Improve Reliability and Power Quality on Any System

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***Abstract*—Individual devices, such as recloser controls, voltage regulator controls, capacitor controls, and faulted circuit indicators, have been used for years in point applications, but today, integrated systems connect these devices into a complete system. Advancements in both local and remote communications have afforded methods to use information from completely different devices to automate the grid for improved reliability and efficiency. For example, voltages measured at a regulator out on the network can be used by a distribution automation controller to control a capacitor bank in the substation for optimum feeder efficiency.**

This paper addresses the automation of distribution systems to reconfigure the network in the case of system disturbances and changes in loads. A discussion of control actions to minimize the number of customers impacted by system events is provided. Additional control functions of an advanced system are also discussed.

***Index Terms*—automation, control, distribution, fault location, intelligent network, power quality, protection, reliability, secure communication, and volt/VAR optimization.**

I. Introduction

As utilities continue to make strides in what is now commonly referred to as the "smart grid," consideration should be given to automating processes and coordinating point application devices—such as relays, recloser controls, voltage regulators, capacitor controls, faulted circuit indicators, meters, and communications devices—into one complete system. Keeping a complete system in mind allows utilities to use advanced features in these devices, such as self-diagnostics, harmonic metering, and synchrophasors, to maximize reliability and power quality while improving safety and reducing operating costs. These capabilities are tied into the same communications systems that are used for power system monitoring and control to increase system efficiency by gathering valuable information. Using a system-wide approach allows utilities to implement more advanced, efficient, and cost-effective automation schemes. New intelligent electronic devices (IEDs), along with existing IEDs already in use today, have advanced automation features that, when optimized, maximize system reliability and power quality.

In this paper, we first take a step back to review common measurements of distribution system reliability and power quality, as well as areas in which to improve these measurements; then we discuss modern automation methods that are being adopted to greatly improve reliability and power quality. Although each utility has different priorities, budgets, equipment, and topology, this paper addresses methods that work for any system, starting with little to no automation and building toward a complete and fully automated system.

II. Present Practice Overview

A. Traditional Reliability and Power Quality Measurements

Because reliability is very important to all customers of electrical power, utilities use reliability indices to track power transfer to their customers [1]. Traditional reliability measurements include customers per outage, outage duration, and outage frequency. Reliability indices most commonly used by electric utilities include the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). Table I defines how these indices are calculated. Outage and interruption are two terms that may be defined differently by each utility, but both cost utilities money, give customers reliability concerns, and have significant costs related to interruptions in industrial processes.

TABLE I
TRADITIONAL RELIABILITY INDICES

Index	Calculation
SAIDI	$\dfrac{\Sigma \text{ (Outage Duration)} \bullet \text{(Customers Affected)}}{\text{Total Customers}}$
SAIFI	$\dfrac{\text{Customers Interrupted} \bullet \text{(Number of Interruptions)}}{\text{Total Customers}}$
CAIDI	$\dfrac{\Sigma \text{ Customer Interruption Durations}}{\text{Number of Customer Interruptions}}$

Although there are several standards that describe power quality requirements for utilities, including IEEE 1150-1995 and IEC 61000, the average household is unaware of the quality of power. For many industrial consumers, however, power quality is a growing concern. The addition of new sources on the system, changing load characteristics, and the fact that many systems operate closer to stability limits result in poor power quality, such as voltage sags, harmonics, or transients. These issues may not affect an average home but may lead to expensive equipment shutdown or failure within industrial loads.

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B. Typical Reliability and Power Quality Solutions

There are several approaches to improve reliability and power quality, which fall into two categories: pre-disturbance and post-disturbance. To improve safety, power quality, and reliability, common pre-disturbance methods include protection improvements, voltage and VAR control through power factor correction and voltage optimization, and system analysis and maintenance. Post-disturbance actions taken are fault location methods and event analysis. Although these methods individually help to reduce the frequency and duration of system disturbances [2], they lack system-wide coordination to maximize their potential.

