Real-World Troubleshooting With Microprocessor-Based Recloser Controls

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Abstract—**Modern microprocessor-based recloser controls offer great flexibility in distribution networks. Reclosers and their controllers allow for simple, modular installations, the components of which are often treated as black boxes whose unique failure modes are misunderstood or even ignored due to their ease of replacement. This paper provides accounts of undesired operations that have occurred in real recloser installations, reveals the root cause, and offers techniques to mitigate against future failures. The paper categorizes recloser installation misoperations as single-pole tripping, reclosing, and apparent miscoordination issues. The paper recommends commissioning and maintenance practices as well as tips for troubleshooting and repairing recloser systems.**

I. INTRODUCTION

Modern microprocessor-based recloser controls offer distribution protection engineers unprecedented flexibility to develop secure and dependable protection schemes. Recloser control recording capabilities facilitate root-cause analysis of recloser responses to complex fault types and unexpected failures to reclose.

These recloser controls also offer a previously unavailable view into the operation of the attached recloser. Many recloser system failures are the result of poor commissioning, delayed maintenance, or component degradation due to weather and general mechanical wear. These failures are often left unanalyzed and are resolved by simply replacing either the control, the control cable, or the recloser. However, the powerful recording capabilities of many modern microprocessor-based recloser controls can be used to provide more targeted troubleshooting for some failures.

This paper presents problems that arise in real-world recloser installations and demonstrates the tools for troubleshooting failures and misoperations. It also highlights recommendations for users to develop their own commissioning and maintenance best practices.

II. EVENT ANALYSIS

When faults or system disturbances occur, modern microprocessor-based recloser controls can record sampled analog quantities in addition to the statuses of inputs, outputs, and internal digital bits. These records are commonly known as event records. These recloser controls can also record time-stamped changes of digital states reported in Sequence of Events (SOE) records. SOE records are used to monitor input, output, and protection element digital states as well as programmable logic bits that assert or deassert based on the

device's sequence of operations. Reference [1] describes a variety of reports in detail, explains how they can be triggered, and discusses their different data formats. These reports can be retrieved from the recloser control through local communications interfaces and are often available via remote communications, allowing centralized systems to automatically retrieve these reports [2].

The following subsections describe various real-world recloser control problems using event records and SOE records in addition to other analysis techniques. Each subsection describes and analyzes a unique circumstance.

A. Single-Pole Tripping Issues

In multigrounded-wye distribution systems, single-phase loads are typically connected to only one of the three phases. These loads are evenly distributed on each phase over the length of the distribution feeder to maintain an aggregate demand that the feeder sees as balanced. That is, on feeders that serve mostly single-phase loads, each phase serves about one-third of the customers on the feeder. A single-line-to-ground (SLG) fault is the most common fault type on such systems. Only the faulted phase must be tripped to clear SLG faults. Since only a portion of customers connected to a feeder are connected to the faulted phase, distribution utilities often improve their reliability indices with single-pole-tripping reclosers [3]. Of course, three-phase loads may also be connected to a distribution feeder, and an interruption on any phase will affect these loads. Utilities must address operational considerations, such as when to implement single-pole tripping and how utility personnel will interface with multiphase circuits that have been tripped on one or two phases.

1) When Three-Pole Tripping Is Required

The purpose of single-pole tripping is to improve reliability indices by interrupting service only on faulted phases. However, a three-phase system with only some energized phases challenges traditional work practices and protection methods and can adversely affect any attached three-phase loads.

To determine whether to use single-pole tripping on the distribution system, utilities must consider whether each individual feeder can benefit from it. If most customers attached to a feeder are multiphase loads, then interrupting a single phase serves no benefit to those customers or to the utility's reliability indices. In fact, an extended open-pole condition could even damage three-phase motor loads. For these feeders, three-pole tripping and reclosing is the best option.

If most customers attached to a feeder are single-phase loads, single-pole tripping and reclosing can improve reliability indices and reduce temporary outages for customers on healthy phases. However, a single-pole lockout can result in a prolonged unbalance that can exceed the upstream or downstream protection ground pickup. If this is a risk on a given feeder, a three-pole lockout should be applied for a permanent fault.

If a single-pole trip and lockout is employed, the utility's work is not finished when the fault is cleared. Service personnel must identify the cause of the fault and repair it before the faulted phase can be restored. If there are multiphase transformer banks downstream of the recloser that interrupt the faulted phase, the isolated phase may still be energized from the remaining phases through the transformer connections [4]. This poses a hazard to crews repairing a fault on this phase. In addition to this concern, the proximity of the faulted phase to the remaining phases creates a risk of electrical contact during the repairs. For this reason, the faulted phase must be repaired using hot-work practices, or all three phases must be interrupted to ensure that the faulted phase is de-energized and remains so throughout the repair.

Considering the repair process for most SLG faults, customers attached to the healthy phases typically still experience an outage, but the duration of the outage is less than that for a three-phase lockout. This means that the distribution utility can expect single-pole tripping to reduce the Momentary Average Interruption Frequency Index (MAIFI) and System Average Interruption Duration Index (SAIDI) metrics but may not have much influence on System Average Interruption Frequency Index (SAIFI) metrics. Reference [3] provides details for calculating these indices.

Utilities employing single-pole tripping should also consider the effects on operational safety during planned switching or energized work. The National Electric Safety Code (NESC) provides utilities with requirements for safe switching, tagging, and clearance procedures for energized and de-energized work [5]. Utilities, at a minimum, block reclosing when they perform energized work. They may also implement a faster trip characteristic to minimize arc-flash incident energy if personnel become involved with a fault or are in close proximity to an event. When these features are enabled on a single-pole tripping recloser, it is advisable to trip all three poles. This ensures that all energy sources are interrupted to protect personnel from further energy release.

There are also cases when a recloser control should convert a single-pole trip into a three-pole trip during normal system protection. Two such cases are outlined in the following subsections.

2) Faulted Phase Selection for Resistive Ground Faults

Individual phase 51 elements (i.e., 51A, 51B, and 51C) can easily determine the faulted phase for faults whose currents exceed the element pickups. Reference [3] addresses using sensitive ground protection in single-phase tripping reclosers.

Typical 51G and 51P settings in a recloser control coordinate with upstream feeder protection and downstream reclosers and fuses. There are many cases where the 51G element times out for an SLG fault before the 51P element does. In such cases, the 51G element time-out determines when the recloser should be tripped, and the 51A, 51B, or 51C element pickup determines which phase should be tripped.

Resistive ground faults can be more complicated because the available fault current may not exceed the phase pickups. This is why using ground protection is important. Reference [6] describes a proven method to select faulted impedance loops on transmission lines, where standing unbalance is very small and zero-sequence (I_0) and negative-sequence (I_2) currents primarily contain information about the fault. Distribution systems, however, can exhibit significant standing unbalance under normal load conditions. This can compromise the reliability of the faulted phase selection for low-magnitude faults, where I_0 and I_2 currents may be heavily influenced by load. For this reason, if a phase element is not picked up when a 51G element times out, it is best to trip all three phases.

