

Distribution Automation Systems With Advanced Features

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Distribution Automation Systems With Advanced Features

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Abstract—This paper examines the use of wide-area distribution automation (DA) systems in electric power distribution systems. The number of DA systems installed on an annual basis is increasing. Many of these projects encompass a large area of a distribution system. Wide-area DA holds the promise of further increasing distribution system reliability. This paper presents wide-area DA strategies and discusses the potential impact on system operation.

The paper also looks at the effects of communications outages on the performance of DA systems. Backup solutions are discussed that allow the DA system to function when a communications link fails. Topics covered in this paper include:

- An overview of wide-area DA. This overview presents the objectives and basic operating principles of automatic circuit reconfiguration in recovering from electrical faults. Advanced features, such as splitting feeder loads between multiple sources when a feeder is reconfigured and transferring load off of a feeder that was previously reconfigured if an overload develops, are also covered.
- The use of multiple distribution automation controllers (DACs) for automating large areas of a power system.
- The impact on system operation practices. This portion of the paper discusses how the operation of the distribution system is affected by the presence of wide-area DA systems.
- The use of backup logic to allow reconfiguration of the distribution system after an outage when a communications link is down.

I. INTRODUCTION

Wide-area automatic control systems increase the reliability of distribution systems but also introduce some challenges. This paper discusses features of these systems, their benefits, and challenges in implementing them.

Utility engineers have developed automatic control strategies and applied them on distribution systems for many years. In recent years, utilities have deployed more sophisticated automatic control strategies that act with a larger scope of responsibility. This has been driven, in part, by the increasing availability of economical communications technologies. Automatic network reconfiguration controllers respond quickly to permanent fault conditions and restore

power to de-energized loads. Some of these systems can be easily applied to complex feeder arrangements that are not suitable for simple loop schemes. These control systems can transfer loads automatically to balance load between feeders after an outage.

As distribution systems become more complex, the opportunities to increase reliability multiply. A utility can take advantage of multiple alternate sources to increase reliability. However, it is not practical to require human dispatchers to perform all the necessary checks and analyze loading conditions before transferring load to an alternate source. There may be several possible courses of action for a given event. Each course of action may require several operations to be performed in a specific sequence (e.g., switching, tap changes, capacitor banks, and protection optimization). Additionally, system and safety checks must be performed to ensure equipment ratings are not exceeded and personnel safety is not compromised. Wide-area control systems automate these tasks to allow utilities to take advantage of the opportunity for increased reliability in complex distribution networks. However, the designers and users of these sophisticated systems must exercise diligence to avoid potential pitfalls in their applications.

Wide-area control systems may degrade the effectiveness of traditional protection practices. After the wide-area control system operates, the distribution network will no longer be in the normal configuration. Protection devices that were coordinated may no longer be coordinated in the new network arrangement. It is important for the controller to be able to change settings groups in the end devices so that coordination is maintained.

Distribution system operation involves interactions with human operators in the control center and in the field. Wide-area automatic controls will take some control decisions away from the dispatcher and introduce new situations that require dispatcher involvement. Design details of the wide-area control system also have effects on power system operations. The effects on the distribution system must be understood to ensure that the safe and effective operation of the distribution system is not compromised.

II. WIDE-AREA CONTROL OVERVIEW

A. Control Objectives

Wide-area automatic control is a broad concept that encompasses many system-wide control objectives in the distribution system, including the following:

- Service restoration
- Miscoordination detection
- Loss reduction
- Dynamic load balancing and load shedding
- Data sharing with adjacent control areas
- Communications link failure detection
- Enhanced situational awareness

These objectives are interdependent. For example, restoring service to a feeder section may result in overload conditions, excessive voltage drop, or power factor degradation. The control system may need to transfer load from the overloaded feeder to adjacent feeders or, perhaps, shed noncritical load to alleviate actual or predicted overloads. In cases where there are multiple alternate feeds that could be used to restore service, the control system will select the alternative feeder that has the most capacity.

