A Case Study: PacifiCorp's Best Practices for Locating High-Impedance Faults

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***Abstract*—High-impedance faults are challenging to detect and locate due to their low fault current and intermittent nature. High-impedance faults are rarely easy for field crews to locate, unless there are obvious physical indicators—such as tree branches on power lines, downed conductors, or broken wires. Most of the high-impedance faults detected are not permanent faults. Most are nearly invisible to the crews sent out to investigate them because they are the result of broken wire leads from taps, damaged conductors, or conductor splices. When a relay detects a high-impedance fault or triggers an alarm, field crews typically patrol the affected line to locate the fault. If no visible signs of a high-impedance fault are found during the patrol, the event is usually classified as either false or indeterminate. After multiple such occurrences, utilities may start to lose confidence in the alarm and fault indications. Recognizing that it is rare to find a downed or a broken conductor, and adjusting the procedures used to investigate high-impedance faults can be valuable.**

Field crews and their management must understand that different expectations will apply when they are sent into the field to investigate potential high-impedance faults. Simply walking the line to detect high-impedance faults makes it unlikely to locate a high percentage of these faults. This paper will provide PacifiCorp's efforts and experimentation to identify and locate high-impedance faults.

I. Introduction

High-impedance faults (HIFs) are ground faults characterized by high resistance in the fault path. The specific resistance value that qualifies as high impedance varies depending on context and interpretation. For this paper, HIFs refer to ground faults that result in low fault current levels below the pickup threshold of conventional ground overcurrent protection. For decades, the power engineering industry has grappled with the challenges of detecting HIFs [1]. Numerous methods have been introduced to address this issue from a detection standpoint, and steady progress has been achieved [2]. However, much of this advancement has focused on developing algorithms implemented in digital protective devices. Despite these innovations, interpreting data from these devices remains a significant hurdle. There are many tools, electric utilities employ to detect HIFs, following are some of the popular ones.

A. Sensitive Earth Fault (SEF)

SEF protection is employed to detect ground faults by monitoring residual currents, particularly when the maximum standing ground current can be accurately estimated [3].

B. Instantaneous Ground Overcurrent (50G) Counting

The 50G counting method counts the number of times a 50G element asserts and deasserts at a very low pickup threshold within a settable period. This activity could indicate the presence of a small magnitude arcing fault on the system [4].

C. Harmonics-Based Detection

This is the most widely used method in relays and recloser controls. Most of the methods are based on using odd harmonics because arcing is more likely to generate odd harmonics and interharmonics. Some relays have threshold-based detection, such as triggering when the third harmonic exceeds a set value or when the ratio of the third harmonic to the fundamental frequency surpasses a defined threshold. Some relays have adaptive thresholds that adapt to the load condition.

Field crews tasked with line inspection are trained to recognize signs of traditional overcurrent faults. When they happen to walk the faulted line, there is a high probability they will successfully identify the issue. However, when digital protective devices indicate the presence of HIFs, traditional line-walking procedures are far less effective. These faults are often subtle and difficult to detect visually. They may manifest as splices incorrectly installed that cause arcing, such as vegetation that intermittently brushes against a line, primary equipment that needs inspection, or loose connections.

The industry is increasingly recognizing that locating HIFs requires a distinct approach compared to traditional overcurrent faults. This process demands more time, resources, and specialized techniques, yet success rates remain low. In many cases, relying solely on visual inspection line patrols will not support HIF detection.

PacifiCorp has developed enhanced procedures for locating HIFs, which they have employed in the case studies discussed in this paper.

The remainder of this paper is organized as follows: Section II describes the need for an organized approach to detect HIFs. Section III describes the preparation needed for applying HIF detection elements in the protective relays. Section IV discusses the approach for balancing security and dependability. Section V describes necessary steps for rolling out a new process for locating HIFs. Section VI discusses the importance of forming and developing a location team. Section VII describes the steps to take after an HIF is triggered. Section VIII lists the HIFs detected by field crews in the last two years. Section IX describes a variety of HIFs successfully located by field crews. Finally, Section X describes the lessons learned in the past four years of detection and locating HIFs.