Fig. 1 represents an extreme but realistic case of such a fault. The pre-fault steady-state load is unbalanced, but the 51G pickup is set above this unbalance. Once the resistive fault occurs on Phase A, the fault current is still below the 51A phase pickup, but the resulting unbalance generates enough ground current (I_G) to exceed the 51G pickup. This is shown when 51G1 asserts. The I_0 and I_2 currents are separated by more than 60 degrees, even though a typical SLG fault on Phase A should generate I_0 and I_2 currents nearly in phase with each other.
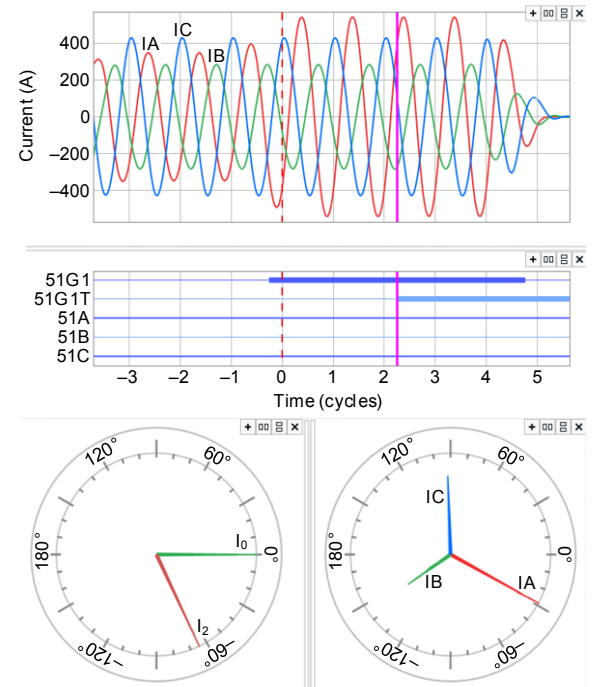

Fig. 1. Resistive ground fault on an unbalanced feeder. The phasor diagrams align with the solid, vertical line in the oscillography report.

Reference [3] discusses the logic that is used to reliably select phases for tripping to clear ground faults (see Fig. 2). For resistive ground faults with currents that do not exceed a phase pickup, it is best to trip all three phases to ensure that the fault is cleared.
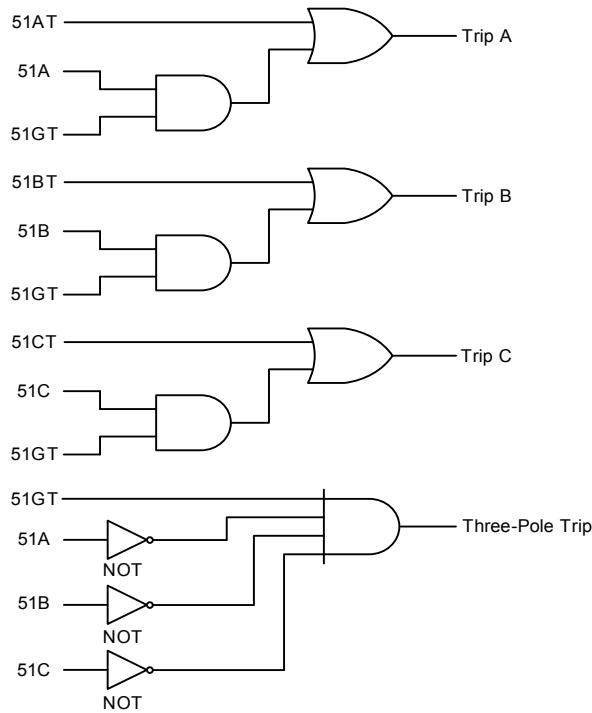

Fig. 2.   Phase trip selection logic for ground faults.

3) Tripping the Wrong Phase

Some distribution reclosers provide independently operated poles that allow only faulted phases to be interrupted. All recloser controls monitor current on each phase independently, but recloser controls that support single-pole tripping and reclosing must additionally monitor 52A auxiliary contact states and provide trip and close signals for each independent pole. This means that correct phasing must be applied in the current transformer (CT), the 52A auxiliary contact, and the trip and close circuits. If the phase relationships in all three circuits are not in total agreement, there is a risk that the wrong pole could be tripped for an SLG fault.

Recloser and recloser control manufacturers can work together to ensure compatibility. Both parties can agree to use a control cable pinout that ensures that the CT, the 52A auxiliary contact, and the trip and close circuits from each pole of the recloser are connected in matched sets to the recloser control's available connections for each pole. This greatly reduces the risk of a fault observed on one phase leading to the trip of a different phase. However, real-world recloser control cables and junction boxes may be miswired. Appropriate commissioning steps must be followed to identify and correct these instances, and single-pole tripping protection schemes must provide a dependable response if the wrong pole is tripped.

The following criteria need to be addressed when setting up a single-pole recloser:

- The recloser control CT input phasing should match the system phasing. This can be achieved through connections to the recloser control or by assigning phase designations to each channel. While this is not critical for most protection tasks, it does make fault targeting easier to interpret and keeps metering and energy quantities correct.
- If changes have been implemented to reassign phase designations for the recloser control CT inputs, the 52A auxiliary contact, and the trip and close circuits must be updated to match.
- The recloser bypass switch and line and load disconnect switches should be closed during commissioning so that the recloser can carry load. Each pole should be tripped and closed individually to confirm that the expected phase is physically operating, interrupting load current, and updating its 52A auxiliary contact.

Fig. 3 shows an example of what happens when these commissioning steps are not implemented. Phases A and C are involved in the fault, as shown in the current waveform. The fault magnitude is around 1,200 A root-mean-square (rms), or 1,500 A peak. There is also voltage depression on these phases, as shown in the voltage waveform.
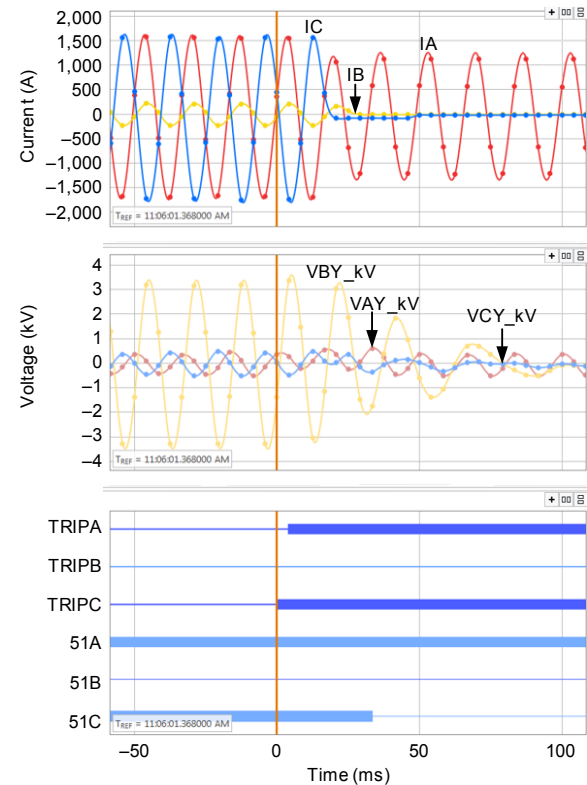

Fig. 3.   Incorrect pole trip for a multiphase fault.

The single-pole recloser should trip Poles A and C, and the event record shows that TRIPA and TRIPC were issued from the recloser control. However, the current waveform dissipates to zero on Phases B and C when a trip is issued. Furthermore, the current threshold pickup for Phase A remains asserted (51A) and is directly related to the continuous fault current still present on Phase A. Thus, Pole B was opened when Pole A should have been opened based on the initial fault type. This indicates that TRIPA was issued to the Phase B pole. Further investigation of this event revealed that TRIPA and TRIPB were erroneously mapped to the Pole B and Pole A output contacts, respectively. This type of error can also occur if a control cable is wired incorrectly.