The control system must be dynamic in determining overload conditions. As an example, an outage may occur during the night when the load is very light. The system reconfigures to isolate the faulted line section and restores load in the area. When morning arrives, the load increases dramatically and overloads a section of the line. The system has to react to these dynamic changes in load and either move load to another source that has extra capacity or shed load to keep from damaging equipment.

Several supporting functions assist in achieving the main control objectives, including the following:

- Metering and control
- Fault locating
- Fault isolation
- Safety checks
- Operating constraint checks
- Topology analysis
- Reliability calculations and logging
- Event recording
- Visualization
- Communications monitoring

The wide-area control system actuates the following typical apparatus found in the distribution network:

- Breakers
- Reclosers
- Motor-operated switches
- Sectionalizers

B. Loop Schemes

Over the years, distribution engineers have designed loop schemes that are very effective for well-defined circuits. These schemes traditionally operate without communication by monitoring voltage at each switch to detect outages and restore loads. Implementations vary but typically apply to two radial feeders separated by a normally open switch. Voltage-based loop schemes rely on time-coordinated switch operations to isolate faulted line sections and restore service to nonfaulted sections. These schemes typically operate, where possible, in less than a minute to isolate the faulted section of the line and restore load [1]. This is a dramatic improvement compared to the time required to restore load manually.

These types of schemes benefit from the robust logic processing capability of modern controls. These schemes are also very economical to install, because they do not require communications equipment for their operation. This allows the use of these types of schemes in rough terrain where installation of a communications system may be cost-prohibitive. The drawback of using a loop scheme is that control decisions rely only on local measurement. Local field devices have very little awareness of the state of the larger distribution network. Circuit capacity or line loading at the time these schemes operate is usually not checked because these factors are usually considered by the distribution engineers when the scheme is planned.

Some loop schemes are engineered to utilize high-speed communications systems to dramatically increase their operating speed and fault isolation capabilities. Optical fiber is typically the medium of choice. Dark optical fibers and optical fibers associated with multiplexers have both been used successfully. The addition of a high-speed communications system provides the opportunity to further decrease the restoration time. Utilities have implemented schemes using protection-oriented communications technology to clear faults and restore load in less than one second [2] and, in some cases, only a few cycles [3]. Each relay passes a few pertinent bits to adjacent relays on the circuit at high speeds. Using communication not only reduces restoration times but also reduces the effects on customers that still have power. The addition of the communications system provides the means to make the scheme intelligent enough to prevent closing into a faulted line section from an alternate source. Loop schemes without communication will test the line and potentially close into a fault, causing a voltage dip for customers who were not affected by the initial fault.