II. The Benefit of HIF Detection Efforts in Modern Distribution Systems

Modern digital relays with their various operating quantity elements and logic offer engineers the ability to develop complex logic to match specific operational needs. People often underestimate the complexity of designing a distribution protection scheme to meet the challenges facing protection engineers. Distribution protective schemes should be designed with an understanding of the specific environmental requirements of an area. Also, historical construction and operational practices need to be considered in protection scheme design.

Distribution protection systems need to simultaneously address challenges such as branch topology, tapped loads, and considerable unbalance. These challenges create the need for a combination of various protective elements to sense a variety of faults. Therefore, an organized approach to fault detection is needed. Table I shows the types of distribution faults and typical protection elements used to detect them.

TABLE I
TYPICAL PROTECTION ELEMENTS FOR DISTRIBUTION FAULTS

Type of Faults	**Protection Elements Used to Detect Faults**
Three-phase	Instantaneous phase overcurrent (50P), inverse phase time overcurrent (51P)
Phase-phase	50P, 51P, instantaneous negative sequence overcurrent (50Q), inverse-time negative sequence overcurrent (51Q)
Single-phase-to-ground	50P, 51P, 50G, inverse ground time overcurrent (51G)
Two-phase high-impedance arcing	SEF, HIF detection elements
Single-phase-to-ground arcing	HIF detection elements, 50G counting

HIF detection has always been a goal of protection engineers. The introduction of electronic and digital relays has offered a significant opportunity to explore the balance between dependability and security of HIF elements. Recent developments in protective elements used to detect HIFs have increased detection of HIFs. Accordingly, adapting operational procedures to better locate HIFs support the effective implementation of those protective elements.

III. Preparing to Use HIF Elements

Performance evaluation and interpretation of HIF detection algorithm events require active user engagement. Unlike conventional protection elements, such as 50P, 51P, or 50G, HIF detection cannot simply be enabled and expected to operate reliably without user oversight and validation. One such action is to enable the element on a circuit, but only for monitoring purposes. As data are received and analyzed on the circuit, the user can start to build the story for that particular circuit. All circuits are slightly different and require their own individual treatment. As circuit behavior is characterized over time, deviations from normal operations, such as load patterns resembling HIF activity or switching transients, become more apparent to engineers analyzing the data. For this reason, before enabling high-impedance fault detection, set the element to monitoring mode and analyze the HIF event data. Permit breaker tripping only after verifying that all abnormal conditions have been mitigated. If HIF events are found during the monitoring mode, the sources will be investigated and fixed before tripping is enabled on that circuit. Adequate preparation work before enabling tripping via HIF detection methods has helped the utility understand normal circuit behavior versus conditions that require field personnel to investigate.

It is also important to understand the requirements of the detection algorithm and ensure it is aligned with the circuit that is going to be monitored. There should be enough load current to allow the relay to detect the small currents associated with HIFs. Current transformer ratios may need to be adjusted to meet sensitivity requirements of the algorithm in use.

IV. Balancing Between Security and Dependability

It is critical to balance the security and dependability of HIF alarms and fault indications. If the choice is made to heavily lean towards dependability, then every device monitoring HIFs can issue hundreds of alarms that need to be investigated. Some current disturbances in the power system can potentially trigger a HIF alarm depending on the sensitivity of the algorithm. It is generally infeasible to investigate multiple alarms a week. This results in too many alarms for the utility to take action, thus the HIF alarms are ignored. However, if you choose maximum security only a small percentage of HIFs are detected, and thus dependability is sacrificed.

The approach to attaining the balance can be done in multiple ways such as:

A. Heavily Lean One Direction

When approaching HIF detection, it is best to begin with maximum security settings and learn from the events that follow. With maximum security enabled, any HIF that is triggered is likely to be a real HIF. As more knowledge is gained about confirmed HIFs, the sensitivity level of the detection algorithm can be increased to attain balance between maximizing HIF detection and triggering alarms whose sources are not identified by field crews.