The custom logic capabilities of many modern microprocessor-based recloser controls allow users to build dependable backup schemes that ensure the fault is interrupted. A simple breaker failure scheme can be written for each pole that declares failure if an overcurrent remains for some duration (typically more than 8 cycles) after the trip. If a pole's breaker failure scheme operates, the backup scheme can be applied to a three-phase trip. If all three phases are tripped as a backup operation, there is no question that the faulted phase will be interrupted.

Strict commissioning principles help to mitigate events like in Fig. 3. Basic settings checks are vital to achieving correct trip and close operations.

B. Reclosing Issues

A distribution recloser's primary function is to detect faults and trip to clear them. Its secondary purpose is to automatically reclose to avoid an extended outage for a temporary fault. Thus, a recloser failing to reclose is not nearly as detrimental as a false trip.

It is imperative that reclosing not occur when the recloser is manually tripped or if the recloser is tripped while personnel are performing energized work downstream. Supervision practices are necessary to ensure reclosing only occurs when it is safe and beneficial. However, when reclosing fails during normal operation it is usually due to a failure to satisfy supervisory conditions.

Supervision practices can vary by manufacturer, but there are typically three supervisory functions in most reclosing schemes: reclose initiation, reclose supervision (evaluated at the end of each open interval for each reclose operation), and reclose cancel (commonly referred to as drive to lockout).

Reclose initiation occurs when the recloser opens. At this time, the recloser control must determine if reclosing should be attempted. Typically, reclose initiation asserts only for certain protective trips. Some recloser controls employ reclose initiation supervision to block the reclose initiation unless the recloser is closed or the recloser control is already in a reclosing cycle (in that case, the recloser status indication may be too slow for reliable supervision). This ensures that reclosing is not enabled for a trip developed when the recloser is open, which would indicate a flashover within or across the recloser bushings.

If reclosing initiation is satisfied, the recloser control will time through the first open interval once the recloser is open. When the open interval has expired, reclose supervision ensures that all conditions required to support a reclose, and more importantly a subsequent trip, are satisfied.

Reclose cancel can be employed in a recloser control to drive the recloser into an immediate lockout condition. Any input used to drive a manual trip can also be used as an input for this function to ensure that automatic reclosing does not occur for a manual trip. Reclose cancel is also often used to manually disable reclosing when other work processes require it. For instance, when line crews must build or repair a line while it is energized, they will disable reclosing in case personnel become involved with a fault. It is also common to disable reclosing during switching in case a trip occurs due to load rebalancing, inrush, or faults. Additionally, it can be desirable to reclose cancel if certain protective elements assert. In feeder protection, it is common to block reclosing for faults above a high current threshold in order to prevent continued excessive through-fault energy or to prevent closing onto a fault that may be located in an underground cable exiting the substation. Reference [7] describes a wireless protection sensor system that can also be used as a reclose cancel input to block reclosing for faults in underground cable facilities elsewhere on the feeder.

1) Determining the Cause of Lockout

There are multiple layers of supervision that must be met to ensure that a reclose occurs, so a reclose failure can be difficult to troubleshoot. It can also be difficult to know where to start. However, with some understanding of typical reclosing nomenclature and knowledge of recloser control supervision requirements, the source of the failure can be determined. The three states for a typical reclosing function are reset, cycle, and lockout.

The reclosing function is in its reset state when the recloser is closed and there is no fault activity in recent memory. In this state, the recloser control simply watches for a disturbance. If a reclose initiation occurs when the recloser opens, the reclosing function moves into its cycle state.

During the cycle state, the reclosing function leaves the recloser in the open position for the duration of its set open interval. When the open interval expires, the recloser control attempts to reclose. Once the recloser is closed again, the reclosing function waits the duration of its reset time to verify whether a new reclose initiation (i.e., another trip, because the fault is still on the line) occurs. If no new reclose initiation occurs during the reset time, the reclosing function goes back into its reset state. However, if a new reclose initiation does occur within the reset time, the reclosing function remains in the cycle state, times the next open interval, and then issues a reclose. It continues in the cycle state, running the reset timer after each successful close, until the reset timer is satisfied or until the number of configured reclose operations has occurred. Once there are no more reclose operations, the reclosing function moves into its lockout state where it leaves the recloser open until it is manually closed.

Given this sequence of reclosing logic, the SOE record becomes an invaluable resource. When the SOE record is configured to capture the reset, cycle, and lockout states with time stamps, the time intervals between these states indicate whether a reclosing failure occurred due to reclose initiation, reclose supervision, or reclose cancel.

When reclose initiation fails, the reclosing function goes directly from the reset state into the lockout state, and no reclose is attempted. This is rarely the failure mode for a distribution recloser, since the source of the protective trip driving reclose initiation is internal to the same recloser control.

When reclose supervision fails, the reclosing function has already entered the cycle state and has stayed there for at least the time of its first open interval. If there is an additional time window set to wait for reclose supervision to be satisfied, the recloser control stays in the cycle state for the open interval plus the reclose supervision time window.

The reclosing function in a recloser control goes into the lockout state the moment a reclose cancel occurs. For this reason, if the SOE record reveals that the cycle state lasted less than the duration of an open interval, the reclose cancel function becomes suspect. In most distribution recloser applications, if the reclosing function state goes directly from reset into lockout, the reclose cancel function is the culprit.

The following subsections provide real-world examples of reclose failures and trace the cause of these failures to the supervisory function inputs.

2) Reclose Initiate Failure

A recloser control reclosing function must go into the lockout state any time the recloser is opened manually. While most manual operations are carried out through the recloser control human-machine interface, it is also possible to trip a recloser using the manual operating handle (also referred to as the yellow handle). The recloser control can then only observe the 52A auxiliary contact opening. The recloser control must recognize this as a manual trip when not accompanied by a reclose initiation and must drive the reclosing function into the lockout state. However, this also means that a 52A auxiliary contact performing unreliably can lead to a reclose initiation failure.

Fig. 4 shows a reclosing function that goes into the lockout state prematurely due to a chattering 52A auxiliary contact. At the beginning of this event record, the reclosing function is in the cycle state (79CY). This event begins at the end of an open interval when the recloser control issues a close command (CLOSE). The resulting current waveforms and the 52A status indicate that the recloser has closed. Because the fault is still present, the 51P1 and 51G1 elements pick up and begin timing immediately. In the meantime, 52A drops out momentarily. This may be caused by a ripple in the dc supply for this contact or by a failing contact or connection to the contact. Sometimes internal breakdown in the potting compound is experienced on the rear of the pin connector internal to the recloser tank. This leads to a chattering 52A auxiliary contact even though it is perfectly fine within the tank.

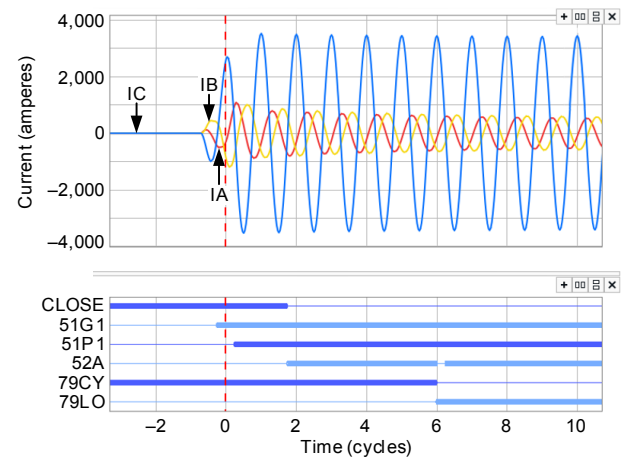Fig. 5 shows the path of the internal wiring run to the rear of the potted pin connector.