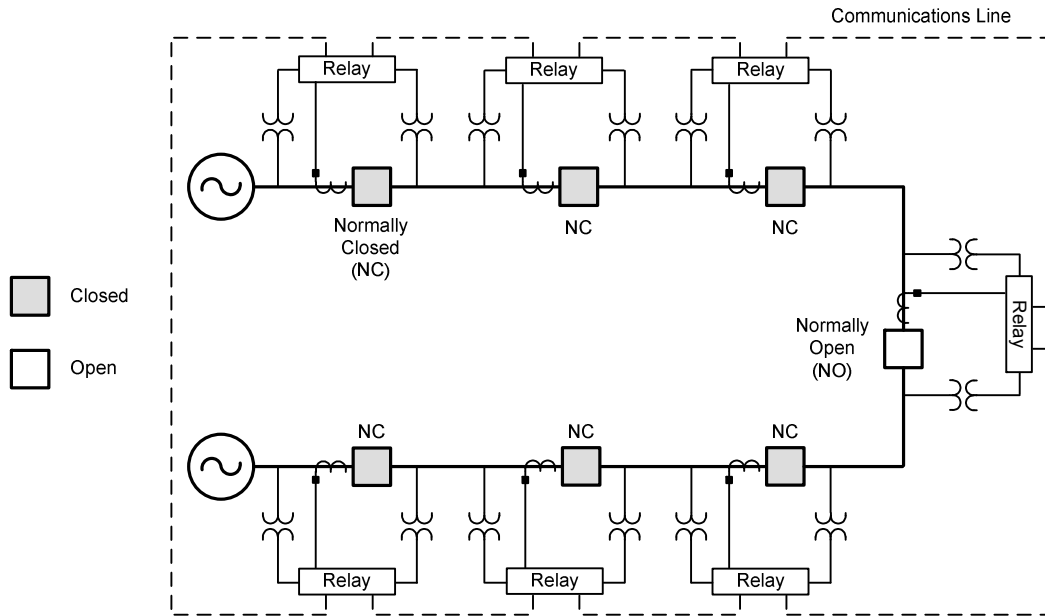


Fig. 1. Simple loop scheme with optional peer-to-peer communication

Fig. 1 illustrates a typical voltage-based loop scheme with optional peer-to-peer communication.

C. Complex Distribution Networks

The schemes referred to above are typically applied to two-feeder networks. The possible topologies are few in this network, and thus the necessary logic is limited.

Wide-area control systems that manage larger groups of feeders typically require more information to be shared via communications channels. A distribution automation controller (DAC) is commonly used to gather data and provide system-wide control functions for a group of feeders. It is often convenient to locate the DAC in a substation associated with one of the feeders being automated. However, the DAC could be located anywhere as long as the necessary communications channels are available. The controller monitors system topology, feeder loading, voltage levels, and other valuable information throughout the distribution system. The DAC provides system-oriented control decisions to achieve the interdependent control objectives listed in Section II, Subsection A.

Fig. 2 illustrates a possible network topology that would benefit from a centralized controller.

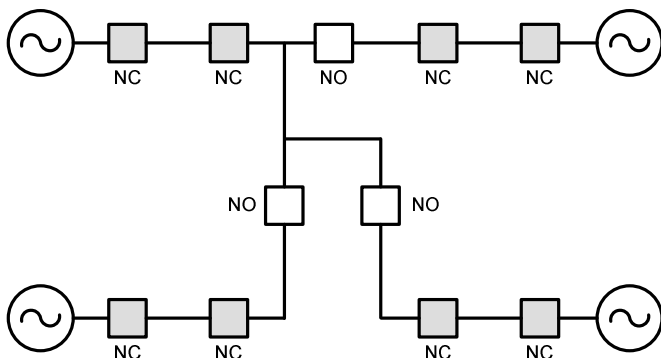


Fig. 2. Multifeder system

Control functions at the control center benefit in an even broader context by monitoring the entire distribution system. Typically, control center implementations benefit from larger computing capacity because of the centralized nature and environmental conditions of the control room. Systems at the control center usually include sophisticated software applications relating to economic drivers, optimal load flow, and asset management programs.

III. WIDE-AREA CONTROL EXAMPLE

This section focuses on one example of wide-area control used in distribution systems. The distribution automation (DA) system detects permanent faults and open-phase conditions on the distribution system. The DAC acts to isolate the affected section of the feeder and restore power to the unaffected feeder sections from the normal source. Power can also be restored from an alternate source, if available.

A. Example Distribution Network

Although the DAC can be applied to a wide variety of feeder arrangements, it is helpful to describe the system operation with respect to an example distribution network. The example network includes four sources, four feeder breakers, and twelve reclosers. Four reclosers (R3, R6, R9, and R12) are normally open, and the remaining switching devices are normally closed. The distribution network consists of radial feeders only.

The normal configuration of the example network is shown in Fig. 3.