B. Event-Based Security

This approach is based on the utility engineers and field personnel's experience with HIFs observed on the system. One strategy includes turning HIF on when an overcurrent disturbance occurs and at the time of reclosing, especially in areas with a higher probability of lines falling on the ground. A broken conductor may contact another phase or neutral, and momentarily create an overcurrent disturbance. If HIF detection is enabled to sensitive mode during an overcurrent trip and reclosing cycle, it can help successfully detect the fault. After a period, the HIF detection can either be turned off or be set to a less sensitive mode. Additionally, HIF detection can be applied after reclosing because a line on the ground while reclosing triggers a HIF alarm right away.

Arcing caused by events such as insulator flashovers or brief vegetation contact can trigger HIF alarms that crews are unable to verify because the condition clears before patrol. To mitigate this, increase the HIF detection pickup time to filter transient HIF events while maintaining sensitivity to sustained faults.

V. Training and Deployment of New Protection Strategies

The success of any program is dependent on all involved parties understanding the expected results of the program. Implementing an HIFs detection program is no different. The following list identifies the stakeholders of the program and their roles.

- Engineers who set the relay and may interpret the results need to understand how the detection algorithm works and how to analyze event data.
- Upper management needs to understand the impact the element will have on outage time and patrol time.
- Front-line management needs to understand the changes to line patrol practices and staffing requirements.
- Corporate communications needs to understand how to communicate the impact of HIFs to customers and the general public.
- Field personnel need to understand how to patrol for HIF events: what to look for and the expected level of detail of the patrol. Patrol teams must be trained to look for subtle signs, as most HIFs are not obvious.
- Relay technicians need information on the proper commissioning of the high-impedance detection algorithm. They also need proper operation training so they can ensure the protective element acts as expected.

The terminology of the above roles is likely to vary from company to company. However, a key takeaway from this section is that the success of a HIFs detection program is dependent on an entire company's understanding of what to expect when transitioning to a new HIF detection program. If a single group is not included in the process, it is likely to cause misunderstanding and prevent the program from meeting its desired outcome.

VI. The Location Team

The success of field personnel responsible for locating HIFs depends heavily on support from both management and engineering. Support can be specific, for example, approving resources such as specialized tools like high-quality binoculars, which can make the difference between identifying the cause of a HIF and missing it entirely. Support also occurs at the programmatic level. For example, sharing successes with stakeholders reinforces the program's value and motivates continued engagement.

Several key factors influence the effectiveness of HIF patrols.

A. Phasing

A primary method of limiting the patrol scope is using phase information. HIFs typically affect a single phase. If phases are mapped and labeled correctly, patrol teams can eliminate unaffected branches and focus only on sections containing the faulted phase. Equipping and training crews with phasing tools ensures accurate patrol targeting. Wireless phase trackers can also verify phasing when mapping is uncertain.

B. Locating Important Information

Patrol personnel, engineers, system operators, and management must understand where useful data resides, how frequently it is updated, and who is responsible for providing it. Examples include:

- Remote engineering access to substation relays and field reclosers for near real-time oscillography
- Alarms generated by advanced metering infrastructure (AMI)
- Complaints related to power quality
- Presence of seasonal or large nonlinear loads on affected feeders

Analyzing these data sources and sharing insights with field crews improves efficiency.

C. Time to Locate

HIF indicators, such as visual arcing, smells, sounds, or abnormal power quality readings, diminish over time. Prompt investigation increases the likelihood of identifying the source. Post-restoration patrol personnel can leverage radio frequency (RF) detection equipment to locate active arcing.

D. Building a Profile Over Time

Some HIF causes are not identified during initial patrols. Continual data gathering (e.g., time of day, AMI alarms, and power quality anomalies) and leveraging local field knowledge help narrow down the fault profile. Repeated patrols and historical pattern analysis improve success rates. Sharing these profiles across operational territories accelerates future investigations.

VII. What to Do After an HIF Fault Is Triggered

HIFs present unique challenges in detection and root cause identification. While some causes, such as a tree contacting a conductor, are relatively easy to identify, most HIF events require significant time and coordination across multiple teams to identify. Unlike typical overcurrent faults, locating HIF sources can take days rather than hours and success depends on realistic expectations, proper training, and collaboration between patrol crews, engineering, and management.