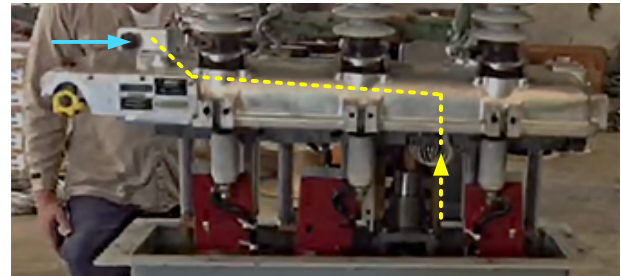Fig. 4. Reclose initiation failure due to a chattering 52A auxiliary contact.

Fig. 5. Internal wiring leads to the rear of the pin connector internal to the recloser tank. The blue arrow indicates the pin connector, and the dashed yellow line and arrow indicate the wiring run coming from the 52A auxiliary contact.

As a result, the reclosing function sees 52A drop out, indicating an open recloser, without a simultaneous reclose initiation (TRIP). Therefore, when 52A first drops out, the reclosing function goes into the lockout state (79LO). When the recloser control trips for this fault (outside of the event window), it will be in the lockout state already and remain open with no attempt to automatically reclose.

Even though a premature lockout is a direct result of this failure, a microprocessor-based recloser control can detect a chattering 52A contact before a premature lockout occurs. The 52A state can be monitored in an SOE report for regular analysis. Better yet, if the recloser control supports custom logic, a condition statement can be written to set off an alarm for a chattering 52A or for when the 52A state indicates that the recloser is open while carrying load current. If the recloser control is monitored remotely via supervisory control and data acquisition (SCADA), personnel can respond immediately to correct this before a fault occurs.

3) Reclose Cancel

Modern microprocessor-based recloser controls are tremendously flexible in terms of logical parameters. For example, they can manually enable or disable reclosing by using a nonvolatile digital latch or maintained panel switch that is used in the reclose cancel function. If reclosing is disabled when a fault occurs, the recloser control issues a trip and the recloser goes directly into the lockout state, regardless of the number of reclose shots configured on the device.

Hot-line tag is a feature used by most utilities to disable reclosing and manual closing operations. While this feature is defined by some manufacturers, there is no industry standard governing hot-line tag operation. Typically, automatic reclosing is disabled whenever hot-line tag is enabled. Therefore, the recloser goes into the lockout state when tripped if hot-line tag is enabled (typically for energized line work) or if reclosing is disabled (typically for switching).

With one-shot reclosing enabled and reclosing manually enabled, a normal reclosing sequence is expected, as shown in Fig. 6. The recloser control issues a trip signal based on an instantaneous element (50P1T). The trip signal is the result of the instantaneous overcurrent pickup (TRIP3P). The reclosing state changes from reset (79RS3P) to cycle (79CY3P) and is the starting point of the first open interval timer. After the first open interval timer expires, the first attempt on closing (i.e., the first shot) is executed (SH13P). Then, the close signal (CLOSE3P) is sent to the recloser, and the recloser reports a successful close (52A3P). At this point, the fault still exists on the distribution network, therefore, the instantaneous overcurrent element executes a trip signal again (50P1T). The result is a reclosing state change into lockout (79LO3P) due to the reclose initiation (TRIP3P) that occurred on the last shot.

```
06/09/2018  16:48:09.872  51P      Asserted
06/09/2018  16:48:09.880  50P1T    Asserted
06/09/2018  16:48:09.880  TRIP3P   Asserted
06/09/2018  16:48:09.880  79CY3P   Asserted
06/09/2018  16:48:09.880  79RS3P   Deasserted
06/09/2018  16:48:09.918  52A3P    Deasserted
06/09/2018  16:48:10.314  51PT     Asserted
06/09/2018  16:48:10.905  50P1T    Deasserted
06/09/2018  16:48:10.914  51P      Deasserted
06/09/2018  16:48:10.930  51PT     Deasserted
06/09/2018  16:48:10.930  TRIP3P   Deasserted
06/09/2018  16:48:14.913  SH13P    Asserted
06/09/2018  16:48:14.913  SH03P    Deasserted
06/09/2018  16:48:14.913  CLOSE3P  Asserted
06/09/2018  16:48:14.968  52A3P    Asserted
06/09/2018  16:48:14.968  CLOSE3P  Deasserted
06/09/2018  16:48:14.972  51P      Asserted
06/09/2018  16:48:14.972  50P1T    Asserted
06/09/2018  16:48:14.972  TRIP3P   Asserted
06/09/2018  16:48:14.972  79LO3P   Asserted
06/09/2018  16:48:14.972  79CY3P   Deasserted
06/09/2018  16:48:15.072  51P      Deasserted
06/09/2018  16:48:15.072  50P1T    Deasserted
06/09/2018  16:48:15.080  52A3P    Deasserted
06/09/2018  16:48:15.638  TRIP3P   Deasserted
```

Fig. 6.   SOE record showing a successful reclose attempt and lockout of a one-shot-to-lockout programmed recloser control.

With one-shot reclosing enabled but reclosing manually disabled, the recloser should go directly into the lockout state without timing the first open interval. Fig. 7 shows that an SLG fault occurred on Phase A. The phase time-overcurrent element picks up and trips (51PT) via the trip equation (TRIP3P). The recloser poles open (shown when Phase A current diminishes to zero) when TRIP3P asserts. More importantly, the recloser control goes directly from the reset state (79RS3P) into the lockout state (79LO3P), thus bypassing the cycle state at the point where TRIP3P asserts.
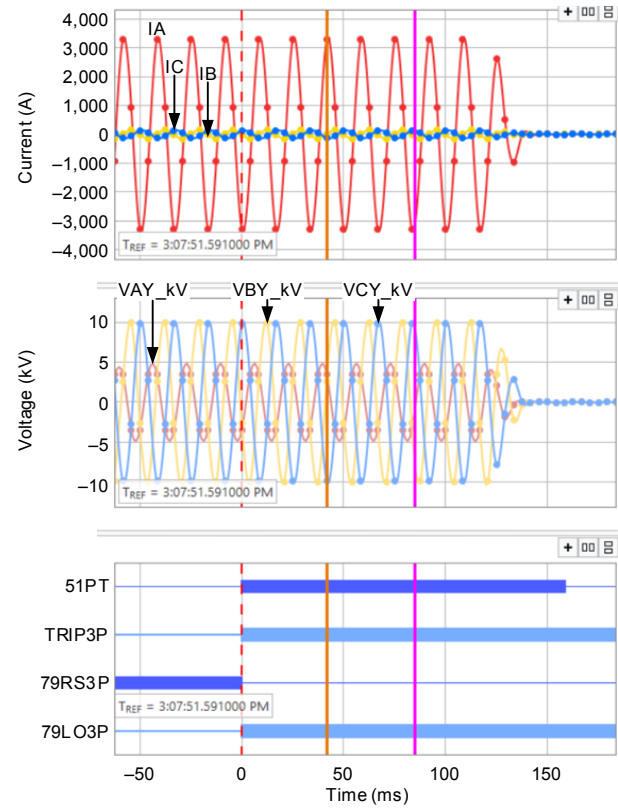

Fig. 7.   Typical recloser control goes into the lockout state when reclose enabled is off.