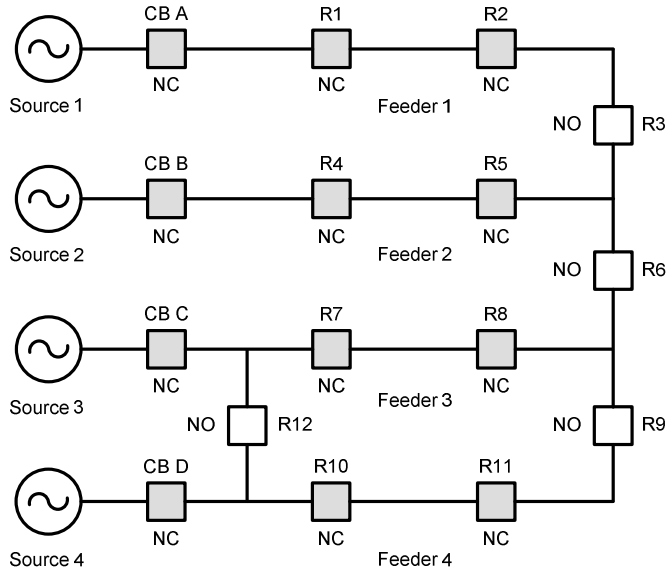


Fig. 3. Example distribution system

The distribution network is comprised of zones. A zone is defined as a section that can be disconnected from the distribution system using switching devices. The example distribution system includes the following zones: CB A-R1, R1-R2, R2-R3, R3-R5-R6, R4-R5, R4-CB B, R6-R8-R9, R7-R8, R7-R12-CB C, CB D-R10-R12, R9-R11, and R10-R11. Substation buses are also considered zones but have only one switching device (the feeder breaker) at their boundary. Each zone in the distribution system is energized from only one source at any given time. The switches in the example distribution system are circuit breakers (CBs) and reclosers. Motor-operated switches may be incorporated into the control strategy as well. Motor-operated switches are not rated to interrupt current. Care must be taken to ensure that the control system does not attempt to open a motor-operated switch when load current is present. Installing fault indicators with the motor-operated switch provides the wide-area control system with the necessary information to identify the faulted zone. If the fault is downstream of the motor-operated switch, the control system will open the motor-operated switch after an upstream device has cleared the fault. The upstream clearing device is then closed to re-energize the nonfaulted section of the system.

Each component in the distribution system has a current-carrying capacity rating. The capacity of each source is a function of the corresponding distribution transformer rating and other loads being fed by the same transformer. The circuit breakers and reclosers have equipment ratings that must be considered as well. The conductors also have summer and winter current-carrying ratings that must be considered by the control system. It is important to note that the conductor size will vary in many distribution systems. Therefore, the control system must evaluate capacity and load on a zone-by-zone basis.

The DAC will respond to permanent faults or open-phase conditions on any of the distribution system zones. For example, the protection device at R1 clears a permanent fault on Zone R1-R2. This leaves Zone R2-R3 de-energized, even though there is no fault on this zone. The DAC acts to isolate the faulted zone from the remainder of the feeder by opening R2. The DAC then restores power to the loads on Zone R2-R3 by closing R3.

If a permanent fault occurs on Source 4, the DAC isolates the faulted zone by opening CB D. In this case, Zones R9-R11, R10-R11, and R10-R12-CB D are left de-energized. The DAC must choose between two alternate feeds to restore the load. It will close either R9 or R12. To make this decision, the DAC evaluates the following:

- Load connected to the de-energized zone
- Available capacity of each alternate feed
- Live-voltage indication of each alternate feed
- Communications health to all related devices
- Abnormal conditions related to each feed

B. Control System Architecture

The DAC is a dedicated controller for an area of the DA system. The DAC includes a set of feeders in its control scope. Utilities have installed intelligent electronic devices (IEDs) for many years. IEDs, such as modern protective relays and recloser controls, provide local measurement and control capabilities. The DAC communicates with these IEDs and does not require additional interface hardware at end devices.

Fig. 4 shows the simplified control system architecture for the example distribution network. The DAC is located in the same substation as the protective relay for CB A. The DAC communicates with the CB A relay via a direct serial connection. Because the other two circuit breakers are located in other substations, the DAC communicates with them by radio connections. Similarly, the DAC communicates with all of the relevant recloser controls via radio as well. The simplified diagram shows one radio at the same location as the DAC and one radio at each of the relevant IEDs. The actual radio installation depends on several factors, such as distance, terrain, and congestion.