The investigation workflow includes the following steps:

1. Relay data analysis
    - Relay event records should be collected immediately after the alarm.
    - Analyze oscillography to identify fault characteristics.
    - Determine whether the event was load related or indicative of arcing.

- Identify impacted phase(s) and the approximate line section.

2. Subject matter experts (SMEs): involve protection and system operations experts early for interpretation and guidance.
3. Planning and coordination: communicate realistic timelines to management; HIF patrols are inherently slower and more detailed.
   - Provide patrol teams with:
     – Circuit maps highlighting only impacted phases.
     – Service and customer load information to narrow the search area.
   - Ensure management understands the resource and time requirements to avoid misaligned expectations.
4. Field patrol execution
   - Move beyond typical drive-by or lockout patrol methods.
   - Perform detailed inspections: slow down and look for small, subtle signs of arcing or damage.
   - Assign additional patrol resources, if possible, but note that more personnel do not always equate to faster fault location.
5. Recommended tools
   - High-quality optics (binoculars, scopes): for visual inspection of conductors and insulators.
   - RF meters: to detect radio frequency emissions from arcing.
   - Wireless phasing set: for verifying phase relationships without direct contact.
   - SensorLink Troubleman Kit: a portable diagnostic toolset designed for live-line measurements, including voltage, current, and phase angle, enabling crews to quickly assess line conditions and confirm suspected fault areas.
   - Circuit mapping tools: to visualize affected phases and sections.
   - Drones: for aerial inspection of inaccessible areas.

VIII. Examples of Detected HIFs

The cause of HIFs can be difficult to pinpoint following a fault or alarm indication from a digital protective device. Often, distribution lines show no visual signs of a fault because the arcing is intermittent or, at the time of the patrol, the line is no longer in contact with the current path that was causing arcing. Other things to consider when inspecting the line for HIF causes are varying wind direction and speed, time of day, load on the circuit, and weather conditions. In some instances, the fault may lie beyond the utility-owned line and, therefore, be outside the patrol area. The following is a list of various causes of HIFs found during the utility's line patrols:

- Downed primary and secondary conductors.
- Animals and birds.
- Secondary service wires with failed insulation allowing arcing to the neutral conductor.
- Detached primary jumpers that partially welded themselves back to another portion of the jumper or cutout door.
- Intermittent contact with vegetation.
- Failing equipment such as arrestors, cutouts, and insulators.
- Leakage current from conductive equipment mounting arms to the pole.
- Loose secondary connections such as meter base bypass nuts.

IX. Success Stories

The following are some of the HIFs located successfully as the utility continues learning and implementing steps to make HIF detection and location successful.

A. Event 1 (Loose Jumper)

This event occurred on a three-phase lateral around 3.5 miles from the substation. Fig. 1 is a simple one-line diagram that shows the location of the HIF. The utility began receiving alarms from the digital fault recorder (DFR) and substation relay. Initial field patrols along the feeder revealed no issues. Three days later, the substation relay triggered HIF alarms again. Despite multiple patrols, no fault was identified, leading engineers to suspect arcing from the tap changer on the voltage regulator, shown in Fig. 1, located 4.3 miles from the substation on a three-phase lateral.

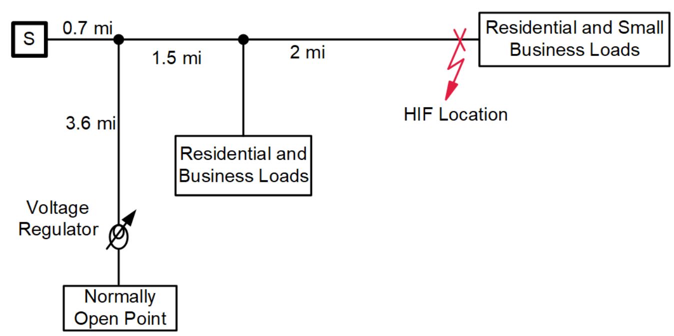


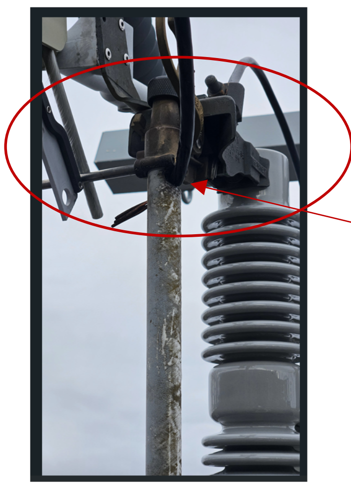
Fig. 1 One-line diagram shows the location of the loose jumper