It is also possible to cancel reclose during the cycle state. Fig. 8 shows that the instantaneous element 50P2T is used to trip the recloser. At the point when the trip (TRIP3P) occurs, the recloser control goes from the reset state (79RS3P) into the cycle state (79CY3P). When the RMB1A bit asserts, it drives the recloser into the lockout state shortly after the trip is issued. RMB1A is a communication bit that indicates the fault was observed by a wireless protection sensor in an underground trunk section downstream (a fault location that is undesirable for reclosing).
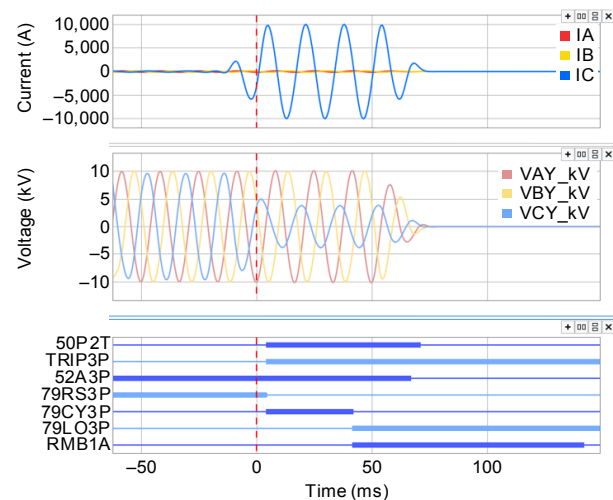

Fig. 8.   Wireless protection sensor actively drives a recloser into the lockout state during the cycle state.

C. Apparent Miscoordination

Time-overcurrent coordination is a simple task on the surface, especially with modern coordination software. It is possible to plot the proposed time-current characteristic of the time-overcurrent devices in series and adjust the curve and related settings until there is an adequate clearance between the curves. However, this approach only recognizes the existence of a single bolted fault, while the distribution system can be far more dynamic. Faults can evolve or migrate from one phase to another. They can be intermittent and can sometimes cause new faults. These faults challenge simple time-overcurrent coordination and can lead to nonselective trips. The following subsections analyze examples of and provide solutions for nonselective trips for out-of-zone faults caused by dynamic conditions.

1) Conductor Slap

Reference [8] provides a thorough analysis of a conductor slap event, where a fault downstream of one recloser generated enough current to create opposing magnetic fields on adjacent conductors upstream of the recloser, forcing them into motion. The adjacent conductors eventually made contact because of this motion and developed a new, temporary phase-to-phase fault that the substation feeder breaker had to clear.

As described in [8], these faults can be confusing for field personnel who find that the feeder breaker has tripped, potentially into the lockout state, yet discover the original fault downstream of a recloser (see Fig. 9). Personnel assume that the recloser and the feeder breaker were not coordinated when both the feeder and recloser were actually timing to trip for faults in their zones of protection.
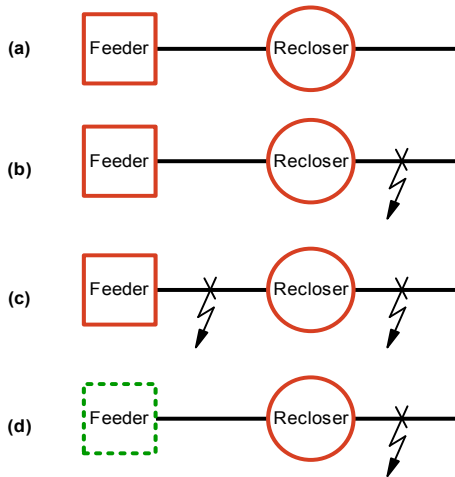

Fig. 9.   Sequence of a typical conductor slap event. (a) Feeder and recloser are both closed and coordinated. (b) Fault strikes downstream of the recloser, and the recloser begins timing for the fault. (c) Fault currents cause the conductors between the feeder and recloser to swing apart and back together, leading to a new, temporary phase-to-phase fault in the feeder zone. (d) The new fault has a higher magnitude, typically causing the feeder to trip before the recloser does.

Modern microprocessor-based recloser controls and feeder relays with recording capabilities (like SOE records and event records) can reveal this type of behavior. Fig. 10 shows a list of event records from a feeder relay that tripped for a conductor slap event. Event 6 began as a BC fault with a magnitude of

2,161 A. This is the original out-of-section fault. After this, new faults developed between Phases A and B, and with each fault, the magnitude increased. Each of these events represents unique locations on the feeder where the Phase A and B conductors made contact (i.e., there was a conductor slap). The recloser control finally tripped for one of these instances in Event 1, where a "T" was added to the event type.

```
FEEDER RELAY                        Date: 11/28/11
DISTRIBUTION

#    DATE      TIME         EVENT   LOCAT  CURR  FREQ

1  11/26/11 20:31:35.999  ABG T    1.73  3809 59.94
2  11/26/11 20:31:35.799  ABG      1.72  3809 60.06
3  11/26/11 20:31:35.046  AB       1.62  3602 60.01
4  11/26/11 20:31:33.896  AB       3.88  2995 60.01
5  11/26/11 20:31:32.313  AB       6.27  2546 60.00
6  11/26/11 20:31:32.005  BC      11.33  2161 60.00
```

Fig. 10.   Event record shows conductor slap at multiple locations.

The utility that experienced this trip used the fault magnitudes to find each of these locations and documented the evidence as pitting and beading of the aluminum on the surface of the conductor where the phases made contact, as in [8]. The two phases that made contact were physically adjacent and on the same side of the crossarm, which explains why Phases A and B made contact even though Phases B and C experienced the original fault. This problem can be prevented by ensuring adequate spacing between phases, shortening span lengths, or installing spacers between the conductors. Reference [8] also recommends logic for microprocessor-based recloser controls to recognize this condition and go directly into the lockout state to prevent further upstream conductor slap instances for in-zone faults.

2) Ratcheting and Electromechanical Reset

An induction disk relay used for time-overcurrent (51) protection exhibits an operating time delay that is inversely proportional to the measured current as a multiple of the relay's set pickup. However, the braking forces used to control the speed of the disk's rotation toward its stationary contact also introduce a reset time delay. This reset time is a necessary component of an induction disk relay due to its physical design. But, in a microprocessor-based recloser control, an inverse-time overcurrent element can be reset instantaneously.

Many microprocessor-based recloser controls offer the option to emulate the reset characteristic of an induction disk relay or to reset inverse-time overcurrent elements within a short delay after current drops below the minimum pickup. When choosing a reset method, the most important consideration is ensuring that there is coordination with other 51 elements upstream and downstream.

Instantaneously resetting the 51 element ensures the best chance of coordinating with downstream devices, some of which may also reset instantaneously. This is an important consideration in reclosing schemes, where each device can be subjected to the same fault more than once within a short time. However, if there is an induction disk relay (or a digital relay emulating induction disk reset) upstream of an instantaneously

reset device, the upstream relay may not get a chance to fully reset before the fault current returns. This is often referred to as ratcheting, and the effect of this is shown in Fig. 11, where the relay with an electromechanical reset characteristic eventually times out, even though the fault is cleared each time before the published time-out for the fault.
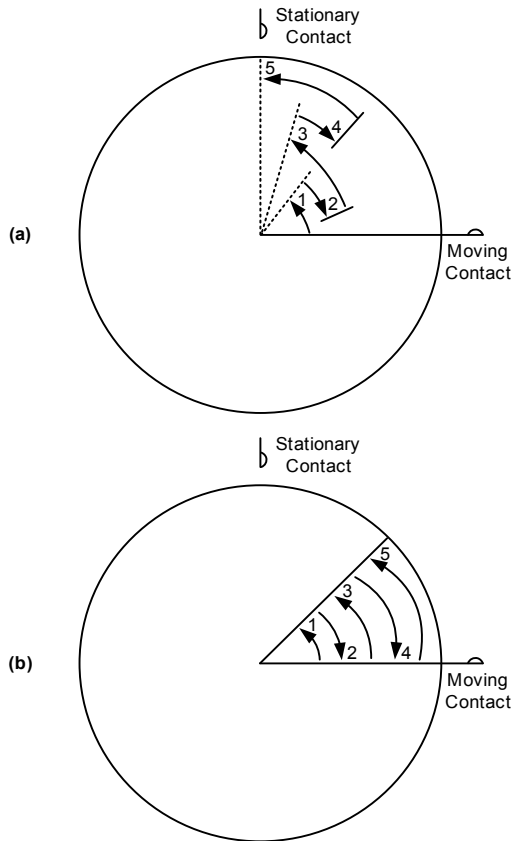

Fig. 11. Induction disk behavior of the digital 51 element during a reclose sequence. (a) Induction disk model emulating electromechanical reset. (b) Induction disk model with instantaneous reset.

