Using Existing Distribution Protection and Control Capabilities for Integration of Distributed Energy Resources

Shawn Shields, Gandhali Juvekar, Cole Salo, and Bill Glennon
Schweitzer Engineering Laboratories, Inc.

Presented at the
51st Annual Western Protective Relay Conference
Spokane, Washington
October 22–24, 2024

Using Existing Distribution Protection and Control Capabilities for Integration of Distributed Energy Resources

Shawn Shields, Gandhali Juvekar, Cole Salo, and Bill Glennon, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Distributed energy resources (DERs) have created new challenges for traditional protection and control schemes in power systems. With the ever-growing penetration of these resources, distribution engineers are increasingly challenged in selecting reliable protection, control, and communications solutions that operate correctly at the point of common coupling. Advanced solutions that are communications-based or require sophisticated software exist, but they come with significant upfront costs and they are not always available.**

This paper explores the fundamental protection and control solutions currently available to distribution engineers and describes how existing technologies can enable state-of-the-art local schemes to support seamless, reliable, and low-cost DER integration. These solutions are available today and allow additional functionality, like communications, to be deployed in the future. Features available within existing devices can aid in designing practical protection and control solutions that are simple, reliable, and economical. The efficacy of these schemes is described using simulated and field events to help engineers develop ideas for application to their systems.

I. Introduction

The introduction of distributed energy resources (DERs) to power systems has advantages, but it also presents challenges to conventional protection systems. Unlike traditional resources, DERs, especially inverter-based DERs, have low inertia. System short-circuit fault currents with DERs vary widely as compared to a system with traditional generation sources. For inverter-based DERs, the fault currents are not only very low (close to the load current), but also do not possess the sequence-component characteristics that the fault currents arising from short-circuit faults in traditional power systems have. This makes it difficult to detect faults in these systems. Depending on the system configuration, the presence of DERs in the system can also desensitize existing protection, causing incorrect operations or even sympathetic tripping on adjacent feeders due to their fault current contribution. For seamless operation, appropriate islanding detection and decoupling are becoming crucial. As the industry works toward standardizing the interoperability and interconnection of these DERs [1], utilities are needing to revisit and revise their protection philosophies to accommodate for DERs and comply with the relevant standards.

Over the past few years, various solutions have been proposed to tackle the multifaceted issue of appropriate protection practices in a system with DERs. Numerous publications on this topic indicate that various local [2] [3] and wide-area solutions [2] [3] [4] [5] [6] have been proposed over the last few years. Multiple field applications suggest that different solutions or a combination of solutions can be effective, depending on the system [7]. Protection elements currently available in protective devices require engineers to perform studies for the correct implementation, which adds complexity. They may also introduce unnecessary tripping delays. For example, definite-time voltage protection settings can be applied based on point-check calculations or user experience, or it can be applied with extensive time delays, which can limit speed, sensitivity, and selectivity. This has caused communications-based protection schemes to gain traction as these schemes are easy to understand and implement. The downside of such communications-dominant protection schemes is that they introduce additional costs, not only from a setup point of view but also from a maintenance perspective because as the system changes, more devices, channels, cables, etc., may be needed. When planning for situations or contingencies where communications are either not present or unavailable, it becomes evident there is a need for effective and easy-to-use localized measurement and control solutions that can be applied today. The solutions discussed in this paper can allow for additional functionality, like communications, to be deployed in the future, or they can simply serve as an effective backup to more advanced wide-area solutions.

Certain traditional and noncommunications-based protection schemes can be leveraged for systems in which communications-based schemes require backup protection or do not make sense due to cost, scale, or level of expertise. Voltage-based protection that uses inverse-time curves (27I, 59I) can be used at the point of common coupling (PCC) for operating and restraining based on voltage level following a short-circuit fault in addition to ensuring compliance to standards like IEEE 1547-2018, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* [1] [8]. Voltage-controlled and voltage-restrained elements (51VC, 51VR) can be applied at the PCC as backup protection for system faults when the power system that the source is connected to is protected by time-current coordinated elements [8]. This protection scheme is easier to apply for systems in which single generators are connected radially to the power system and fault response does not result in elevated fault currents but does result in a low voltage response. This is dependent on the type of source; for example, an inverter-based DER's control mechanism may cause dipped voltage during a fault but causes almost no difference in the pre- and post-fault current outputs. These elements can also be used as a backup to existing communications-based schemes or adaptive schemes when a communications link fails.

Islanding detection and decoupling schemes are implemented to avoid unintentional islanding. Direct transfer trip (DTT) is a common communications-based transfer tripping scheme used in the industry. If communications links are unavailable, local schemes using underfrequency/overfrequency (81), rate-of-change of frequency (81R), and fast rate-of-change of frequency (81RF) can be used [2]. These methods can also be used as a backup for DTT if communication fails to operate correctly.

Restoration is another power system operations topic that has become crucial for utilities to improve their reliability metrics. Like protection, multiple communications-based fault location, isolation, and service restoration (FLISR) schemes exist and are applied to distribution systems [9]. One challenge presented when considering FLISR applications is balancing the need for more switching devices to improve reliability while maintaining fast protection. A beneficial protection and restoration scheme gaining popularity is the high-density coordination (HDC) scheme with dual benefits: fast detection of a permanent fault on a system with devices that have tight operating margins followed by service restoration wherever possible. The scheme uses logic that reduces settings complexity, improves accurate fault location, and ensures fast fault clearing of permanent faults all without the requirement of a communications link [10]. The HDC scheme performs restoration from the source to the location of the fault, without adding time delays to existing coordination, using local voltage measurements to initiate a stepped reclosing sequence. For more complex restoration, HDC operates up to the point of the protective relay nearest the fault locking out and FLISR can then restore the remainder of the system. Protection engineers with a fundamental understanding of the topic can apply HDC to their system with minimal studies to achieve significant reliability improvements with no added tripping delays.

Optimization of the distribution system becomes a primary interest when the system is in a steady state and loads have stabilized. Effective management of voltage levels and reactive power management can be challenged when increasing line-switching capabilities and adding DERs to the system. A communications-based volt/VAR optimization (VVO) scheme provides the best overall situational awareness for leveling feeder voltage profiles and managing reactive power in more heavily loaded and complex systems [11]. Advanced features found in modern intelligent electronic devices (IEDs), specifically step-voltage regulator controls (VRCs) and switched capacitor bank controls (CBCs), can perform many of the same functions as the communications-based VVO systems. With proper placement on the distribution feeder and settings configured correctly, advanced VRCs and CBCs can perform local VVO with simplified settings and adapt their algorithms in response to abnormal operating conditions.

This paper details the protection, restoration, and optimization schemes described here and explores applications, implementations, and results using field data. In many present-day systems, the devices needed to implement these functions are likely devices already installed and in operation. They may not be using the protection and control logic discussed but the devices will demonstrate a level of familiarity to their users, easing adoption. These devices include recloser controls (RCs) at the PCC and for HDC, VRCs to manage distribution voltage profiles, and capacitor bank switching controls to manage reactive power control.

II. Improving System Restoration, Coordination, and Fault-Clearing Times With RCs

Faults in the distribution system can lead to interruptions that challenge a distribution utility's goal to provide reliable service to their customers. Reclosers and sectionalizing schemes have been adopted to isolate the fewest customers possible during outages caused by permanent faults. In the event of a permanent fault, post-fault communications-based restoration systems, such as FLISR, provide unmatched performance restoring service to as many customers as possible beyond the fault. To accomplish isolation goals (e.g., the ability to isolate every 500 customers), more reclosers and switches are added to a distribution system. However, adding additional reclosers can impact time-overcurrent coordination, slowing down protection, or require detailed planning for various sectionalizing and switching operating modes. HDC schemes, detailed in [10], achieve system restoration up to the point of the fault by adding reclosers into the system without slowing down protection or requiring the design of complex sectionalizing schemes. In addition, communications and FLISR applications complement HDC to restore service beyond the permanent fault where possible, further improving reliability.

A. *Recloser Operations*

The physical capabilities of modern reclosers and RCs are well understood by their users. These capabilities have been available for many years and include the ability to measure voltages on both the load and source sides of the protective device, break fault current, and reclose after operating for a fault. Effectively, we can think of these pole-mounted devices as a "substation on a pole." Historically, distribution protection engineers have achieved selectivity between reclosers through time-current coordination. With only a few reclosers in series, there is sufficient coordination margin between the time-current curves of each recloser. The inverse-time overcurrent curves for these reclosers are constrained by the operating speed of downstream protection and the damage curves of upstream substation transformers [12]. This method of protection has been very effective in protecting radial distribution feeders. An example of a feeder relay and single RC coordination curve plot with adequate margin is shown in Fig. 1 [12].

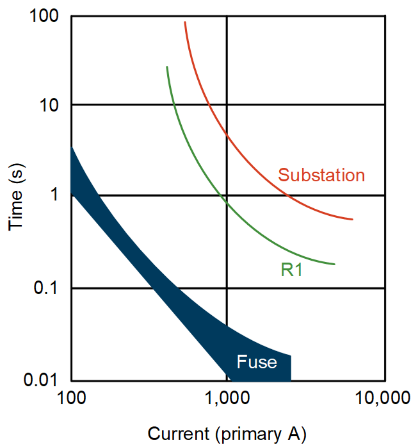


Fig. 1. Overcurrent curves with adequate coordination margin [12].