Due to the intermittent nature of the fault, a dedicated team was assembled to investigate the voltage regulator. The substation relay was closely monitored for signs of arcing activity, and the team manually cycled through the regulator's tap positions to provoke any fault indications. Despite testing all available tap changes, no arcing events were reported by the substation relay, suggesting that the fault may not be directly associated with the regulator's tap operations.

The DFR data indicated a load loss of approximately 30 kVA coinciding with the arcing activity. The team identified potential locations where loads matched this value. Before conducting another field patrol, they reviewed AMI data for concurrent alarms. Several power loss alarms were noted on one phase at 4.2 miles from the substation, where the transformer rating was 30 kVA per phase.

Equipped with these data, the team conducted a follow-up patrol of the line and found arcing from the jumper wire connecting the overhead conductor to the fuse. Fig. 2a illustrates a standard configuration, showing where the jumper wire is normally connected to the fuse mount. Fig. 2b depicts the actual field condition, where the jumper wire became loose, overheated, and ultimately melted, welding itself to the fuse mount. The arcing had likely persisted for several days before the wire welded to the fuse.

(a)



(b)

Fig. 2 (a) standard position of the jumper wire; (b) jumper wire welded itself to the fuse mount

This story highlights the collaboration between teams, the persistence to investigate alarms, and the cross correlation of data from multiple sources that led to the utility detecting the cause and location of HIFs in their system.

B. Event 2 (Snowstorm and Tree Fall)

As previously discussed in Section III, the HIF trip is activated after every circuit goes through an evaluation phase, where the HIF alarms are monitored but not connected to the trip circuit.

This event occurred while HIF detection was in the monitoring stage, which implies that the control was not tripping on the HIF. The simple one-line diagram in Fig. 3 shows a substation and a 12.5 kV feeder extending from the substation. Event 2 began during a snowstorm, when a large tree fell over onto a distribution line. This triggered multiple reclosing shots before successfully closing and resetting the reclosing cycle.

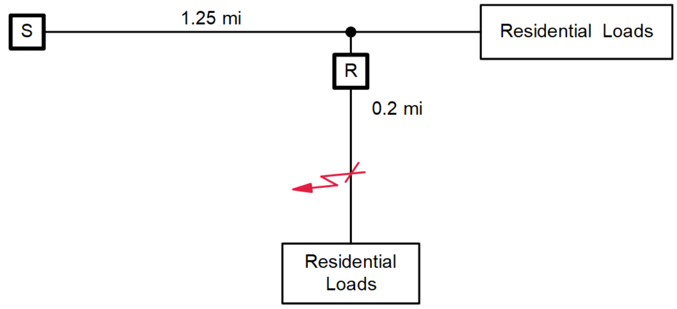


Fig. 3 Location of the fallen tree

Table I shows sequence of events observed on the recloser control (marked with an R in Fig. 3). At T=0 the recloser control locked out after multiple reclosures. An HIF with a downed conductor is detected eight minutes before the lockout. Fig. 4, was captured using Google Maps before (Fig. 4a) and after the event (Fig. 4b). The green circle indicates the missing tree in the after photo.

(a)

(b)

Fig. 4 (a) Before tree fall; (b) after the tree fall. Imagery ®2025 Airbus, Maxar technologies. Map data ®2025 Google

This event is an example of how a secure trip can be carried out. Table II shows multiple HIFs that were detected 10–12 hours before the lockout. One idea is to permit a highly secure trip only when HIFs are associated with a downed conductor. A HIF lockout would have powered off the line eight minutes before the overcurrent element lockout.