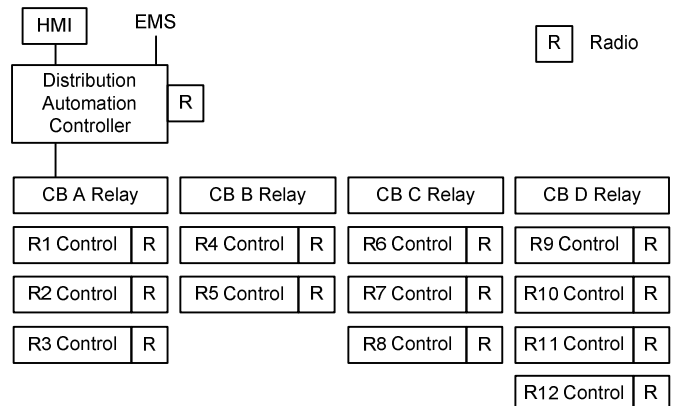


Fig. 4. Wide-area control system architecture

Protective relays and recloser controls provide the physical interface to the circuit breakers and the reclosers. These IEDs

provide the following input and output signals to the wide-area control system:

- Switch open/close indication
- Live-/dead-voltage indication
- Fault current indication
- Recloser lockout indication
- Load current
- Abnormal condition indication
- Open/close commands
- Settings group change commands

The DAC collects data and sends control commands to the protective relays and recloser controls using the DNP3 protocol. Data are transmitted from the end devices using unsolicited messages as conditions change. The DAC also polls each end device periodically to ensure that the end device is still healthy. The DAC sends DNP3 control messages as required by the automatic sequence.

The DAC includes a local human-machine interface (HMI). The HMI is not necessary for the controller to operate; however, local visualization is very helpful during initial installation and commissioning of the control system. It is also convenient for post-event analysis activities once the control system is in service. The HMI includes the following features:

- Status and control
- One-line diagram
- Alarm annunciation
- Automation sequence status
- Sequence-of-events viewer

The DAC is a node on the utility energy management system (EMS). The controller provides data to the EMS from all end devices within its scope of control. The DAC also provides information about the automatic reconfiguration sequence. Dispatchers can control individual end devices and the DAC via the EMS connection.

C. Sequence of Operation

The DAC executes a straightforward sequence. Fig. 5 illustrates the sequence of operation of the automation system.

The Initialize step is executed when the controller first turns on, when an operator disables the sequence, or when an operator issues a RESET command while the sequence is unarmed. The Initialize step acts to reset internal variables and alarm conditions. During this step, the distribution system configuration is evaluated to determine the normal operating arrangement. Once the Initialize step has executed, the sequence transitions to the Unarmed step.

The Unarmed step is executed after the Initialize step is completed successfully or if a sequence failure occurs during the Update, Analyze, Isolate, or Restore steps. The Unarmed step monitors for an operator-issued ENABLE command. If this command is detected, the sequence transitions to the Ready step. The Unarmed step also monitors for an operator-issued RESET command that, if detected, returns the sequence to the Initialize step.

The Ready step is executed when an operator enables the system. The system will also return to the Ready step once load is restored. In the Ready state, the system monitors for an

event that requires further analysis. An event may be an undervoltage indication or a fault indication reported by a recloser control or feeder relay. The event detection is supervised to ensure that events are ignored if they correlate with abnormal conditions on the related circuit, such as abnormal circuit configuration, hot-line tags, nonreclose status, supervisory control disabled, or communications failure. Once an event has been detected, the sequence transitions to the Update step.