Fig. 12 also demonstrates a ratcheting event where both relays are subjected to an intermittent fault. Relay 2 does not get a chance to fully reset (2:51P2R) while Relay 1 does fully reset (1:51AR) before the fault occurs again. Therefore, Relay 2 times out to trip while Relay 1 does not. If Relay 2 is upstream of Relay 1, it could incorrectly trip for intermittent faults downstream of Relay 1. Ratcheting can be avoided in this example by setting both relays to use the same technique for the 51 element reset.

When the upstream relay must use an electromechanical reset, the downstream relay should too. When an electromechanical reset is not available in the downstream device (like with hydraulic reclosers and some legacy electronic relays), reclosing open intervals should be long enough to allow

the upstream relay time to reset during the open interval. This does not prevent miscoordination for intermittent faults but does prevent miscoordination for bolted faults during a reclose sequence.
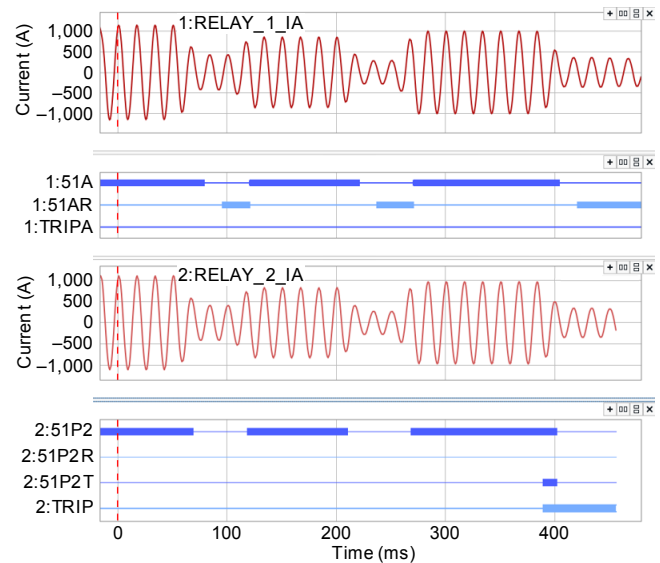

Fig. 12. Analog and digital traces for Relay 1 (instantaneous reset) and Relay 2 (emulated electromechanical reset).

3) Evolving Faults and Single-Phase Sectionalizers on Multiphase Lines

When a sectionalizer measures a current that exceeds a fault detector pickup and subsequently drops to zero, it recognizes this as a fault downstream that has been cleared by a recloser upstream. For instances like this, a counter is incremented. If the counter reaches a set threshold before a reset timer expires, the sectionalizer opens to isolate the faulted line section downstream. Sectionalizers must be set to trip on a count that allows the upstream recloser at least one more reclose operation.

Many utilities employ single-phase, cutout-style sectionalizers on their distribution systems. Their small size and cutout-mounted form factor allow them to replace fuses with little effort. They are also easy to coordinate with other reclosers and fuses because they use a counter instead of a time-overcurrent characteristic to selectively isolate faults in their zone. However, evolving faults can challenge a protection system that combines single-phase sectionalizers on a multiphase lateral with three-phase tripping and reclosing upstream. This is because the sectionalizers on each phase contain their own independent counters. The recloser can ultimately lock out for a fault that is in the sectionalizers' zone of protection, as shown in Fig. 13. In this example, the Phase B sectionalizer does not start counting when the recloser starts counting, so the two are no longer coordinated.
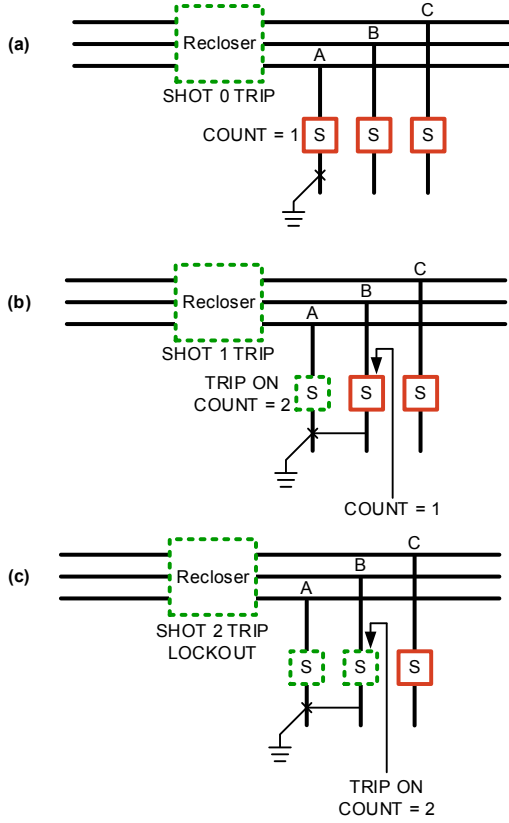
Fig. 13.   Typical evolving fault sequence for the three-phase tripping recloser with single-phase sectionalizers downstream. The recloser is set for three operations to lock out, so the sectionalizers are set to trip on their second count. (a) The recloser trips for an A-phase-to-ground (AG) fault, and the Phase A sectionalizer increments its counter. (b) The fault evolves into an A-phase-to-B-phase-to-ground (ABG) fault, and the recloser trips again. The Phase A sectionalizer increments its counter and trips, and the Phase B sectionalizer increments its counter. (c) The recloser trips to lock out for an apparent B-phase-to-ground (BG) fault, and the Phase B sectionalizer increments its count and trips.

Fig. 13 shows that it is best to apply a three-phase sectionalizer on multiphase laterals when three-phase tripping is applied upstream. Single-phase sectionalizers can still be used on single-phase laterals. They should only be used on multiphase laterals if the upstream protection applies a single-phase tripping and reclosing scheme where each phase operates independently. If a single shot counter is used for all three phases or if the shot counters on each phase are synchronized, the potential for miscoordination with single-phase sectionalizers on a multiphase lateral still exists for evolving faults.

III.   Commissioning Practices

The root cause of many of the undesired operations previously discussed could have been detected during commissioning. A comprehensive commissioning strategy is key to successful distribution line recloser installations. Reference [9] provides a methodical approach for commissioning microprocessor-based relays in substations and power stations. Fig. 14 applies this concept to recloser installations and indicates a simple but effective procedure for commissioning reclosers with microprocessor-based recloser controls.