B. *Challenges With Traditional Time-Overcurrent Coordination*

Time-current coordination requires an operating time difference between two devices when a fault occurs on the system. In simple terms, this means that an upstream device that detects a fault will intentionally delay operation to give a downstream device the opportunity to clear the fault first to continue to provide service to the maximum number of customers. As the inverse-time overcurrent curves for each recloser are constrained by the operating speed of its neighboring devices, increasing the density of recloser installations reduces the available margin between successive devices. Consequently, setting these RCs using traditional coordination practices becomes more complex, as shown in Fig. 2 [12]. In some cases, it is simply not possible to add additional reclosers because they cannot be properly coordinated.

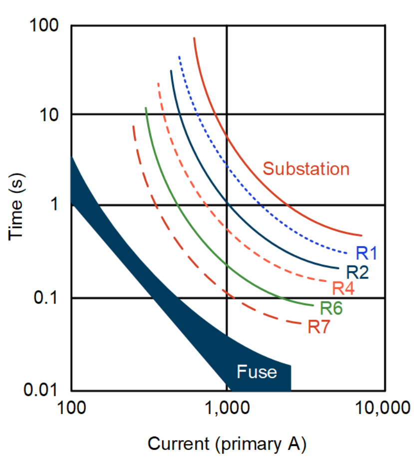


Fig. 2. Reduced coordination margins with traditional coordination [12].

Additionally, the time delay needed on upstream devices increases every time a new recloser is added to the system. Obviously, this has the potential to result in long trip times for faults that are directly downstream of the first protective device. Depending on the location of the additional recloser, it could also require settings changes in several other reclosers when new devices are added to the system. For example, if a new protective device is added in the middle of the system, both the upstream and downstream protection settings would have to be evaluated to ensure that the coordination of the entire system is reliable. Upstream devices may have to slow down operation and downstream devices may have to speed up operation. These fault studies and settings configuration changes add cost and complexity to users.

C. *HDC Solves Coordination Challenges*

The most impactful innovation in the distribution recloser segment is coming in the form of flexibility of protection functions and programmable logic these devices provide. The enhanced functionality that comes with programmable logic allows RCs that have been in service for many years to provide protection, automation, and control schemes that were not widely implemented when they were installed. One such method of protection and control is HDC [10]. HDC requires that the recloser have the ability to measure voltage, ability to break fault current, fault detector elements, inverse-time overcurrent elements that can enable different operating characteristics, and programmable logic. The general concept of HDC is that any number of reclosers can be installed on a line using the same settings for all devices without having to be concerned with time-current curve coordination. There are two implementations of HDC: one that requires communications and one that only relies on local measurements [10]. Both methods result in faster trip times than traditional time-overcurrent coordination and isolate the fault to a single line segment. In this paper, we are only referring to the noncommunications-based HDC method as it can be implemented on new and existing reclosers without any additional infrastructure needing to be installed.

With HDC, the system is broken up into coordinated groups. Each coordination group uses the exact same protection settings to detect and clear faults. Each group is then designed to coordinate with the downstream groups using traditional time-overcurrent coordination methods. Time-coordinating groups reduce the number of devices that need to fit on the time-current curve, and thus allows the system to shift the curves down and make operate times for the entire system faster. The application of HDC results in multiple devices operating for a single fault, which traditionally would be referred to as miscoordination. However, the HDC logic is designed for this exact condition, which is referred to as "group tripping." After the group trips, the first protective device in the group starts the process of "stepped reclosing," as shown by the example in Fig. 3, in which a fault occurs between R6 and R7.

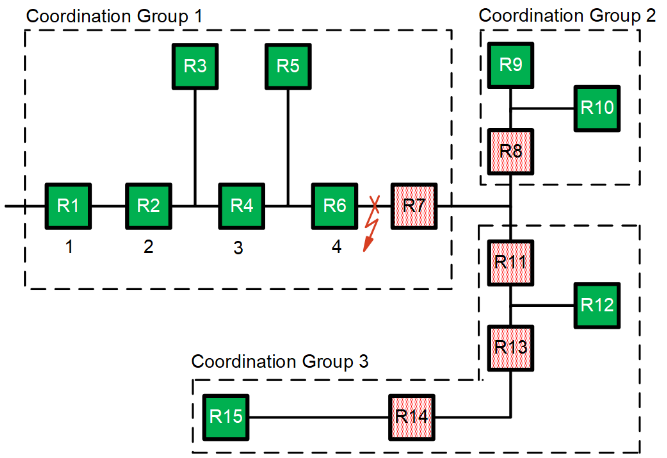


Fig. 3. Example HDC feeder with coordination group tripping due to a fault.

R1, R2, R4, and R6 all detect a fault and trip, causing an outage. The initiation signal of the stepped reclose is voltage being measured by the device. In this example, R1 is the first device to initiate the restoration process. A short period of time after measuring the voltage, the device attempts a reclose with an inverse-time overcurrent element enabled that has an operating time that is faster than the upstream device. This element is also supervised by a second harmonic element to reliably detect load and inrush current from fault current. Enabling the element with a fast curve provides coordination between devices in the same protection group that are using the same protection settings when the device recloses into a fault. If the fault is not on the segment of line that just performed the reclose after a short time delay, the device reverts to the slower curve, and the next device in the system measures voltage and starts its reclosing sequence with the fast curve enabled. This procedure results in either all devices in a protection group tripping and then reclosing successfully for a temporary fault or it results in a recloser closing into a fault and then tripping and reclosing until locking out after a preconfigured number of attempted recloses. In the example, R6 is the last device in Coordination Group 1. It locks out due to the permanent fault.

Implementation of this scheme [10] in either new installations or existing installs results in faster fault-clearing times, system restoration up to the location of the fault, reduction of fault location time because of a reduction in the amount of line that could potentially be faulted, simplified settings, reduced engineering time, improved reliability metrics, elimination of coordination concerns in existing systems, and increased segmentation of the distribution system. The settings are designed to detect faults, operate quickly, and then reclose based on the voltage. At first glance, it is not intuitive how HDC aids in the integration of DERs. However, looking further into the entire system, it becomes clear that HDC has a significant impact on fault-clearing times. The faster clearing times allow for DERs to be integrated into systems without having to participate in fault-clearing schemes, with the exception of faults that occur between the PCC and the electric power system (EPS), which are easier to identify once the EPS is no longer providing fault current. Additionally, because coordination is not a concern, adding reclosers near the PCC tap into the EPS reduces the amount of line that needs to be protected between the PCC and the adjacent reclosers.

III. Protection Solutions for DER Integration

Traditionally, distribution systems were mostly radial in nature, with the area EPS source feeding the system feeder and laterals. Protection schemes like inverse- and definite-time overcurrent combined with the autoreclosing technology proved sufficient for protection of the feeder. With increasing penetration of DERs, system complexity is increasing. Protection schemes that the industry long relied on were not designed for such systems. Because DERs characteristically have low inertia, they fail to supply sufficient fault currents during short-circuit faults. The fault currents generated by inverter-based DERs have low magnitudes and result in atypical sequence currents. Traditional overcurrent protection cannot be applied to systems in which DERs are primary sources, like systems in islanded mode. DERs may also desensitize existing protection by lowering the amount of fault current from the primary source, causing the protection to misoperate. They may even cause tripping on adjacent feeders due to circulating fault current contribution [4]. Sometimes, protection may cause unintentional islands on the system, which become incapable of continued operation and may cause a system collapse. This makes implementing appropriate islanding detection schemes important. Keeping this analysis in mind, the following protection schemes are detailed and can be implemented depending on the application—fault detection or islanding detection. All of the protection functions in this section of the paper are available in advanced RCs. This simplifies the installation of the PCC device and significantly reduces the installation costs.

A. *Inverse-Time Undervoltage and Undervoltage Protection Schemes (27I/59I)*

Definite-time voltage-based elements are commonly applied when a DER connects to the electric utility, aiming to isolate the DER from the utility at the PCC during abnormal voltage conditions. However, the settings for definite-time voltage elements are often determined through point-check calculations or user experience, or by compromising speed for time selectivity with a significant time delay, all of which can limit speed, sensitivity, and selectivity. These elements are also not very selective by nature, which is a significant disadvantage.

A novel method was developed and described in [8] to coordinate definite-time and inverse-time voltage-based protection at the PCC with overcurrent devices on the feeders. The method can be used as primary or backup protection at the PCC at which the DER is connected laterally to the area EPS. The settings for the scheme can be made based on coordination requirements as well as IEEE 1547-2018 standard compliance. The concept behind this method is explained in great detail in [8]. To summarize, the impedance of the DER source for most distribution systems is much larger than the area EPS source. This means that the fault current contribution from the DER source can be ignored as most contribution is from the area EPS source. This also means that the voltage measured at the PCC is the result of a voltage divider between the area EPS source impedance and the impedance of the line downstream of the PCC. Fig. 4 demonstrates this simplification. One observation that can be made is that the PCC experiences large deviations in voltage for downstream feeder faults, so it makes sense to utilize voltage measurements rather than current measurements at the PCC for a more reliable indication of feeder faults. Fig. 4 shows that depending on the fault location, the value of $\eta \cdot Z_L$ is unique at the PCC (where η is normalized impedance length), and the magnitude of voltage at the PCC can be used to achieve selectivity for area EPS faults.