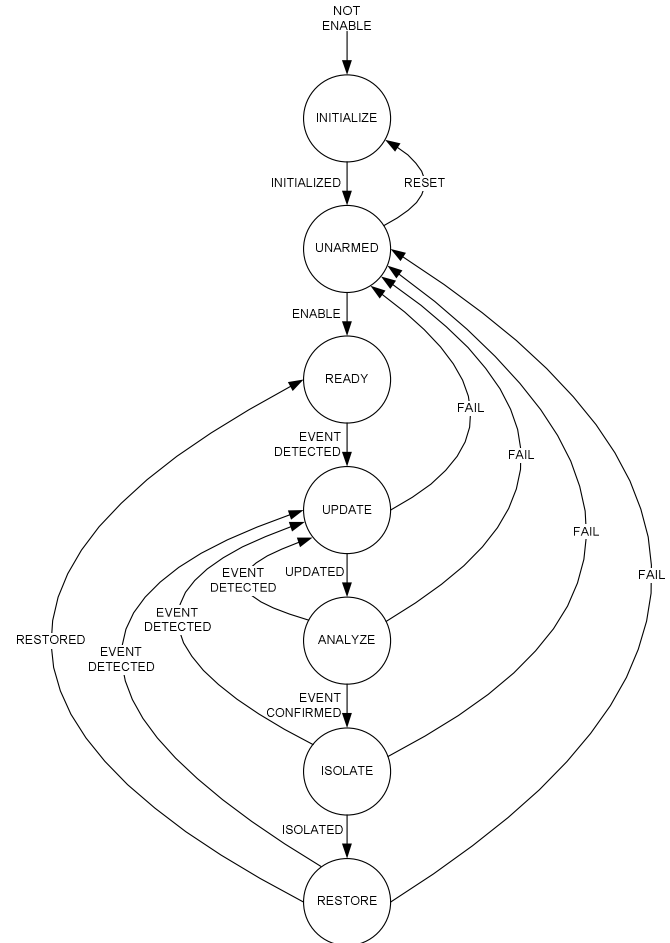


Fig. 5. Sequence of operation

The purpose of the Update step is to initiate a poll of all end devices. This is done in order to base all subsequent decisions on up-to-date information about the distribution system. Additionally, the poll during the Update step verifies that each end device is responsive. If an end device does not respond, a communications alarm is generated. Once the poll is complete, the sequence transitions to the Analyze step.

The purpose of the Analyze step is to determine if a permanent fault has occurred or if an open-phase condition exists. The analysis is supervised to ensure that it is blocked if abnormal conditions are present on the related circuit.

If the system determines that a permanent fault or an open-phase condition exists, the sequence transitions to the Isolate step. If the system determines that the event condition no longer exists, the sequence returns to the Ready step. If a new event is detected in this step, the sequence returns to the Update step for another poll of the end devices because the

new event requires the DAC to obtain new, up-to-date information.

The Isolate step is executed when the system identifies a feeder section that has a permanent fault or an open-phase condition. The purpose of the Isolate step is to open switching devices connected to the affected zone. The controller evaluates each switching device on the boundary of an affected zone to determine if it should be opened. If there are de-energized zones downstream of the affected zone and an alternate feed is available to restore the de-energized zones, the switching device is opened to isolate the affected zone from the unaffected de-energized zones. As in the Analyze step, if a new event is detected in this step, the sequence returns to the Update step for another poll of the end devices in the affected portion of the distribution system.

The Restore step is executed when the system has successfully isolated the feeder section that is faulted or has an open-phase condition. If there are de-energized zones downstream of the affected zone that have been isolated from the affected zone, the system attempts to restore these zones from an alternate feed by closing a normally open tie point connection to an adjacent feeder. Once again, if a new event is detected, the sequence transitions back to the Update step for another poll of the end devices.

Once the Restore step is executed, the sequence transitions back into the Ready step, where it will continue monitoring the system for a new event. The DAC will alarm the dispatcher with the type of event that occurred, such as an open-phase condition or a permanent fault. This alarm indication can be reset by issuing a RESET command.

D. Abnormal Conditions

There are situations when automatic reconfiguration is not desirable. The DAC considers the following to be abnormal conditions:

- Hot-line tags
- Supervisory control disabled
- Autoreclosing disabled
- Device diagnostic failure
- Communications failure
- Command failure

If an abnormal condition is present on any switching device associated with a feeder, the entire feeder is considered to have an abnormal condition. For example, if R2 in Fig. 3 has a hot-line tag present, the entire radial feeder associated with Source 1 is considered to have an abnormal condition. A feeder that has an abnormal condition is excluded from the DAC strategy. The DAC will not respond to events on this feeder, and this feeder will not be considered as a valid alternate feed.