1) Pre-Disturbance Reliability and Power Quality Solutions

Today, utilities strive to mitigate or eliminate system disturbances and maximize system reliability, improve efficiency, and reduce costs. Fault location, isolation, and service restoration (FLISR) schemes are implemented to reduce system disturbances and the number of customers affected by permanent outages. Applying reclosing and/or single-phase tripping further reduces the number of customers impacted. In the past, utilities relied on electromechanical relay protection and coordinated devices with time delays, a method that suffers from inaccuracies within the devices. With the invention of microprocessor-based relays, there have been advancements in protection and coordination, as well as the addition of many tools for automation. As point devices, modern relays increase protection sensitivity and, by using multiple levels of protection, increase the speed of clearing faults to reduce the impact on the system. These capabilities are enhanced with system-wide coordination, as discussed later in this paper.

By understanding load characteristics and voltage profiles, utilities are able to apply volt/VAR control schemes that improve power quality and reduce losses in the system. Power factor is a very important measurement for understanding excessive losses within a system. To increase power factor, switched and fixed capacitor banks are often used to control voltage and mitigate losses on a distribution system. The biggest obstacles in applying switched capacitors may be the instrumentation costs for measuring true power factor. Without an accurate measurement, it is difficult to optimize coordination and gain the most benefit. It is also important to avoid problems with overvoltage and overcompensation, which adds excessive kVARs into the system. Additionally, voltage regulators are used in substations and downline to raise and lower voltage as required. They compensate for voltage losses to maintain voltage requirements at the load. Voltage regulators are also used in voltage reduction schemes; reducing the voltage on resistive loads reduces demand and energy consumption. Although capacitors and voltage regulators provide improvements in efficient voltage delivery, the optimization of voltage and VAR on a distribution feeder is enhanced through coordination of these devices.

Additionally, metering values are gathered throughout the system to help measure power quality and assist in system studies and planning. Harmonic distortion on a distribution system is a growing concern and has adverse effects on power quality and reliability. Understanding load characteristics during peak demand on a system provides an opportunity for appropriate conservation voltage reduction, providing savings to both the utility and the customer. Gathering demand and energy metering data is also needed for system planning to optimize load capacity and assist in planning for future development.

Other important actions utilities must take to improve reliability and power quality are necessary maintenance and testing. Blown fuses on capacitor banks, damaged conductors, and breaker wear all have significant negative impacts to reliability and power quality.

2) Post-Disturbance Reliability and Power Quality Solutions

Reducing the time to locate and clear faults has the greatest positive impact on reliability indices. Effectively locating faults is very difficult on a distribution system. Relying either on customers to call and report an outage or on crews to patrol the line to locate faults is inefficient and time-consuming but is the common approach today. Although many IEDs provide a calculated distance to a fault, most IEDs use impedance-based calculation methods that are commonly used for transmission fault location but are inaccurate on distribution systems because of their complex feeder configurations. Statistical analysis has been used for determining locations based on fault current levels. Many utilities are starting to use system models and software packages for location estimations. Using faulted circuit indicators greatly improves these methods, but without an automated solution, statistical analysis and system models are only as fast as the data collection methods supporting them.

Sequential Events Recorder (SER) reports also help utility engineers and technicians understand system disturbances and equipment behavior. Oscillographic event reports provide time-stamped measurements of faults. Both SER reports and oscillography provide a means for understanding, measuring, and improving reliability and power quality. One of the biggest hurdles faced with event analysis is data collection and aggregation. Software solutions are now available to automate this task and are powerful tools for post-disturbance analysis.

III. Distribution Network Automation

A. Communications

The need to collect and store data from IEDs for further analysis [3] has driven advancements in communications systems and protocols. The adoption of IEDs in the last 25-plus years has led to the recognition of the benefits of automation systems based on the communications capabilities of these devices. Taking information out of IEDs and sharing it with other devices on the system greatly improve protection speeds and simplicity [4]. Communication with IEDs was originally necessary only for setting and configuring protection devices. Now, utilities collect data from IEDs for advanced automation applications.