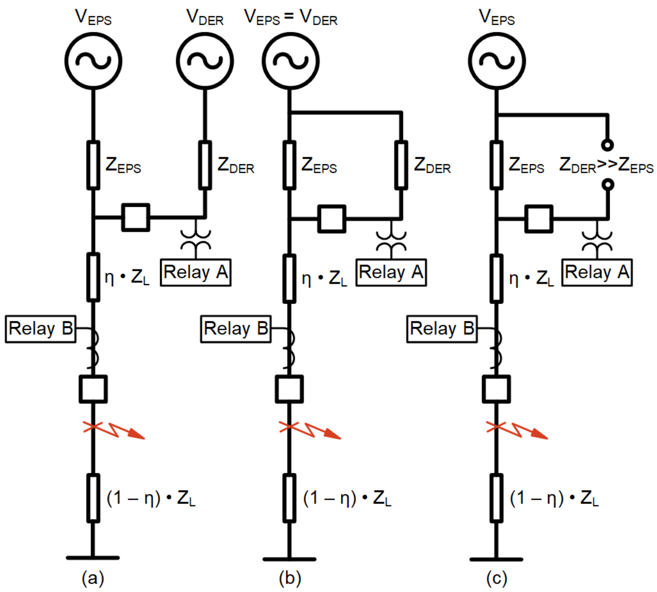


Fig. 4. Simplified circuit diagram of the voltage divider at the PCC.

The method utilizes a time versus normalized impedance length (TNIL) plane for coordination of the inverse voltage curves of the PCC relays with the overcurrent relays downstream. This helps visualize the trip time coordination for both overcurrent and voltage-based relays depending on the location of fault. The details on how to obtain the TNIL plane for various fault types and fault locations using the appropriate operating quantities are described in [8], along with the computation description in the appendix of that paper. Fig. 5 and Fig. 6 are examples of how the TNIL plane looks for a system with PCC at $\eta = 0$ and the feeder recloser at $\eta = 0.3$ for LL faults. Here Relay A is the PCC protective device and Relay B is the RC. Fig. 5 shows the timing characteristics for voltage and current elements in Relays A and B. Fig. 6 shows the composite response for Relays A and B for feeder faults.

For acceptable operation of resistive faults that do not cause a severe change in voltage, a definite-time voltage element can be used. The TNIL plane can also be extended beyond the protected line ($\eta > 1$) to represent resistive faults. Additionally, a definite-time voltage element can be used in conjunction with the inverse-time voltage element to achieve speed and IEEE 1547-2018 standard compliance. To avoid unintentional islanding during system faults, the inverse voltage elements can be used as a solution wherever applicable. This solution, however, is mainly a fault detection solution.

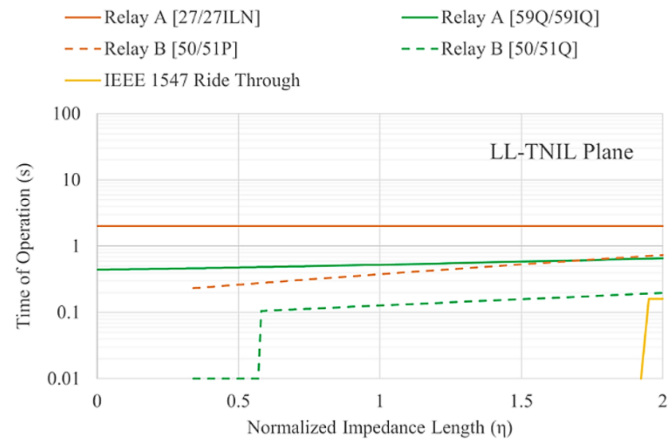


Fig. 5. LL-TNIL characteristic example for all available 27/27I, 59/59I, and 50/51 relays [8].

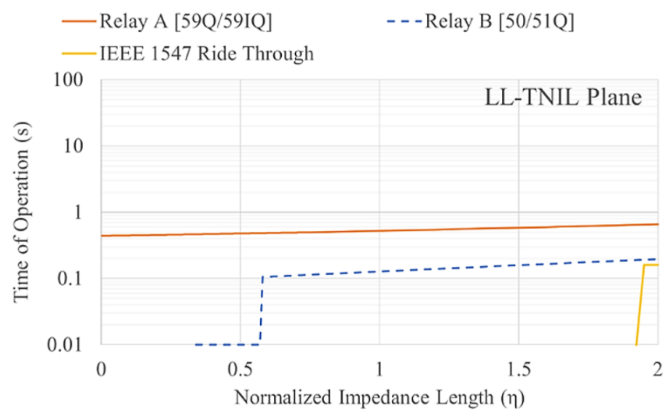


Fig. 6. Composite characteristics of Relays A and B on the LL-TNIL plane [8].

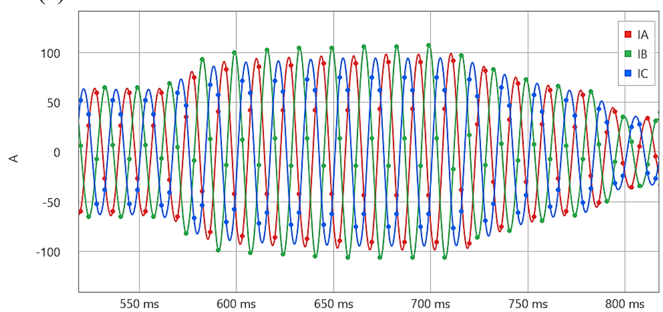
This method is not effective for all system configurations including for islanded mode, a strong ground source supported by the DER, and DERs that respond to faults in a more traditional manner.

To summarize, canonical models can be developed using source and feeder impedances. This approach facilitates the correlation of voltage and current for faults at all locations along the area EPS feeder, forming the basis of the TNIL plane. On this plane, coordination between different types of voltage and current elements can be uniquely established for each fault type. This method, hence, solves the problem of coordination between a feeder relay and the PCC relay and helps alleviate the problem of choosing protection strategies for systems with DER penetration.

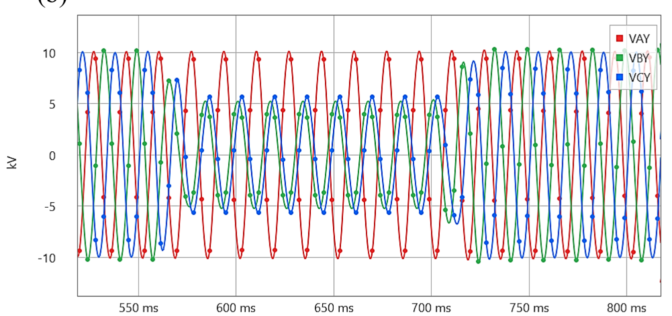
Fig. 7 illustrates the coordination of the PCC IED to a downstream LL fault on a system whose LL-TNIL characteristic is shown in Fig. 6. The PCC IED is equipped with the inverse voltage elements set to respond like Relay A in Fig. 6. The fault occurred at $\eta = 0.6$ in the middle of the section that Relay B is protecting. Relay B operates as expected, and the PCC relay detects the fault but does not trip as the downstream recloser clears the fault in about 0.14 s, as seen in Fig. 7(c) when the system returns to normal. Note that the assertion of the 27I and 59I binary elements indicates that the voltage elements are picked up timing to trip, and the 27IT and

59IT binary elements never asserting indicates that the inverse voltage trip elements never timed out.

(a)



(b)



(c)

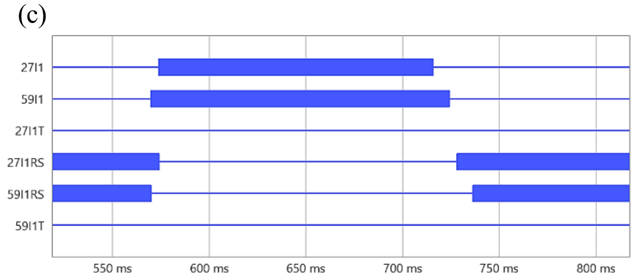
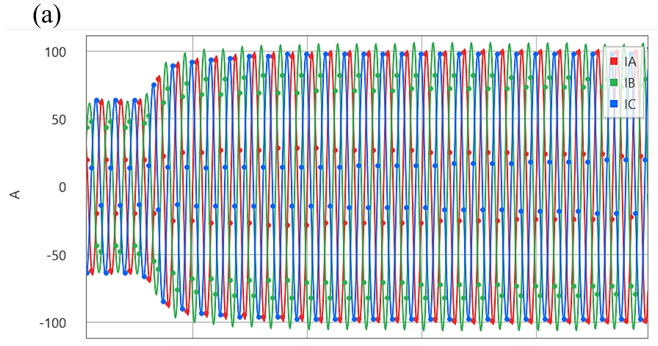


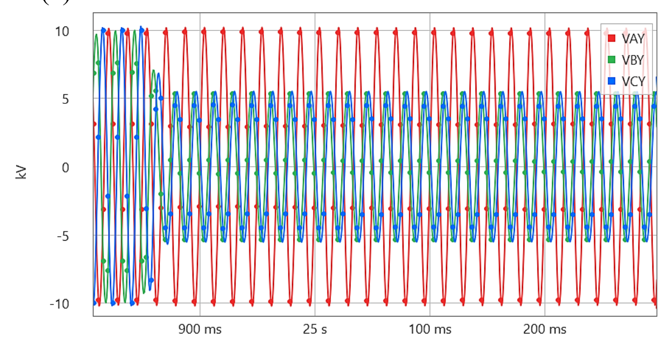
Fig. 7. Current (a) and voltage (b) waveforms for the fault and the IED response (c).