After receiving a recloser controller with factory-default settings, settings engineers must develop settings and logic based on system coordination studies and company operating procedures and design drawings. Then, these settings are uploaded to the recloser control. The recloser control with these user-defined settings is commissioned as shown in Fig. 14. By recognizing the knowledge and equipment needed for each step, this procedure can be scaled from individual installations to widespread system upgrades. Settings engineers, technicians, and line crews must work together throughout this process to be successful.
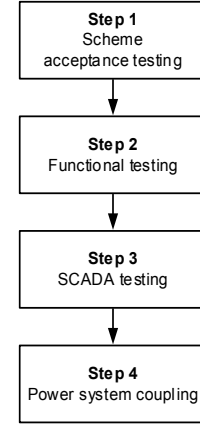

Fig. 14.   Recommended basic flow sequence for best commissioning practices.

The steps shown in Fig. 14 are detailed in the following subsections.

A.   Scheme Acceptance Testing

Microprocessor-based recloser controls perform self-check tests to confirm acceptable analog and digital subsystem operation. Their element pickups and characteristics do not drift over time the way their electromechanical and hydraulic counterparts do. Testing individual protection element pickups and time-outs in a microprocessor-based recloser control offers little advantage over a simple meter check. If the recloser control has passed its continuous self-check tests and if it measures known currents and voltages correctly, then its protection elements will respond predictably.

Secondary injection testing is a practical way to verify analog system functions and can simulate specific system load and fault conditions to verify scheme operation, including supervision functions. The expected operation with secondary injection testing thus simulates real-world events as if the device were connected to the power system.

Some secondary injection test sets are available with pin-compatible interfaces that connect to a recloser control in place of the recloser control cable (see Fig. 15). Currents and voltages can then be injected to verify metering, protection element pickups and timing, and reclosing supervision, as well as any other custom logic that the settings engineer may have implemented. Such test sets can also simulate recloser auxiliary contact states and respond to trip and close signals from the recloser control. This allows for comprehensive protection and automation scheme testing for the recloser control.
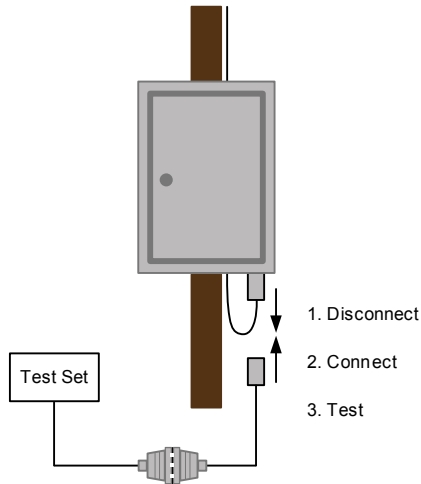
Fig. 15.   Typical test set interface connectivity to a recloser control.

Utilities that take advantage of the custom logic of microprocessor-based recloser controls typically develop a standard scheme for all of their installations (where only 51 and 79 element settings are unique to each installation). Secondary injection testing is imperative during protection scheme development so that protection scheme and supervision responses to complex cases, such as those presented in this paper, can be modeled. All custom logic, such as pushbutton functions and protection or reclosing element supervision, should be tested. Settings engineers typically test these in a laboratory or office. Once the standard scheme has been developed and tested to the utility's satisfaction using a specific recloser control model and firmware, this detailed testing does not then need to be repeated for each recloser control of the same model with the same firmware and settings scheme.

B. Functional Testing

Once a settings scheme has been tested and accepted for use, recloser controls can be loaded with it and connected to a recloser installed in the field. The recloser, control cable, and recloser control must be tested together for proper operation as a system.

The commissioning team should test all recloser control pushbuttons to confirm their physical integrity. This involves pressing the pushbuttons and observing the appropriate feedback on the recloser control front panel or confirming the attached recloser's response. The team should also perform a lamp test to confirm that all front-panel indicators operate properly.

To confirm proper operation of the recloser, control cable, and recloser control as a system, the commissioning team should issue manual trip and close commands at the recloser control while monitoring the recloser auxiliary contact state to confirm that the control circuitry functions correctly and is connected properly. The yellow handle should be pulled down to confirm that it mechanically trips the recloser and that the recloser control properly detects its state. A manual close should be attempted to confirm that closing is blocked when the yellow handle is down. These checks must be performed on each pole individually for single-pole tripping reclosers. The commissioning team should note whether the correct pole

operates and reports the expected auxiliary and yellow handle state changes for each test.

The recloser should be connected to the primary power system with closed line and load disconnect switches and closed bypass switches (which should already be the case in a new recloser installation; see Fig. 16). Then, the recloser should be closed so that it shares feeder load current with the bypass switch. This way, the recloser can provide secondary currents (and voltages, if using bushing voltage screens or potential transformers) for a meter test in the recloser control. This meter test confirms that the recloser control measures these quantities accurately and can, therefore, respond to faults accurately. It also confirms the proper CT ratio selection in reclosers with multiratio CTs and the expected phase connections.
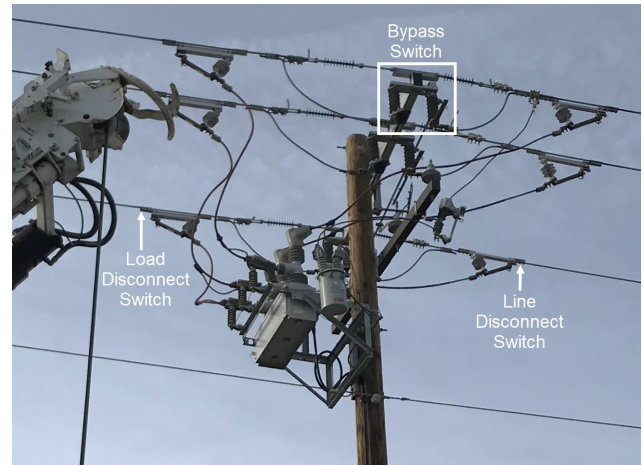

Fig. 16.   Typical recloser pole framing that shows line and load disconnect switches that isolate the recloser and a bypass switch that carries feeder load when the recloser is out of service.

C. SCADA Testing

If the recloser control is connected to a SCADA system, then a point checkout must also be performed. All digital status points that the SCADA system monitors must be forced to asserted and deasserted states, and the SCADA operators must confirm that the expected state for each individual point occurs. Next, all control commands that the SCADA system issues to the recloser control must be tested, and the commissioning team must confirm that the expected recloser control response occurs. Any supervision used for remote commands should also be tested. Finally, SCADA operators must confirm the accuracy and scaling of analog measurements sent to the SCADA system.

D. Power System Coupling

After all testing has been carried out, settings have been verified, and the installation operates as intended, the recloser can be coupled to the power system in accordance with the users' operating procedure.

IV.   Maintenance Practices

Reclosers are maintained according to company policies and schedules, which vary throughout the industry. Some equipment requires maintenance at more frequent intervals because of mechanical moving parts or the age of the

equipment. Some recloser designs are easier to rebuild than replace and vice versa. Maintenance can typically be performed on reclosers without hindering power supply to customers by closing the bypass switches.

The following are common failures due to the lack of maintenance:

- Oil leaks on the recloser gasket seals.
- Slower than normal trip and close operation.
- Degraded insulation (can lead to internal faults).
- Tracking on previously damaged or contaminated bushings.
- Basic insulation level failures due to damaged lightning arresters.
- Water intrusion in the recloser control cable.
- Recloser control ac power loss.
- Recloser control battery failure.

Visual inspection, functional testing, and preventative maintenance are three periodic maintenance categories for reclosers and recloser controls.