IEDs measure system quantities, such as voltages, currents, and breaker status, and make decisions based on these measurements according to protection or control settings and configurations. IEDs also record useful information for fault location and event analysis during system disturbances. Collecting this information, along with additional monitoring reports, such as load profile reports, voltage sag, swell, and interruption recordings, and breaker wear reports, can be a burdensome task without an automated system, especially as more information becomes available.

Advanced fault location methods benefit from rapid data collection to provide very accurate fault location [5], saving valuable time and effort. Because distribution circuits today are not homogeneous and have multiple laterals and sublaterals, it is difficult to locate faults based on station relaying alone. A better fault location method coordinates information taken from relays and other distributed IEDs to automatically and accurately locate faults, even on complicated distribution systems. This method takes instantaneous current and voltage measurements recorded by digital relays in the substation during fault conditions, as well as those recorded by other devices on the line that have current and voltage recording capability. It also processes information regarding the nonhomogeneous characteristics of the distribution system. Using these measurements and the topology information of the feeder, this method determines the fault type and calculates the total reactance from the device location to the fault location. This method pinpoints the fault location to reduce fault-finding time and cost.

Time synchronization of IEDs with Global Positioning System (GPS) clocks is also providing a path for further advancement in control, automation, and system analysis using synchrophasors. Synchrophasors allow system operators to see a real-time snapshot of the system rather than work from a time-delayed, estimated system state.

Serial communications have been widely used in distribution automation applications. The best method for any given application is dependent on many things, such as budget, system performance, and criticality of the load served. Serial radios have proven to be very cost-effective when used in either point-to-point or point-to-multipoint configurations. These communications links are a low-cost solution for engineering access and event retrieval, as well as protection applications [6]. IEDs provide serial protocols that were developed to allow remote engineering access and event and metering collection across the same serial communications link. Communications processors allow supervisory control and data acquisition-based (SCADA-based) situational awareness and control by using protocols such as DNP3 and Modbus® to collect and concentrate data from numerous devices throughout the system and display the data in simple, meaningful ways. IEDs are able to pass a few pertinent bits to adjacent relays on the circuit at high speeds, with very low bandwidth requirements, for protection and control applications. Faulted circuit indicators now have radio communications to provide system condition information and assist in rapid fault location [7].

Ethernet protocols are making their way into power system automation and control because of their ability to handle multiple protocols with one communications link, a result of their high-bandwidth nature. Ethernet communications provide engineering access, SCADA protocols, web server accessibility, and other services, conveniently tied into a common communications medium. There are currently many options for both wired and wireless Ethernet communications. Ethernet is well suited for automation applications but must be carefully considered for protection applications because of the lack of determinism in the communications channel.

B. Security

Secure communications are becoming increasingly important. IEDs provide multiple levels of password protection within the devices to prevent unauthorized access. Data encryption is also an important part of protecting the critical infrastructure of the power system. Radios may incorporate data encryption, as discussed in [6]. Encrypting data ensures that the data cannot be compromised or manipulated by outside sources and protects critical protection and control actions. Security gateways are also a good choice for the protection of critical assets because they provide a means of managing passwords, tracking remote access activity, and limiting user interaction to authorized tasks. It is important to evaluate the security of devices throughout the system to ensure a robust security solution. Addressing cybersecurity and physical security at multiple levels results in a commonsense, security-in-depth solution.

C. Automation and Control

1) Distributed Control

The coordination of modern protective relays and controls increases the reliability of a system. One example of effective coordination is Automatic Network Reconfiguration (ANR), or FLISR, which includes sectionalizing permanently faulted segments and restoring power to nonfaulted segments so an outage impacts the fewest number of customers. Distributed control techniques for ANR may be accomplished with or without communications. Without communications, ANR schemes operate by monitoring voltage at each switch and depend on time-coordinated switch operations to reconfigure. These schemes can operate in less than a minute to isolate the faulted section of the line and restore load, a significant improvement compared to the time required to manually restore the load [4]. Although these schemes are economical to install because they do not require communications equipment, control decisions are made based only on local measurement, which does not take into account the state of the larger distribution network.