Fig. 8 illustrates the response of the PCC IED to the same downstream LL fault on the system as that shown in Fig. 7. Relay B fails to operate as expected, creating abnormal operating conditions for the DER connected to the PCC. The PCC relay detects the fault and trips while complying with IEEE 1547-2018. Note that the assertion of the 27I and 59I binary elements indicates that the voltage elements are timing to trip, and the 27IT and 59IT binary element assertions indicate that the inverse voltage trip elements timed out.

(a)



(b)



(c)

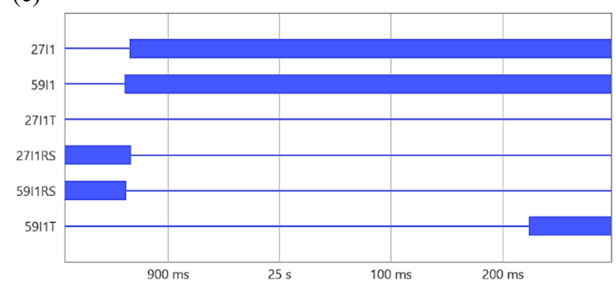


Fig. 8. Current (a) and voltage (b) waveforms for the fault and the IED response (c).

B. Voltage-Controlled and Voltage-Restrained Overcurrent Protection Schemes (51V: 51VC and 51VR)

Voltage-controlled or voltage-restrained overcurrent protection uses a measured voltage and current. The main function of 51V, traditionally, is to provide backup protection for system faults when the power system that the source is connected to is protected by time-current coordinated protections [13]. With DERs integrated in the system and the lack of typical fault currents they supply, the applicability of 51V is increasing. Depending on the DER control mechanism, the fault current characteristics of the DER vary widely. It has been observed that feeder faults downstream of the PCC do cause lower voltage levels during the faults. This fact is leveraged by the 51V protection schemes that can be set to provide backup protection to the DERs. The scheme is designed to restrain operation under emergency overload conditions and still provide adequate sensitivity for the detection of faults.

These elements use the measured voltage to increase the sensitivity of the inverse-time overcurrent elements. This allows traditional inverse-time overcurrent curves protecting the EPS to be coordinated with the PCC overcurrent element curves even though the fault currents provided by the DER are significantly less than the EPS. This simplifies the process of coordination for engineers who define settings for the PCC relay to work in sync with other feeder relays.

1) *Voltage-Controlled Overcurrent Scheme (51VC)*

The method measures both PCC voltage and current magnitudes and operates when the measured voltage for a phase is below a voltage threshold value and the phase current is above a current pickup value. Fig. 9 demonstrates the operating region for a 51VC element.

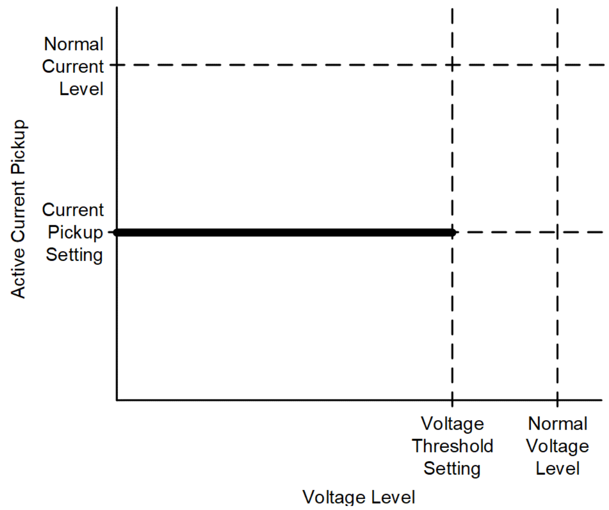


Fig. 9. Generic 51VC operating characteristics.

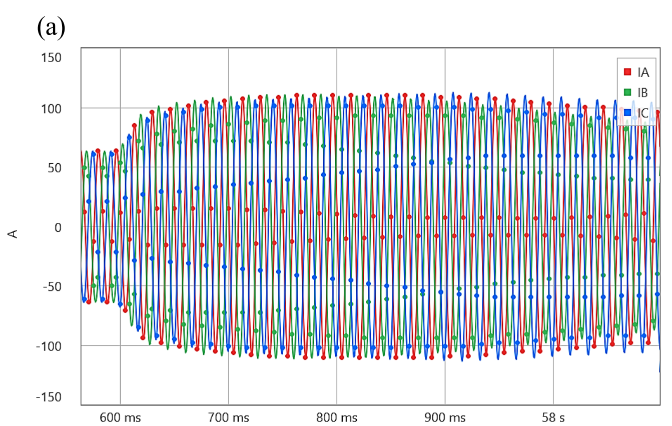
The pickup for the 51VC element can be set using the recommendation from the IEEE Guide C37.102-2023, *IEEE Guide for AC Generator Protection*, for DERs that are alternating current (ac) generators:

Current pickup = 50 percent of nominal current

Voltage threshold = 75 percent of nominal voltage

For DERs that are inverter-based, these settings can be used as a starting point and changed based on the DER voltage and current response to system faults and the coordination goal with feeder relays.

Fig. 10 illustrates the response of the PCC IED to a downstream LLG fault on the same system as that shown in Fig. 7. The PCC IED is equipped with the 51VC element set to operate as backup protection to the PCC primary protection scheme. Relay B fails to operate for the LLG fault downstream of it, and the PCC relay detects the fault. The operate time is 0.45 s as seen in Fig. 10(c) when the 51VC element times out.



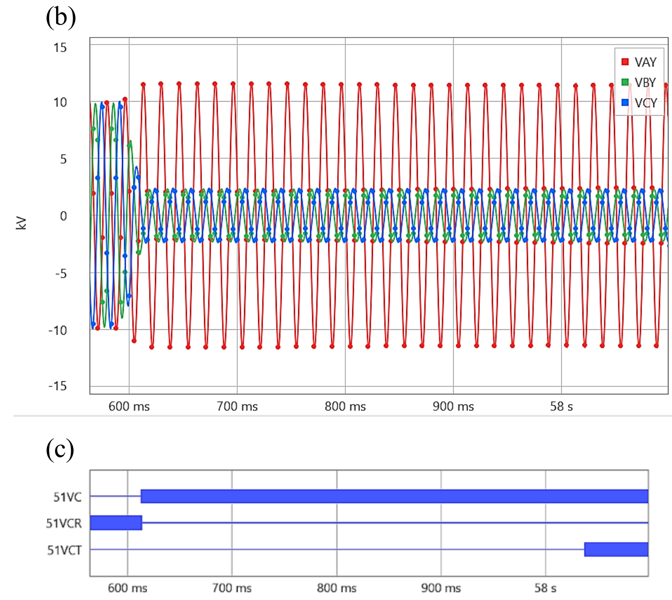


Fig. 10. Current (a) and voltage (b) waveforms for the fault and the IED response (c).

2) *Voltage-Restrained Overcurrent Scheme (51VR)*

This method measures both PCC voltage and current magnitudes. The per-phase current magnitude is normalized by dividing the quantity by the corresponding phase's normalized voltage. Under fault conditions, the more depressed the voltage is, the more sensitive the time-overcurrent function becomes. The overcurrent pickup level must be set with a margin above the generator's full-load current. Additionally, the normalized voltage value may be limited. For example, the scheme in Fig. 11 limits the normalized voltage as [0.125, 1]. Fig. 11 demonstrates the operating region for a 51VR element.

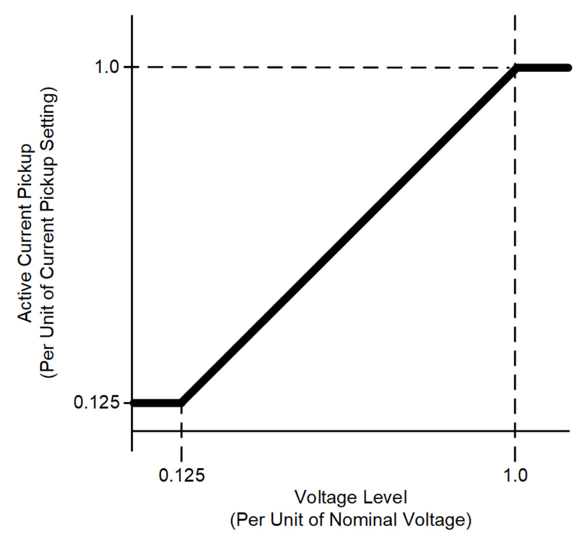


Fig. 11. Generic 51VR operating characteristics.