TABLE II
SEQUENCE OF EVENTS

Time	Fault Type
0	BG T
–15 s	BG T
–17 s	BG T
–8 min	HIF Fault A, B, C with downed conductor
–9 min 57 s	TRIP
–9 min 58 s	CAG T
–10 hrs 5 min	HIF Fault B
–11 hrs 10 min	HIF Fault B
–11 hrs 22 min	HIF Fault B
–11 hrs 50 min	HIF Fault B
–12 hrs 11 min	HIF Fault B
–12 hrs 58 min	HIF Fault B

C. Event 3 (Service Wire Break)

In this event, an HIF event was detected and the control locked out. After patrolling revealed no signs of an HIF, the operator closed the circuit. Subsequently, a customer called the utility to report that they could hear loud arcing. In response, the field crew manually de-energized the secondary circuit. Upon inspection, the crew discovered that the fault originated from a broken service wire that had fallen to the ground, as illustrated in Fig. 5. The open end of the service wire shown on the top of the figure is the incoming service wire to the customer meter. The scope of patrolling then became larger because the HIF could be on the secondary line of the service transformer as well.

Fig. 5 Service wire break

D. Event 4 (Dump Truck on the Road)

In this incident, a dump truck was traveling along the road with its bed unintentionally raised. The driver was unaware of the raised position and proceeded to drive beneath a 12.5 kV overhead line that ran across the street, as shown in Fig. 6. The substation relay triggered an HIF. However, an HIF trip was not enabled on the feeder as it was in the monitoring phase of the deployment. When the power lines came down, there was no permanent fault, but visible arcing was observed. Emergency services were called, and the utility manually shut down the power.

Fig. 6 Dump truck on the road. Photo: Brian Schnee

E. Event 5 (Service Wire Insulation Leak)

This event highlights a success story of a circuit that locked out on an HIF. This circuit had completed its characterization phase, so tripping was enabled. The device detected an HIF, tripped and locked out. The AMI data from the circuit led the patrol team to a specific area that had a three-phase overhead transformer bank feeding a vineyard with a three-phase pump load. It was recommended to closely inspect the bank pole that served the customer load. Upon closer inspection, it was found that a secondary service conductor's insulation leak was causing the HIF. Fig. 7a shows a secondary tap of a phase wire from the 12.5 kV/480 V service transformer to a business customer. Upon close inspection, one of the phase conductors revealed an insulation leak, as shown in Fig. 7b. Patrol crews found arcing between the phase and the neutral conductor.

This success story highlights the importance of characterizing a line to understand expected behavior before enabling tripping, and having engineers evaluate HIF data after an operation to identify abnormalities. It also highlights the value of cross-correlating AMI data with relay data to communicate potential fault location to line patrol—who carefully investigate to find the cause of the HIFs.

(a)

(b)

Fig. 7 (a) Service point outside the vineyard; (b) insulation leak found

X. Lessons Learned

A. Ruling Out HIF Alarms

HIFs are random events that occur in the power system and should be represented as such in event reports. Any repetitive waveform requires additional analysis before dispatching a crew to locate the fault. For example, waveforms that appear to have a regular repeating shape. This includes repeating magnitudes, on and off durations, and the point on wave that voltage and current waveforms show abnormalities in frequency. Variable frequency drives, for instance, often generate pulse patterns that use power near the voltage peaks of the fundamental frequency voltage sinusoidal waves. These loads sometimes lead to false positive HIF alarms and trips but can be quickly ruled out as nonHIF by analyzing the waveforms.

Additionally, events that happen at regular time intervals, time of day, or seasonally should be analyzed. An example is power electronic driven irrigation load that is not present during winter or shoulder months. The engineer can work with district field personnel to determine when irrigation begins and closely monitor relaying devices for HIF activity. If the activity appears at similar times of day as the irrigation load operators run their equipment, it is possibly not an actual HIF being detected but instead nonlinear load distorting voltage and current waveforms.