Peer-to-peer communications provide a more deterministic and high-speed approach to clearing faults, thereby improving reliability indices. Peer-to-peer communications eliminate inaccuracies and possible misapplications of coordinating time-overcurrent curves. Fig. 1 shows an example of a simple networked distribution system using communications for clearing faults and restoring power to unaffected zones. No longer having to coordinate with multiple downstream devices decreases the time to clear faults and reduces the overall impact on the system. A relay or recloser control communicates with other devices upstream and/or downstream to determine which devices should trip to minimize the number of impacted customers. The local coordination is simplified to just coordinating with fuses within the given zone. As shown in Fig. 1, the source recloser only needs to coordinate with fuses in Zone B. A permanent fault in Zone B results in the source recloser tripping to lockout, clearing the fault, the midpoint recloser tripping to isolate the fault, and the tie recloser closing to restore power to the unaffected customers in Zone C.

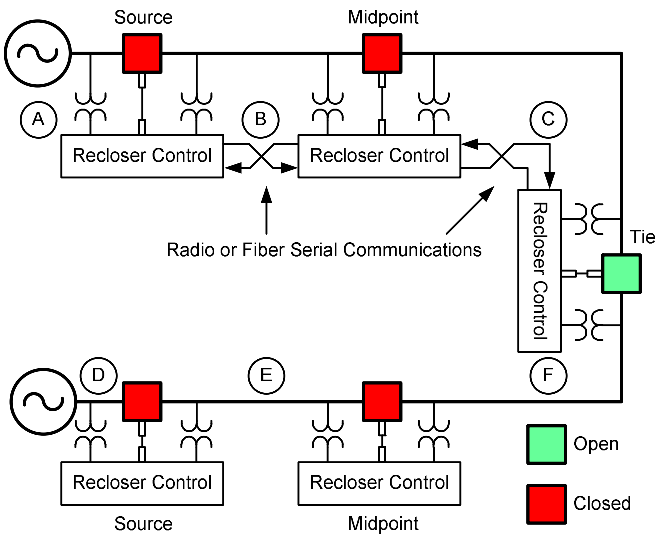

Fig. 1. Distributed control for protection and ANR

2) Centralized Control

A centralized approach to distribution automation provides benefits in many areas of reliability and power quality. A centralized control automatically coordinates point application devices from a central location, such as a substation or control center. As [8] shows, wide-area control through a centralized system provides numerous benefits in improving reliability and power quality.

Point application devices, such as relays, recloser controls, voltage regulators, capacitor controls, faulted circuit indicators, meters, and communications devices, are all monitored and controlled through a centralized control. This provides a means for automating many processes that used to be dependent on operator control or were not possible at all. Event retrieval and advanced fault location, as discussed in [3] and [5], are incorporated into the system to reduce the time, effort, and investment for these activities. Metering, monitoring, and diagnostic data within IEDs are automatically collected to assist in system studies and planning and system maintenance and testing. Volt/VAR control is implemented within the centralized control, greatly simplifying and improving this process. The system may be programmed with system capabilities, which, when combined with complete situational awareness, allow the system to provide fault isolation, load balancing, load shedding, miscoordination detection, and more.