The pickup for the 51VR element can be set using the recommendation from the IEEE Guide C37.102-2023 for DERs that are ac generators:

Current pickup = 150 percent of nominal current

Similar to 51VC, for DERs that are inverter-based, this setting can be used as a starting point and changed based on the DER response to system faults and coordination requirement with feeder relays.

Fig. 12 illustrates the response of a PCC IED to a downstream 3P fault on the same system as that shown in Fig. 7. The PCC IED is equipped with the 51VR element set to operate as backup protection to the PCC primary protection scheme. Relay B fails to operate for the 3P fault downstream of it, and the PCC relay detects the fault. The operate time is 0.391 s, as seen in Fig. 12(c) when the 51VR element times out.

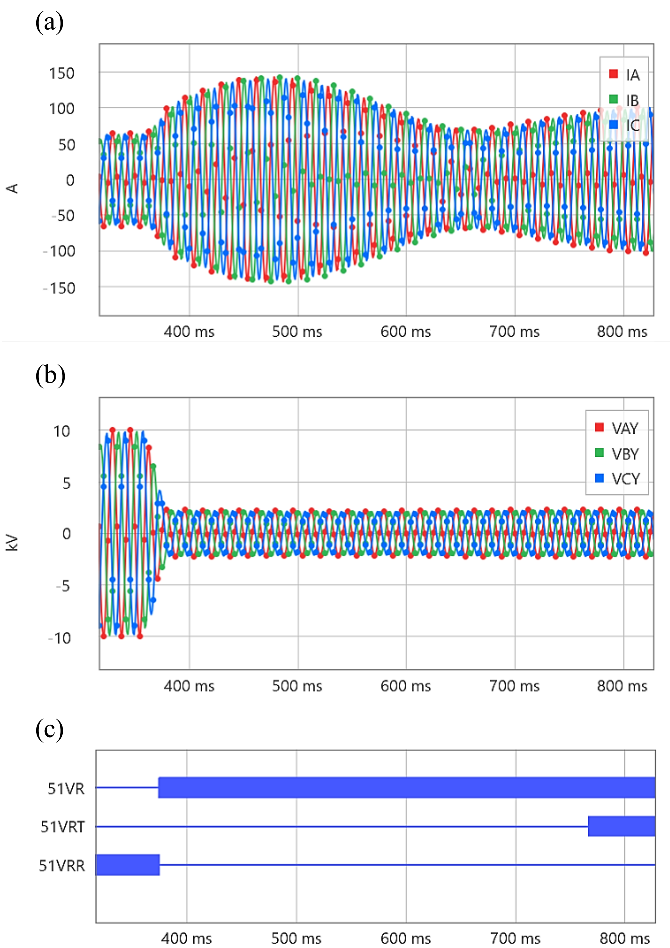


Fig. 12. Current (a) and voltage (b) waveforms for the fault and the IED response (c).

Coordination using the 51V scheme is easier to achieve for single generators connected to radial interconnection. Extreme loading conditions should be carefully evaluated before setting up this scheme. Depending on the complexity of the system, a detailed analysis may be required to set up this scheme. To summarize, the 51V scheme can be used for coordination and may also be used as primary protection for faults on the line between the DER source tap point and feeder relays.

C. *Frequency-Based Islanding Detection Schemes (81/81R/81RF)*

With increased DER penetration in distribution systems, islanding detection has become an important aspect of system protection. When DERs and part of the area EPS unintentionally island due to protection operation, it may result in the DER(s) becoming the primary source(s) in the island(s). If the DER was not designed to operate in this system configuration, a generation and load will not be balanced, causing underfrequency (or overfrequency) conditions, potentially leading to system collapse. Alternatively, some system islands may be capable of continued operation after disconnection from the area EPS but must know that the system is in islanded mode to reconfigure various system settings like protection, restoration, and optimization. The most commonly used method for the PCC relay to trip after islanding detection is DTT. DTT can be implemented using communications protocols and is agnostic to the type of protocol used. Reclosers at the PCC provide noncommunications-based solutions for primary islanding detection methods or as a backup to DTT.

1) *Underfrequency and Overfrequency (81)*

Disturbance detection and successful islanding detection followed by decoupling can be achieved using abnormal frequency detection. It is imperative to coordinate these schemes with existing system protection and compliance with the IEEE 1547-2018 standard to avoid incorrect tripping. Existing RCs provide multiple frequency elements for underfrequency as well as overfrequency detection. Depending on the speed at which an islanded DER's frequency drifts, it may take considerable time for the frequency to exceed a pickup and begin the timer. This could leave consumers islanded by a DER longer than desired.

2) *Rate-of-Change of Frequency (81R)*

When the power system is accelerating or decelerating, a rate-of-change-of-frequency scheme can be utilized to detect it. The reason for acceleration or deceleration of the system could be due to scenarios of unbalance between load demand and generation supply. If the acceleration or deceleration rate is beyond a detection threshold dictated by the utility standard or the IEEE 1547-2018 standard, depending on the category of DER system, a system disturbance is detected and a decoupling scheme can be initiated. Additionally, a decoupling scheme can also be set to detect islanding conditions. Existing RCs provide multiple rate-of-change frequency elements (81R) for application to the DER tap point or the PCC. Such a scheme can typically respond more quickly to detect an island formation than the traditional 81 element.

3) *Fast Rate-of-Change of Frequency (81RF)*

The 81RF functionality is the same as that of the 81R in that it detects the acceleration or deceleration of the system due to unbalance between load and generation. But the dynamic pickup established by the depth of a frequency excursion from nominal results in faster performance of the 81RF compared with the frequency (81) and rate-of-change-of-frequency (81R) schemes.

Some systems may require faster response times not achievable using 81 or 81R, and 81RF may be able to provide the required speed. The application of 81RF for such cases may prevent system failures and even blackouts.

In [2], when the system is steady, the operating point exists close to the origin. In the 81RF characteristic in Fig. 13, the x-axis is frequency deviation from nominal and the y-axis is the rate-of-change of frequency. This characteristic can be used to detect islanding conditions. After disconnecting from the area EPS, the frequency, as well as the rate-of-change of frequency detected at the PCC relay, enters the operating region shown in Fig. 13. For an accelerating system, the operating point enters Trip Region 1, and for a decelerating system, the operating point enters Trip Region 2.

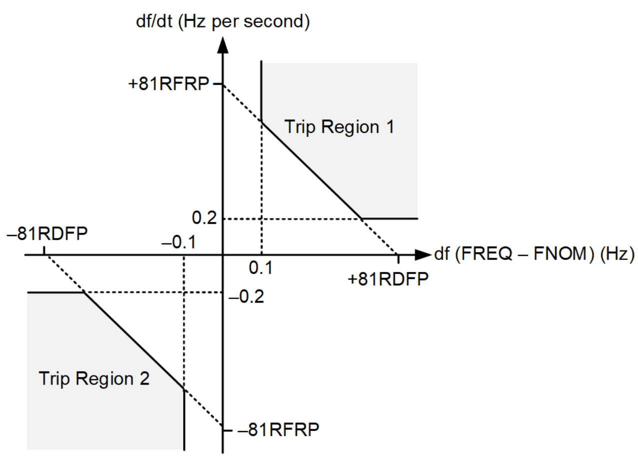


Fig. 13. 81RF characteristics.

Sometimes, islanded mode may be a valid operating mode of the system and the 81RF scheme can help a microgrid survive after disconnecting for a fault on the area EPS. This condition is known as seamless islanding. This may be achieved even with IEEE 1547-2018 compliance.

The challenge with the 81RF scheme is that it is harder to configure as compared to the frequency (81) and rate-of-change-of-frequency (81R) schemes. The engineer is required to perform system studies to identify frequency difference set points (df) and the df/dt set points, which determine the slope in the graph shown in Fig. 13. One set point can be df = 2 Hz and df/dt = 3 Hz/s based on [1], and the other can be set based on maximum frequency excursion caused during system disturbances. In summary, the fast rate-of-change-of-frequency element can be used to detect islanding and help with decoupling the system to avoid system collapse.

IV. Improving System Optimization With CBCs and VRCs

When the distribution system is in a steady state, system operators look to optimize their system by minimizing losses and maximizing efficiency. Two important aspects of optimization are effective management of voltage levels and reactive power management. As increasing line-switching capabilities and DERs are deployed, asset settings management becomes increasingly complex. It can be easily understood that a communications-based VVO scheme provides the best overall situational awareness for leveling feeder voltage profiles and managing reactive power in more heavily loaded and complex systems. In an advanced distribution management system (ADMS), a control center communicates with IEDs to collect data from the field, analyze the system, run control algorithms, and then send control commands back to individual devices [11]. Advanced features found in modern IEDs, specifically step VRCs and switched CBCs, can be coordinated to perform VVO similar to that available in an ADMS yet do not rely on advanced communications and sophisticated wide-area control software. These advanced VRCs and CBCs can perform local VVO with simplified settings to adapt to abnormal operating conditions. Using these advanced VRCs and CBCs, which natively support communications, also provides an upgrade path to ADMSs in the future with local control algorithms to serve as an effective backup.