IV. PROTECTION CONSIDERATIONS

A. Time-Overcurrent Coordination

Overcurrent protection is the predominant protection method used for distribution feeders. The principle is well understood and straightforward to implement. Engineers select

standard time-current curves, pickup values, and time dial settings to time-coordinate the operation of multiple protection devices on a radial feeder. The objective is to operate as fast as possible for faults in the primary zone, while delaying operation for faults in the backup zone. The engineer derives the protection settings from knowledge of the available short-circuit current and the desired coordination time interval between devices.

Automatic circuit reconfiguration results in system configurations that may render the protection settings ineffective. Coordination of overcurrent devices is not necessarily maintained. Power flow direction is reversed in some areas when the loads are fed from a different source. Additionally, the available fault current levels may be significantly different in the new configuration.

For this reason, some DA systems will revert to a switch mode of operation after the initial fault is detected and the distribution system has been reconfigured. These systems purposely defeat protection in devices outside the substation when the circuit is not in the normal configuration. Protection is provided solely by the feeder breaker relay in the substation. This approach removes the problem of poor coordination by removing the coordination altogether. Subsequent faults on the feeder will cause the feeder breaker to operate, even if a recloser located closer to the fault could have removed the fault. In this case, the end result is that load is unnecessarily de-energized.

Fig. 6 illustrates the operation of the protection system for systems that revert to a switch mode of operation. All five reclosers are in switch mode because of a previous fault and reconfiguration. If a subsequent fault occurs between R1 and R2 while the reclosers are in switch mode, the feeder relay at CB B will operate to clear the fault. The load on the feeder between CB B and R2 is de-energized unnecessarily if the reclosers are operated in switch mode. Note that on many distribution circuits, it may not even be possible to set the CB B relay sensitive enough to see a fault past R2 and still be set high enough to carry load. In this case, CB B would not trip, and the last section of the feeder would be unprotected.

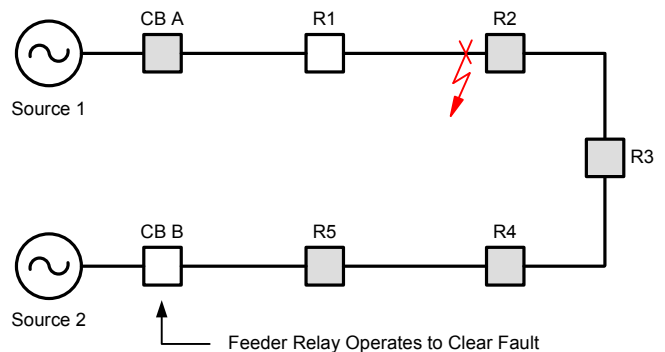


Fig. 6. Subsequent fault while in switch mode

A better approach is to have the protection functions adapt to changing conditions caused by the operation of the DAC. Modern microprocessor-based protective relays support programmable logic and multiple settings groups. Wide-area control systems that take advantage of these features can

guard against compromising the protection of the circuits. These control systems implement a step in the automatic reconfiguration sequence to validate the state of the protection system. If necessary, the control system issues commands to protective relays and recloser controls to change settings. In this way, the wide-area control system adapts the protection system to fit the new circuit configuration before the system is reconfigured. The distribution engineer must attempt to perform coordination studies on all valid operating configurations to ensure the protection settings coordinate.

Fig. 7 shows a three-source system where the DAC can change settings groups on the controls to maintain coordination after a reconfiguration. The recloser controls have multiple settings groups that can change based on their source. Fig. 7 shows that R1 and R2 are on Settings Group 1 (G1) when fed from Source 1. Similarly, R4 and R5 are on Settings Group 2 (G2) when fed from Source 2, and R7 and R8 are on Settings Group 3 (G3) when fed from Source 3.