Because of voltage drop due to impedances in the line and reactive power flow, many utilities run their distribution systems with conservatively high voltage to compensate for the voltage drops inherent in the grid. Voltage regulation, either at the load tap changer or voltage regulator, compensates for voltage losses to maintain voltage requirements at the load. Capacitors control VAR flow to maintain unity power factor for efficient power transfer. Voltage regulators, load tap changers, and capacitors, when used as point devices, significantly improve voltage management and power factor, but incorporating these devices into a complete system offers maximum benefit for improved reliability and power quality. Load characterization algorithms in voltage regulator controls allow implementation of more intelligent voltage reduction schemes. With this information, it is possible to increase efficiency during certain loading conditions. Historically, distribution circuits consisted of heavily resistive loads, so a simple voltage reduction decision was straightforward. Today, however, distribution circuits are an intricate mix of constant current, constant impedance, and constant power loads, so voltage reduction is not as readily clear. When loads are primarily constant power, lowering the voltage increases the current, causing more losses on the system. In this case, voltage reduction is not a wise decision. In the case of constant current or constant impedance loads, voltage reduction is an economical choice for the utility, resulting in voltage conservation with lower losses. By looking at load characterization data from voltage regulator controls, utilities determine the types of loads connected to the system and make the right conservation voltage reduction decisions. A centralized distribution automation control automatically operates capacitors to improve power factor and minimize VAR flow along a distribution feeder. It also automatically manages voltage profile by operating voltage regulators to shift voltage up or down. A centralized volt/VAR solution will correct and control power factor at the substation bus and reduce losses along the feeder. This includes maintaining a voltage band on the feeder, minimizing regulator operations, and preventing frequent capacitor operations.

IV. Implementation Examples

The following examples reference an overhead system with reclosers, but the protection and automation principles apply to underground distribution with underground or pad-mounted equipment. At a basic level, a distribution feeder may include just a circuit breaker (CB) or recloser (R) in a substation and not have any downline intelligent devices. This is illustrated in Fig. 2, where a substation device is only required to coordinate with fuses on lateral taps. This is a starting point for many utilities as they begin looking at feeder modernization to improve reliability and power quality. In recent years, many utilities have added intelligent line devices for protection, control, automation, and communication. The following implementation example shows a logical progression, which may be adjusted to fit the present objectives or needs of any utility.

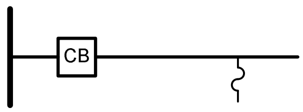

Fig. 2. Basic feeder arrangement with substation protection coordinating with downline fuses

Fig. 3 shows the addition of several reclosers to the feeder. These may be hydraulic or modern reclosers with microprocessor-based controls. In this example, the line protection devices are not communicating and are using time coordination with downline fuses or protection devices.

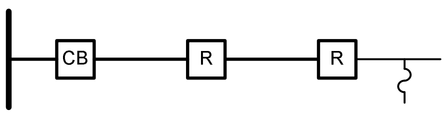

Fig. 3. Feeder with substation protection and line reclosers

Additional protection devices on a single feeder allow for a smaller portion of the feeder to be isolated for downline faults, but simple time-coordinated protection requires progressively longer time delays for upline protection. A fault close to the substation may see a relatively long trip delay to allow for coordination, leading to increased equipment wear. Fig. 4 shows the addition of high-speed peer-to-peer communication between intelligent recloser controls on the feeder. High-speed communication eliminates the need for conventional time coordination between protection devices, other than downstream fuses.

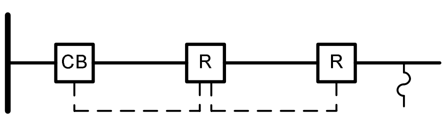

Fig. 4. High-speed peer-to-peer communications improves coordination of protection

Reliability is improved further by adding interconnections between multiple feeders so that any section of feeder may be fed from more than one source, depending on the configuration of reclosers or switches at tie points. Fig. 5 shows a basic looped distribution feeder without communications. Built-in automation logic may be used without communication to automate protection and account for several different feeder configurations. Without communications to each device, the system will need to use time coordination for protection and time delays for automation. The possibility of loop flows in the system normally dictates that one of the devices in the loop is open.