A. Bidirectional Power Flow Impact on VRCs

As distribution feeders evolve with the proliferation of DERs and increasing power system interconnections, traditional VRC strategies are challenged because they are configured based on power flow direction. A newer, more flexible mode that evaluates the voltage change across a tap operation and adapts voltage regulation direction meets these challenges and comes with additional benefits. The control becomes easier to set, can detect and adapt to abnormal operating conditions, and can seamlessly accommodate changes as assets are installed on the system. To understand how an advanced operating mode using local measurements solves these challenges, a review of how traditional control modes handle bidirectional power flows as well as their shortcomings is in order.

1) Step-Voltage Regulator Operation

A voltage regulator is a single-phase tap-changing autotransformer in which the voltage of the regulated circuit is controlled in steps without interrupting the load [14]. They maintain voltage at a predetermined level and ensure undesirable voltage conditions are avoided, which can lead to flickering or dimming lights, reduced efficiency, and costly equipment repairs and maintenance. The art of voltage regulation with traditional VRCs is generally well understood by their users. It is assumed that the reader has a solid foundation of the control modes and capabilities available in VRCs. If needed, the operation and capabilities are covered thoroughly in [15].

A typical radial feeder circuit example is shown in Fig. 14, in which a voltage regulator is installed in a midline position at which power flows through the voltage regulator from source to load. In this configuration, the regulated voltage is in the forward direction. This is shown in Fig. 14 as a one-line diagram in the lower part and a voltage level profile graph in the upper part. The regulation point, represented by the load center of the line, is the defined location that voltage is controlled at. The control band is shown as a gray bar with the set points labeled as upper and lower band.

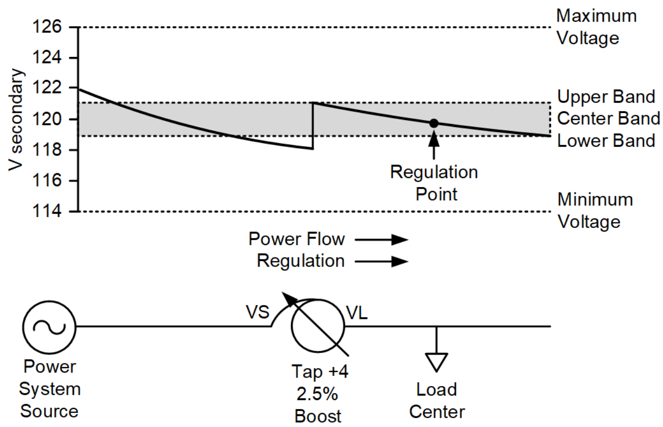


Fig. 14. Forward regulation voltage profile.

a) Voltage Regulation in a Loop Circuit

In a loop circuit, normally more than one power system connection is available but only one connection is expected to be utilized at any given time. Traditionally, on this type of circuit, the voltage regulator is expected to experience reverse power flow because of line-switching events that occur during normal operation. Either VS or VL can be associated with the power system source voltage and the other voltage (VL or VS) would be the regulated voltage. An example of a loop feeder arrangement is shown in Fig. 15.

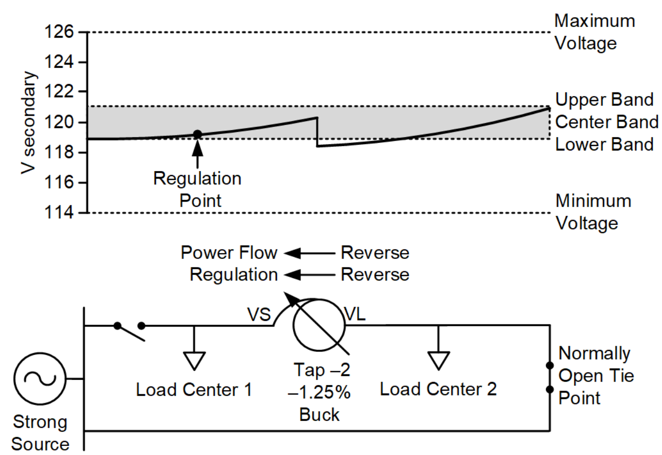


Fig. 15. Loop circuit bidirectional voltage regulation during reverse power flow condition after a line-switching event.

During normal system configuration, power flows forward and VL is regulated. When a switching event occurs, the VRC measures the power flow reversal and switches the regulated voltage to VS.

b) Voltage Regulation in a Multivoltage-Source Circuit

A normal radial feeder can have additional sources brought online to support demand. These additional sources may be DERs, which come in many forms, and these are specified in IEEE 1547 [1]. In some cases, the DER does not participate in voltage regulation, although more often, it has a limited ability to regulate voltage. In either case, operation of a DER will produce a voltage rise, so utilities must rely on other assets for voltage regulation. For these reasons, the DER is considered a weak source.

When a voltage regulator is on a radial circuit with a DER and loads downstream from it, a low load condition may cause the DER to generate more active power than what is consumed by its local loads. An illustration of this situation can be seen in Fig. 16, in which the DER is supplying active power through the voltage regulator to Load Center 1. The characteristic voltage profile of this two-source circuit is seen as a U-shaped curve. Since the DER is a weak source and the power system is a strong source, regulation must remain in the forward direction. The weak source will produce a voltage rise, so it is desirable to maintain voltage regulation at Load Center 2 to prevent an overvoltage condition caused by the DER.

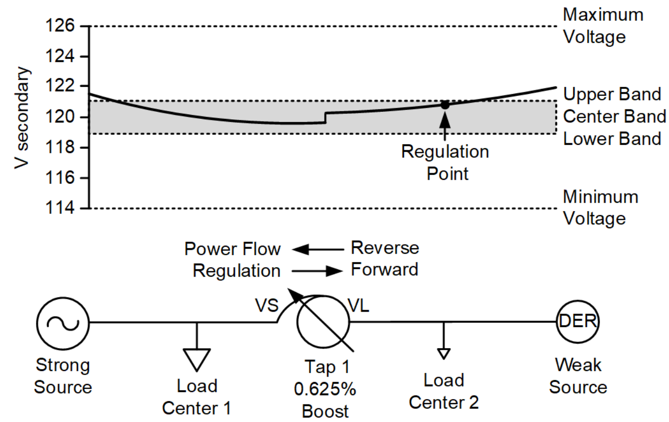


Fig. 16. Voltage regulation under reverse power during DER export.

While this DER export is occurring, the VRC will measure a reverse power flow, but regardless of measured direction, regulation must remain in the direction toward the weak source. As shown, desired regulation direction does not follow the power flow direction. Therefore, a control mode that ignores power flow is required.

2) Voltage Regulation Challenge in Complex Feeders

As illustrated in Section IV.A.1, when the voltage regulator can experience bidirectional power flows, the traditional method of selecting a control operating mode requires configuring a response based on measured power flow direction. When reverse power is expected to come from line switching, as shown in the loop circuit example in Fig. 15, then bidirectional mode ensures that regulation direction follows real power flow direction. If instead, reverse power is expected to come from DERs, as seen in the example in Fig. 16, then forward locked mode ensures regulation is always forward with the strong power system source behind it. A problem arises when the voltage regulator can experience bidirectional power flows but there is no clear delineation between strong and weak sources as they relate to power flow. This can be the case when DERs and automated line-switching capabilities coexist on the same network. Consider the feeder with DER shown in Fig. 16 when the intertie connection in Fig. 15 is added to the system. This new system is shown in the one-line diagram in Fig. 17.

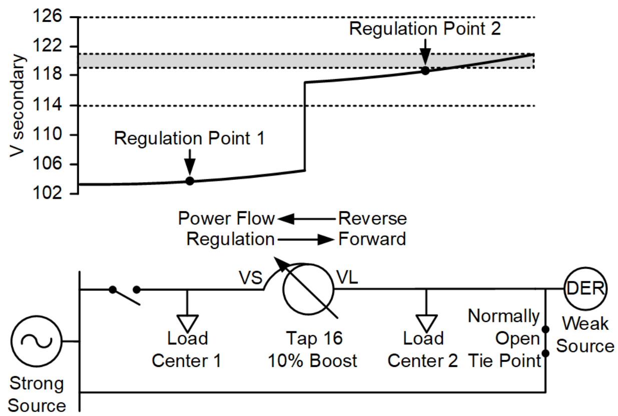


Fig. 17. Undesired voltage profile when the voltage regulator is at maximum tap position.

In this example, there can now be two different sources of reverse power and neither traditional control mode can accommodate both sources. When reverse power comes because the DER is exporting power, the control strategy is to ignore power flow. But when reverse power comes from a line-switching event, the control strategy is to switch regulation direction. If the regulation direction is incorrect, the regulator may tap to its limit as it tries to correct the voltage on a stiff source and instead force the voltage on the VS to unacceptable voltage levels.