B. Leverage Other Data Sources

As the utility evolves their HIF detection program, additional information has been beneficial when attempting to locate HIFs. Once an HIF is confirmed, the location of the fault can be on any part of the identified feeder, leads to large patrol areas with limited ability to help narrow down the scope for field patrol teams. Therefore, leveraging new and alternative data sources is the primary method to narrow the scope and lead to a faster and more accurate HIF location.

One such source is AMI system. AMI system can send real-time or near real-time alarms to the distribution management system. Configuring AMI system to capture certain types of alarms that have been found to correlate to HIF activity that originates on the secondary or customer side of the meter can reduce patrol scope from dozens of line miles to single service transformer locations. A couple of examples of types of alarms that have been successfully used to locate HIF causes are high neutral current alarms indicating that one hot leg has higher impedance and frequent power on or off indicating series arcing.

Customer power quality complaints also provide valuable insight. Customers that notice power quality issues can highlight areas of interest for more detailed inspection and patrol. Flickering, voltage sags not related to other known overcurrent faults, and outages can indicate service points that have failing connections or other equipment in the process of failure.

RF patrol and inspection is another effective method. HIF arcing events produce RF waves that can be identified and located using RF detecting equipment. Equipping and training patrol teams to use these tools during HIF location patrol can locate HIFs that visual patrols are unable to locate.

Drone patrols offer a unique advantage in identifying HIF-related issues that can be difficult to see from the ground. A leaking aluminum-backed insulator connected to the pole top might show obvious tracking in the air that is impossible to see from the ground. Another advantage of the drone patrol is getting a fresh set of eyes and different points of view, which has helped patrol teams identify new conditions that previously went unseen. Drone patrols also provide additional time to perform more detailed inspections that are required to locate some HIFs.

Finally, customer outage calls can be instrumental. Customers have called during outages reporting arcing sounds and visual evidence that can be used to quickly identify high priority patrol locations.

XI. Conclusions

HIF detection presents unique challenges that conventional overcurrent protection cannot address. Utility engineers must rely on integrated data from relays, fault recorders, controls, and AMI systems to identify these faults effectively. Field crews need ongoing training to recognize fault indicators during patrols. While good progress has been made, continued refinement of detection methods is essential. Successful identification of HIFs depends on collaboration across engineering, operations, and management, and these coordinated efforts are already improving fault location and prevention across the grid.

XII. Acknowledgments

The authors would like to thank the operations professionals that have shared their wisdom to help in the application of the high-impedance detection elements. This includes line personnel, relay technicians, operations management, system operators, and engineers. Their dedication to improving system performance enables the effort.

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XIV. Biographies

Shaun Akers holds a BS in electrical engineering from Oregon State University and has contributed to wildfire mitigation, asset management, and operational analytics since joining PacifiCorp in 2018. He is a senior real-time grid engineer at PacifiCorp, specializing in HIF detection and mitigation in medium-voltage distribution systems. Prior to his engineering career, he spent eight years in switchgear manufacturing.

Chad Ooten began his career in the electric utility industry as a line apprentice in construction in 1991. He advanced to journeyman lineman in 1994 and joined PacifiCorp in 1996 as a journeyman lineman in Wyoming. From 2006 to 2021, Chad served in operations management as area line crew manager in Yakima, Washington. He currently works as a project manager in PacifiCorp's Relay Technical Support Group, where he supports field operations and relay testing.

Paul Harris earned his BS in electrical engineering from Washington State University. With over three decades of experience in power system operations, he has held diverse roles in Standards and Planning Engineering, manager in Distribution Engineering, Line and Substation Operations, and principal engineer in Engineering and Relay Support. Currently Paul serves as managing director of technical services, where he oversees support for relay, apparatus, communications and commissioning operations.

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 engineering manager working in the distribution, controls, and sensors division supporting product applications along with the development of new products.

Ravindra Mulpuri holds a Master of Science in Electrical Engineering (MSEE) from New Mexico State University. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2007 as an associate power engineer. Over the years, he has supported and led the development of various distribution protection and control products. Ravindra is currently a senior engineer in the Distribution, Controls, and Sensors division at SEL, where he focuses on product applications and the development of new products for modern distribution systems.