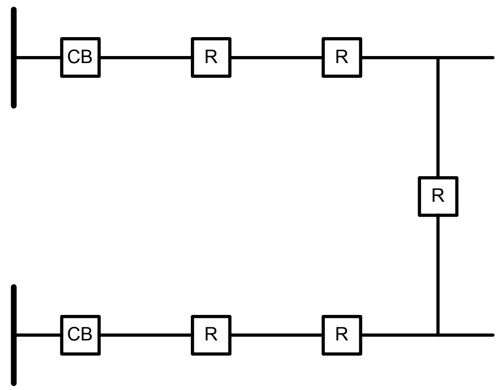

Fig. 5. Basic looped distribution feeder without communications

The addition of high-speed peer-to-peer communications, as shown in Fig. 6, improves not only the coordination of protection between devices but also the automation of switching to reconfigure the system. Automation logic in each line device allows it to make intelligent decisions based on fault detection and the presence of voltage on one or both sides of the recloser.

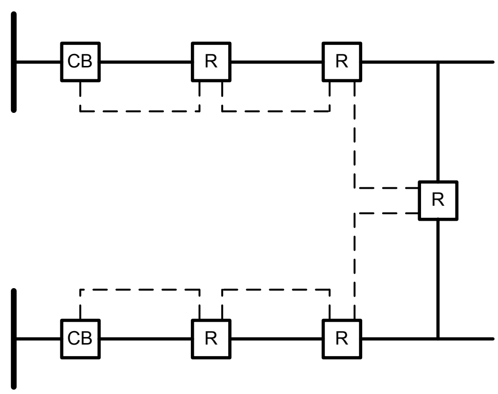

Fig. 6. Basic looped distribution feeder with peer-to-peer communications

A centralized control for feeder automation is useful when coordinating a large or very diverse distribution system. Peer-to-peer systems become more complex as more interconnections or multiple sources are added to the system. Fig. 7 shows a centralized control system used for automation. Protection functions should still be addressed locally in each device or using high-speed peer-to-peer communications. A hybrid system, which uses peer-to-peer communications for protection and a centralized control for automation and advanced features, is shown later.

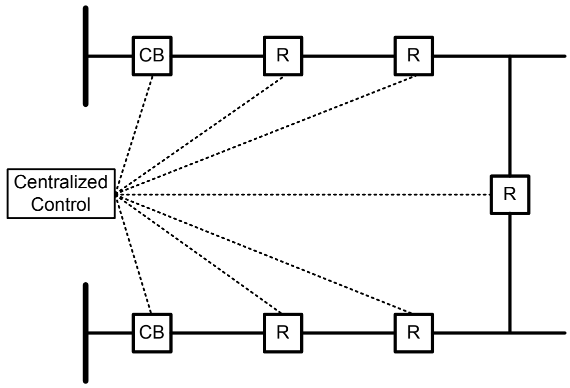

Fig. 7. Looped distribution system with a centralized control for automation

In addition to automating feeder reconfiguration, a centralized control is ideal for optimizing the efficiency of the distribution feeder and improving power quality. Fig. 8 shows the addition of communication to voltage regulator controls and capacitor controls so their operation may be coordinated with the present system configuration and feeder performance be optimized across the system.

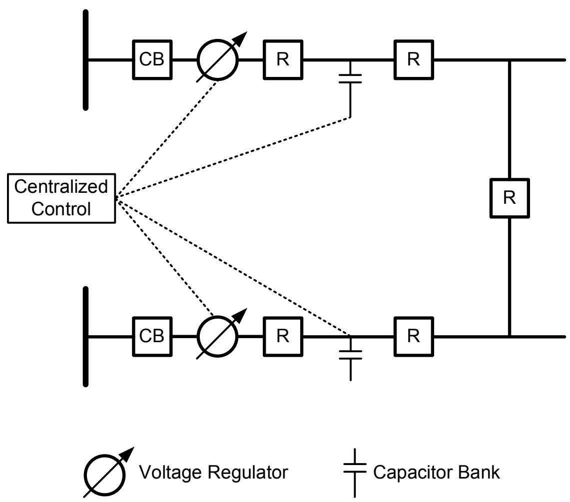

Fig. 8. Distribution feeder with a centralized control for voltage regulator and capacitor control automation

The same centralized control is used for both FLISR and optimized volt/VAR control applications. This simplifies the requirements for communications infrastructure and provides the best coordination between different aspects of feeder optimization. Fig. 9 shows an example system that uses a centralized control for automation functions and high-speed peer-to-peer communications between protection devices. This hybrid approach provides the highest degree of automation and fastest protection coordination.