Consider the voltage profile in the example in Fig. 17 in which the voltage regulator is tapped out to its maximum position. Prior to the line-switching event shown, reverse power would have been expected to come from the DER so a mode would have been selected that ignores power flow, as described in the case of Fig. 16. However, in the scenario shown, a line-switching event caused a reverse power flow that now has a stiff source on the VL. With the VRC operating in forward locked mode, the power reversal is ignored. Because the voltage at Regulation Point 2 is below the low band setting, the VRC attempts to raise the voltage on VL by issuing raise commands. Each successive tap position increase can be thought of as pushing against a strong source and will not move the voltage at Regulation Point 2 much, if at all. Instead, the voltage on the VS will decrease with each tap change, driving Regulation Point 1 lower and lower. Eventually, the regulator will tap to its maximum boost position and stop. The voltage profile shown depicts this undesired voltage condition.

3) *Tap-Delta-Voltage Evaluation Is Flexible and Solves Voltage Regulation Challenges*

As shown, power direction determination is not a reliable indicator of change in a strong source. Instead, a VRC must be able to determine which side of the regulator is the nonregulated side (stiffest bus) and which side is the regulated side (weak bus) and adjust its operation accordingly. This can be achieved by utilizing a control mode that evaluates the effectiveness of every tap operation and can switch regulation direction if it determines regulation is ineffective. A control mode that evaluates the step-voltage change across a tap operation (ΔV) provides this functionality [16].

The ΔV method relies on the observation that the relative strength of the sources determines the ΔV on each side of the voltage regulator. This has been shown in detail in simulations and supported by field trials [16]. This flexible ΔV-based mode does not rely on the status of switches, RCs, or DERs and can manage any type of feeder configuration. It could be deployed as a one-size-fits-all control mode to simplify installation and provide secure reliable operation for all system configurations. This control mode also requires no changes when system configurations change (e.g., adding a DER). Also, by utilizing ΔV as a feedback mechanism to evaluate the tap effectiveness, it becomes a closed-loop regulation mode, which can adapt to changes in the system and prevent any runaway voltage conditions from occurring.

B. *Bidirectional Power Flow Impact on CBCs*

Capacitor banks are commonly used to provide VAR support in distribution systems. Capacitor banks have long been in use, but the control systems of when to bring them online continue to evolve.

1) *CBC Methods*

This evolution is pushing from open-loop control to closed-loop control systems. Closed-loop strategies offer greater control because the advanced measurements provide knowledge of VAR demand rather than inferring the need for VARs [17], as we will discuss in this section.

a) *Open-Loop Control Methods*

Two types of simple measurement control strategies are voltage control and voltage, time, and temperature control. Voltage control is simple because it only requires a voltage measurement, which is always available via the control potential transformer. This control strategy relies on the principle that applying shunt capacitors to a system results in a voltage rise. This voltage rise (ΔV) is a consequence of capacitor current (I_C) times the inductive reactance (X_L) of the system from the point of installation back to the source of generation ($\Delta V = I_C X_L$) [18]. Since neither I_C nor X_L is known and static, switching based on voltage level alone can produce unpredictable results.

Incorporating time and temperature has advantages, and it only requires the addition of the time of day and a temperature measurement to implement. It is widely known that there is a correlation between VAR demand and ambient air temperature. This relationship has daily and seasonal cycles. For example, a system during hot weather may have a large demand from irrigation pumps, which are highly inductive in summer, causing the need for reactive power support. A voltage deviation here can be easily corrected by using a capacitor bank providing reactive power support. But that same system may experience a voltage deviation because of high demand from resistive heating elements during winter, requiring little VAR support, if any. In that case, the capacitor bank employing voltage control should be restrained by temperature.

Although both voltage control and volt, time, and temperature control are straightforward strategies that can be effective in predictable and well-understood systems, their settings must be developed empirically. This trial-and-error process may require several seasons to stabilize [17]. The major weaknesses of these strategies are that they only provide a rough indicator of reactive demand and are susceptible to improper switching. Since they offer no feedback, there is no measurement of the success of a switching operation. This can lead to inefficiencies in the system.

b) Closed-Loop Control Methods

With the simple addition of a line current sensor, more advanced control strategies can be employed. These strategies utilize direct measurements of current and voltage to calculate reactive power demand. Traditionally, line current sensors were heavy and required cross bracing to support their being installed on existing infrastructure. This made sensors expensive to install and limited usage of integrating line current measurements into CBCs. Today, however, wireless technology has made it easy to install inexpensive line current sensors with a hot stick, so CBCs can now obtain this information easily. Since reactive power demand is directly related to the current and voltage measurements, VAR control is not only possible but simpler and more accurate than previous methods. VAR control is superior to other methods because when the capacitor bank is switched, the additive effect of the switch operation is directly measured with no influence from other uncontrolled factors [15].

With direct current measurement, advanced features such as adaptive voltage and reactance (AVAR) become possible. AVAR allows for even more precise control because the CBC learns the normal delta voltage (ΔV) and delta VAR (ΔVAR) from historical switch operations and can predict the effect from future switch operations. This feature ensures that the system is not driven outside of the control thresholds and, therefore, helps minimize hunting.

Because VAR control and AVAR use feedback, they are considered closed-loop control strategies. This feedback loop enables the measurement of success of a switch operation and helps better optimize reactive power than that of open-loop control strategies. One disadvantage of a VAR-based control strategy is that the CBC must be in a position on the feeder at which the load current is detected by the sensors and may not be effective with capacitor banks installed near the end of the line.

2) VAR Control Challenges With Bidirectional Power Flows

In a typical capacitor bank installation with current sensors, the sensors are installed on the upstream side of the capacitor bank. This works well for most radial feeder applications because the power flow is always in one direction. The CBC measures VARs supplied by the source. When the close threshold for VAR demand is exceeded, the CBC closes the capacitor bank switch and when VAR demand falls below the open threshold, the CBC opens the capacitor bank switch. An example of this arrangement is shown in Fig. 18.

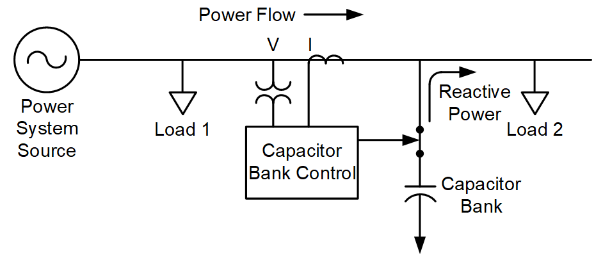


Fig. 18. Switched capacitor bank in radial feeder.

With only one source, active power always flows forward and the capacitor bank supplies reactive power support for Load 2. Challenges are introduced when line-switching capabilities are added to the feeder. Consider the example in Fig. 19 in which multiple sources of power now exist. During a reverse power flow condition, reactive power support is provided for Load 1 behind the capacitor bank. With the switch closed, the measured demand now includes the aggregate contribution from the capacitor bank and the system source.

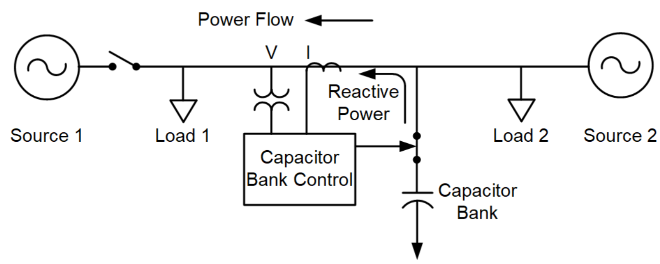


Fig. 19. Switched capacitor bank during reverse power flow condition.

When DERs exist in the feeder, a similar bidirectional situation can occur. Since IEEE 1547 [1] specifies that DERs must be able to import and export VARs, DERs now have more capability for voltage control than they had in the past. However, supplying VARs comes at a cost, so it is an advantage in most cases to offload VARs from the DER by switching in a capacitor bank to avoid penalties and operational costs [11].

3) Bidirectional VAR Control Solves Multisource Challenges

The configuration of a CBC that is designed for use in bidirectional power flow installations has VAR control settings for forward and reverse. The CBC uses power flow direction and knowledge of the switch position to determine if the metered reactive power includes the capacitor bank contribution and adjusts its control algorithm accordingly. The advantages of AVAR control are best realized under forward power flow conditions. With AVAR control active, ΔVAR and ΔV values are calculated using a sample of at least ten forward control operations. During reverse power flow and when the capacitor bank is measuring the aggregate VARs, AVAR control relies on user-entered ΔV and ΔVAR settings.

C. Coordination of VVO Assets in Complex Feeders

As complexity increases in the distribution system, IED time-delay settings should be coordinated for optimal power factor and voltage along the entire length of the feeder. Since voltage regulators, DERs, and capacitor banks all have an influence on voltage, reactive power should be managed before voltage is regulated [11].

IEEE 1547 specifies that DERs must provide both active and reactive power, so engineers must consider DERs employing volt/VAR droop control. One of the goals is to provide voltage support during faults, which means the DER supplies VARs very quickly. However, there is normally a cost associated with this. CBCs with VAR control strategy placed correctly on the feeder measure the VAR demand and switch in when needed. This helps offload VARs from all sources including DERs.