A. Visual Inspections

Regular visual inspections are the only way to catch some issues that degrade recloser performance over time. Visual inspections are noninvasive and can be carried out with the recloser in service. Many utilities carry out visual inspections annually or biannually. An inspector should:

- Check for oil leaks in oil-filled reclosers.
- Check for corrosion on all cables and cable connections at the recloser and recloser control.
- Check for damage, pinching, or kinking along the length of all cables.
- Check the antenna alignment and condition, if wireless communications are present.
- Verify grounding connections per installation design.
- Inspect bushings and insulators for damage or signs of tracking.
- Check for signs of animal presence, such as nests, waste, and carcasses.
- Confirm that animal guards are whole and properly installed.
- Confirm that tank-mounted lightning arresters are whole and properly grounded.
- Inspect pole framing and brackets for structural integrity.
- Confirm that recloser controls have healthy indications.
- Perform a lamp test to confirm that all indicating lamps are functional.
- Assess the battery age, and compare it with the expected replacement interval.

B. Functional Testing

Functional testing should also be carried out regularly to ensure that the entire recloser system installation still performs as expected. A functional test should include:

- Battery load discharge tests.
- AC power supply to recloser control checks.
- Manual trip and close to check open and close operation.
- SCADA control and indication.
- Metering checks to verify voltage and current measurements.
- Auxiliary equipment (such as radios, modems, or automation controllers) status checks.

C. Preventative Maintenance

Preventative maintenance is scheduled to replace or refurbish parts or materials with finite life expectancies before they fail. Modern recloser designs eliminate maintenance as much as possible, favoring replacement over repair. However, the following maintenance items must still be considered for electronic reclosers:

- Replace recloser control battery (3- to 6-year intervals, depending on the battery and charger design and environment).
- Flush and replace oil in oil-filled reclosers.
- Inspect and repair under-oil interrupting contacts when present.

With modern microprocessor-based recloser controls, many maintenance tasks can be automated, and the required data can be recorded during live operation. This allows the functional tests to be completed without taking the recloser out of service and without manual intervention.

For example, protective trips and manual local and remote SCADA operations caused by live switching can be recorded and used instead of a scheduled functional test. Metering values are constantly updated and can be compared with other meter points to confirm the proper measurements. Most auxiliary equipment used with recloser controls can report its health with an output contact wired to an input on the recloser control, where its state can be recorded.

Preventative maintenance can be scheduled based on operational data rather than elapsed time. For instance, a recloser control can perform a battery load discharge test at regular intervals, and the results can be recorded. Batteries can then be replaced when a failed test occurs rather than on a scheduled calendar date. Breaker wear monitoring can also assist with scheduling preventative maintenance.

Table I, which is based on ANSI C37.61-1973, indicates the settings required to successfully populate and enable the breaker wear monitoring on typical microprocessor-based recloser controls. Close/open operations set point (COSP) 1, 2, and 3 are the number of trip operations the interrupter can

withstand at the associated currents (kiloampere set point [KASP] 1, 2, and 3). With the breaker wear monitoring function enabled, the recloser control can send an alarm to indicate that breaker wear has exceeded a preset threshold, and utilities can immediately schedule oil and contact maintenance rather than waiting for a scheduled calendar date.

TABLE I
RECOMMENDED BREAKER MONITOR SETTINGS
FOR COMMON THREE-POLE RECLOSERS

Recloser Model	Recloser Type	Interrupt Rating (A primary)	Settings			
			COSP1	COSP2 COSP3	KASP1	KASP2 KASP3
A	Oil	6,000	10,000	20	0.10	6
B	Oil	12,000 (at 4.8 kV)	10,000	20	0.19	12
C	Oil	10,000 (at 14.4 kV)	10,000	20	0.16	10
D	Vacuum	12,000	10,000	80	0.48	12
E	Oil	8,000	10,000	20	0.13	8
F	Vacuum	16,000	10,000	80	0.64	16
G	Vacuum	20,000	10,000	80	0.80	20
H	Vacuum	12,500	10,000	2,510 64	1.25	2 12.5
I	Vacuum	12,000	10,000	100	1.25	12

V. TROUBLESHOOTING PRACTICES

The following tools and reports help provide a methodical approach to troubleshooting specific issues:

- SOE records track when specific digital bits assert and deassert during operation.
- Event records are a snapshot of the power system at a given time, including currents and voltages together with digital bit assertions for a predefined number of cycles.
- Metering provides instantaneous and rms values of currents and voltages, typically along with power, energy, demand, and harmonics. These values can be viewed with the recloser control human-machine interface or through a PC interface.
- Digital multimeters measure secondary currents and voltages, control circuit voltages, cable pin continuity, and circuit resistance. These measurements can identify connectivity failures, such as shorted pins in a cable or a failed connector in a harness.
- Scopemeters can help verify trip and close output pulses.
- Instruction manuals assist with tracing circuits and recloser control logic.
- Spare recloser controls and cables can help identify the failed component through a process of elimination and better target troubleshooting efforts.
- A robust standard for recloser control settings and devices makes it easy for a few spare recloser controls to support an entire fleet of reclosers.

There are many examples in the preceding sections of how SOE and event record data from microprocessor recloser controls can be used to troubleshoot various failures. However, some hardware failures are not as simple as they appear. Consider the chattering 52A auxiliary contact from Fig. 4. This failure could be caused by a failure in the recloser, its cable, or the recloser control. A digital multimeter can be used to determine whether the 52A auxiliary contact circuit provides a steady signal to the recloser control. If it is determined that the chatter is present at the pins coming into the recloser control cabinet, the digital multimeter can be used to check for continuity and shorts in the recloser control cable. Alternatively, the failed device or part can be identified by replacing one component at a time. For instance, a spare cable can be used to replace the old cable, or a spare recloser control can be loaded with settings from the old recloser control and installed in its place. Once the failed component is identified, only it needs further troubleshooting.

VI. CONCLUSION

Modern microprocessor-based recloser controls offer distribution protection engineers tremendous flexibility, not only with setting a protection scheme but also with fault investigations after a scheme has been commissioned. Recloser controls with SOE record and event record capabilities support a methodical troubleshooting approach when fault investigations are required for in-service installations.

Reclosers with single-pole tripping capabilities allow for flexible scheme installations. However, they also introduce new complexities that must be considered in scheme design and in commissioning. This paper explores these considerations from protection, operations, and safety perspectives.

The recloser control automatic reclosing function is almost as important as its tripping function. This paper discusses the typical reclosing practices and architectures and analyzes desired and undesired reclosing operation examples.

Time-current coordination is somewhat simple to achieve using coordination software tools. However, the dynamic nature of the power system presents scenarios, such as evolving, intermittent, and multiple faults, that can cause misoperations that appear to be because of miscoordination. This paper analyzes the protection system responses to such faults.

A practical and informative commissioning procedure is recommended for a successful recloser scheme installation. A well-organized maintenance program is key to ensure proper operation over the lifespan of a recloser. This paper identifies key points to help field personnel identify the early signs of wear and tear. These signs can also help fine-tune existing maintenance schedules to ensure a healthy and reliable distribution recloser installation.

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VIII. BIOGRAPHIES

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Jeremy Blair, P.E., joined Schweitzer Engineering Laboratories, Inc. as an application engineer in 2013. Previously he worked for Entergy Corporation as a distribution planning engineer with responsibilities in distribution system planning, protection, power quality, and automation in Baton Rouge, Louisiana. He also managed Entergy's Automatic Load Transfer and Sectionalization Program over its four-state territory. Jeremy earned his B.S.E.E. from Louisiana Tech University and his M.S.E.C.E. from Georgia Institute of Technology. He is a licensed professional engineer in the state of Louisiana.