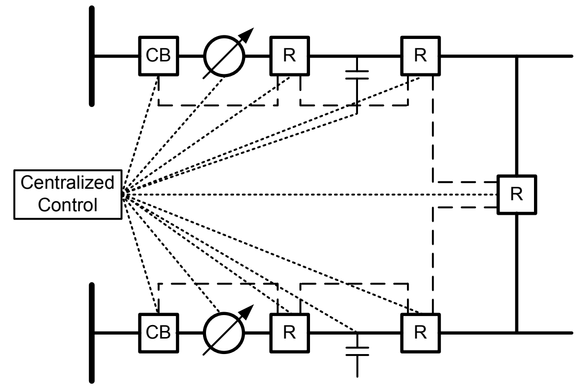

Fig. 9. Advanced distribution configuration with centralized automation control and high-speed peer-to-peer protection

Fig. 10 shows the addition of communicating fault indicators to provide line-monitoring data and finer resolution of fault location. The addition of intelligent line devices, such as fault indicators provides very accurate fault location, especially when using fault location software, which uses data from line devices. Many fault indicators also include a visual display to help line crews locate faults faster.

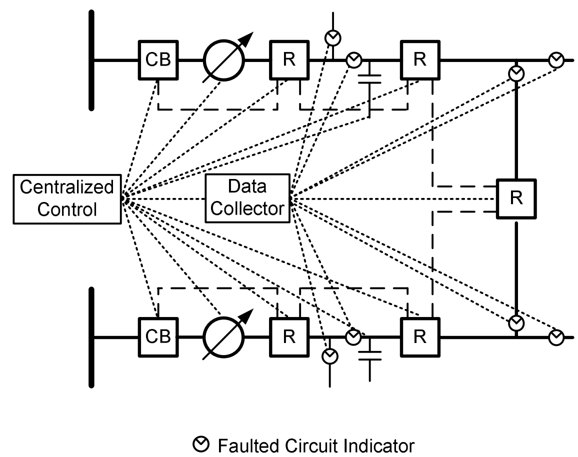

Fig. 10. Advanced distribution automation system with wireless fault indicators

V. Conclusion

Using a system-wide approach and combining local- and wide-area communications provide the highest level of distribution automation. IED capabilities are underutilized in many systems. The use of advanced automation and communications features provides dramatic improvements to distribution system reliability and power quality. Using a system-wide approach to protection, automation, and communications helps maximize the potential of IEDs in service and creates additional opportunities for improvements in reliability and power quality. Any utility will see improvements in reliability and power quality by taking advantage of the automation, control, and communications features built into modern IEDs.

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VII. Biographies

Bill Glennon received his B.S. in electrical engineering from Montana Technical University in 2009. He is a power engineer in the power systems department at Schweitzer Engineering Laboratories, Inc. Bill has over two years of experience in electrical power systems, specifically in distribution controls. He is a registered Engineer in Training.

Christina Kusch received her B.S. in electrical engineering, with honors, from University of California, Los Angeles, in 2000. She is a marketing engineer in the power systems department at Schweitzer Engineering Laboratories, Inc. Christina has over four years of experience in electrical power systems, including substation protection and distribution controls. She is a member of the IEEE and the IEEE Power & Energy Society and is a registered Engineer in Training.

Elijah Nelson received his B.S. in electrical engineering from Washington State University in 2006. He joined Schweitzer Engineering Laboratories, Inc. in 2006 and has held the positions of product manager and marketing engineer responsible for distribution relays and distribution controls worldwide. He currently holds the position of technical marketing manager in research and development. Eli has been a member of the IEEE since 2002.

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