It is advisable that the most downstream CBC operates first, allowing VAR support for local loads and thus helping avoid an overcompensated area elsewhere on the feeder. Each CBC moving upstream should be set with increasing time delays. Once all the CBCs have optimized the VARs, then the VRCs should begin operation starting with the most upstream voltage regulator. Engineers should consider setting the forward time delay on the most upstream VRC to be slower than the slowest time delay of all the CBCs on the feeder. Then, moving downstream, each VRC should be set with increasing time delays. VRC time-delay settings can be independently set for forward and reverse regulation, so after a line-switching event, coordination settings can ensure that the VRC closest to the strong source operates before downstream VRCs operate sequentially.

V. Conclusion

In summary, certain localized protection and control features found in modern RCs, VRCs, and CBCs can aid in designing simple, reliable, and economical solutions to help deal with challenges that come with the introduction of DERs into distribution systems. Highlights of the challenges and solutions discussed in this paper are summarized in the list that follows.

1. DER integration on distribution systems creates new challenges in the protection, control, and operation of distribution systems.
2. The presence of DERs in the system can desensitize existing protection, causing incorrect operations or sometimes even causing sympathetic tripping on adjacent feeders due to their fault current contribution.
3. For inverter-based DERs, the fault currents are not only very low (close to the load current), but they also do not possess traditional fault current sequence-component characteristics, making it difficult to detect faults in these systems.
4. Islanding detection and decoupling are becoming crucial as the industry works toward standardizing interoperability and interconnection of these DERs.
5. Utilities must revisit and revise their protection philosophies to accommodate for DERs and comply with the relevant standards.
6. Communications-based protection schemes (such as DTT at the PCC) and advanced software solutions (such as FLISR and VVO included with a modern ADMS) aid in the deployment of changing, complex distribution systems with DER integration and, often, networked distribution systems.
7. Solutions are available today in modern advanced RCs, VRCs, and CBCs to provide localized protection and controls when (1) communications and software are not present or (2) to serve as effective backup solutions when communications is out of service.
8. As the number of reclosers on a feeder increases to improve reliability and gain flexibility in system configuration, HDC solutions provide significant benefits to maintain protection speeds and security, while simplifying system designs and device settings.
9. Using reclosers at the PCC provides an economical solution with a familiar user interface.
   a) When using voltage-based protection at the PCC, traditional undervoltage and overvoltage elements (27, 59) combined with inverse-time undervoltage and overvoltage elements (27I, 59I) provide greater selectivity and coordination with current-based protective devices on the distribution system.
   b) Voltage-controlled and voltage-restrained overcurrent elements (51VC, 51VR) increase the sensitivity of backup overcurrent protection at the PCC.
   c) Underfrequency and overfrequency (81), rate-of-change of frequency (81R), and fast rate-of-change of frequency (81RF) can be used for fast, local islanding detection.
10. VRC algorithms that employ stiff source detection methods, i.e., tap-delta-voltage evaluation, help solve bidirectional power flow challenges with step-voltage regulators, providing flexibility in the system configuration and the ability to adapt to future changes.
11. CBCs with one or multiple wireless current measurements provide an economical solution for bidirectional VAR-based switching capabilities to help solve capacitor bank challenges caused by multiple reactive power sources on complex feeders.
12. Time-delay settings in VVO IEDs can be set to ensure reactive power flow is optimized first and then voltage profiles are optimized afterward.

VI. References

[1] IEEE Std 1547, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources With Associated Electric Power Systems Interfaces*, 2018.

[2] K. G. Ravikumar, A. Upreti, and A. Nagarajan, "State-of-the-Art Islanding Detection and Decoupling Systems for Utility and Industrial Power Systems," proceedings of the 69th Annual Georgia Tech Protective Relaying Conference, Atlanta, GA, April–May 2015.

[3] J. Mulhausen, J. Schaefer, M. Mynam, A. Guzmán and M. Donolo, "Anti-Islanding Today, Successful Islanding in the Future," proceedings of the 36th Annual Western Protective Relay Conference, Spokane, WA, October 2009.

[4] E. Sortomme, S. Venkata, and J. Mitra, "Microgrid Protection Using Communication-Assisted Digital Relays," *IEEE Transactions on Power Delivery*, Vol. 25, Issue 4, October 2010, pp. 2,789–2,796.

[5] E. Revi, G. Wegh, S. Hollis, A. Abd-Elkader, F. Amuna, and R. Vo, "Grid-Parallel and Islanding Operation Challenges of a Large Battery Energy Storage System at Cape Cod," proceedings of the 76th Annual Georgia Tech Protective Relaying Conference, Atlanta, GA, May 2023.

[6] W. Edwards and S. Manson, "Using Protective Relays for Microgrid Controls," proceedings of the 71st Annual Conference for Protective Relay Engineers, College Station, TX, March 2018.

[7] J. Shiles, E. Wong, S. Rao, C. Sanden, M. A. Zamani, M. Davari, and F. Katiraei, "Microgrid Protection: An Overview of Protection Strategies in North American Microgrid Projects," *IEEE Power & Energy Society General Meeting*, pp. 1–5, Chicago, IL, 2017.

[8] J. Subbarayan, B. Cockerham, and J. Blair, "Selective Tripping at Point of Common Coupling (PCC) Using Inverse-Time Voltage Characteristics," proceedings of the 57th Annual Minnesota Power Systems Conference, Saint Paul, MN, November 2021.

[9] G. P. Juvekar, E. Atienza, C. Kelley, and N. Malla, "Power System Contingencies to Evaluate FLISR Systems," proceedings of the 75th Annual Conference for Protective Relay Engineers, College Station, TX, March 2022.

[10] L. Booth, K. Ravikumar and C. Salo, "Implementing High-Density Coordination and Restoration Logic in the SEL-651R and SEL-651RA Recloser Controls," SEL Application Guide (AG2023-23), 2023. Available: selinc.com.

[11] W. G. Hartmann, "Implementing VVO With DER Penetration," *IEEE Power & Energy Society Innovative Smart Grid Technologies Conference (ISGT)*, Washington, D.C., 2017.

[12] J. Thorne, D. Nahay, C. Salo, J. Blair, and G. Ashokkumar, "Improving Distribution System Reliability With High-Density Coordination and Automatic System Restoration," proceedings of the 49th Annual Western Protective Relay Conference, Spokane, WA, October 2022.

[13] North American Electric Reliability Corporation, "Considerations for Power Plant and Transmission System Protection Coordination," Technical Reference Document – Revision 2, July 2015. Available: nerc.com.

[14] IEC 60076-21:2018/IEEE Std C57.15-2017, *Power Transformers – Part 21: Standard Requirements, Terminology, and Test Code for Step-Voltage Regulators.*

[15] *SEL-2431 Voltage Regulator Control Instruction Manual*. Available: selinc.com.

[16] M. V. V. S. Yalla, "Design of a New Operating Mode for Voltage Regulator Controls in a Smart Distribution System," *IEEE Rural Electric Power Conference (REPC)*, Columbus, OH, 2017.

[17] B. Rowland, J. Blair, and K. Hao, "Wireless Current Sensing for Improved Distribution Capacitor Bank Control," May 2023. Available: selinc.com.

[18] IEEE Std 1036, *IEEE Guide for the Application of Shunt Power Capacitors*, 2020.

[19] *Electrical Transmission and Distribution Reference Book*, Westinghouse Electric Corporation, 1964, Chap. 11, "Relay and Circuit-Breaker Applications," Table 13.

VII. Biographies

Shawn Shields is a power engineer in Research and Development for the distribution controls and sensors group at Schweitzer Engineering Laboratories, Inc. (SEL). He started with SEL in 2020 and has worked in the fields of power system protection, monitoring, and control. He received his BS in electrical and electronics engineering with an emphasis in electric power systems and a minor in computer science from Boise State University. He is currently working on his master's degree at the University of Idaho.

Gandhali Juvekar received her Bachelor of Technology in Electrical and Electronics Engineering from the National Institute of Technology Karnataka (NITK), India, in 2017. She received her MS in Electrical Engineering from Texas A&M University in 2019. She is currently a lead power engineer with Schweitzer Engineering Laboratories, Inc. (SEL). Her research interests include power system protection applications, time-domain quantities, geomagnetic disturbances, and distributed energy resources.

Cole Salo has a BSEE from Montana Tech. He joined Schweitzer Engineering Laboratories, Inc., (SEL) as an intern in 2008 and was then hired as a product engineer in 2009. At SEL, he has held roles supporting and developing distribution, transmission, and transformer products. He is currently a senior product engineer working in the distribution, controls, and sensors division supporting product applications along with the development of new products.

Bill Glennon is an engineering director in Research and Development (R&D) at Schweitzer Engineering Laboratories, Inc., (SEL), where he leads the teams responsible for the product development of SEL distribution protection and control, fault indicator and sensor, and wireless product lines. Bill joined SEL in 2009 working in R&D on protective relay and recloser control design, development, and support in the distribution engineering group. In 2015, Bill joined the national operations division, where he led technical sales activities for SEL in Montana and Wyoming for two years. He then served as the regional sales and service director for the Pacific Northwest U.S. and Western Canada region for four years before returning to R&D in his present role. He received his BS in electrical engineering from the Montana Tech University and is an active member of the IEEE.

20240916 • TP7180-01