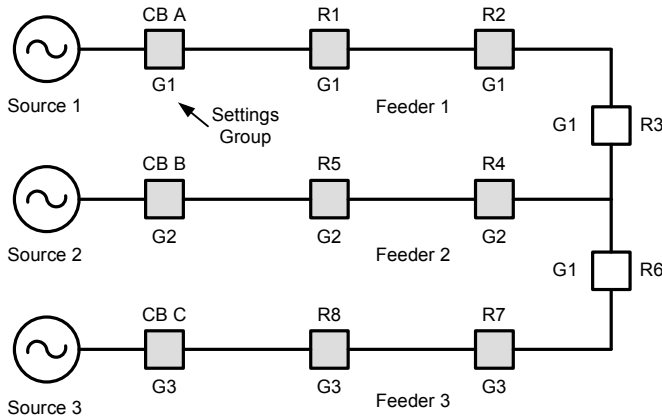


Fig. 7. Three-source system with settings groups shown

If an outage occurs on Source 2, the DAC will reconfigure the system by opening CB B and closing R3. This picks up the load that was previously fed from Source 2. In addition, the DAC will change the R4 and R5 recloser controls from Settings Group G2 to Settings Group G1 to allow coordination with the upstream recloser controls, as shown in Fig. 8.

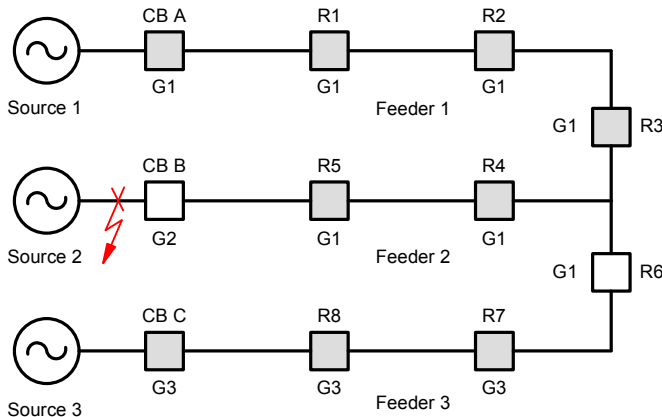


Fig. 8. Settings group changes on Feeder 2 when fed from Source 1

An outage of Source 1 would cause a similar reconfiguration by the DAC. However, in this case, recloser controls on R1, R2, and R3 would change from Settings Group G1 to Settings Group G2. This maintains coordination with the upstream recloser controls, as shown in Fig. 9.

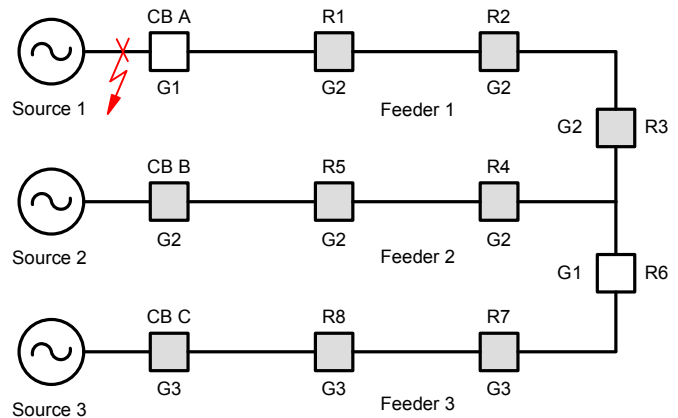


Fig. 9. Settings group changes on Feeder 1 when fed from Source 2

B. Miscoordination

In many instances, coordinating the reclosers on a feeder is a challenging task for the distribution engineer. Automating distribution systems makes circuits more dynamic in nature, creating more coordination scenarios for the distribution engineer to review compared to when circuits are static.

The system in Fig. 10 is an extreme case, prone to recloser control miscoordination.

In Fig. 10, let us assume that two outages occur at different points in time on the distribution system. A fault occurs at F1, causing an outage at Source 1. The DAC reconfigures the system by opening CB A and closing R3 so that the load on Feeder 1 is now served by Source 2. A second fault occurs at F2 and removes the ability of Source 2 to provide power to Feeder 1. The DAC isolates the F2 fault by opening R4 and closing R6 to pick up load on Feeder 1 from Source 3. The DAC changes settings groups on the controls associated with R1, R2, R3, and R6 to allow the time-overcurrent elements in the controls to coordinate for faults on the new circuit configuration now fed from Source 3.

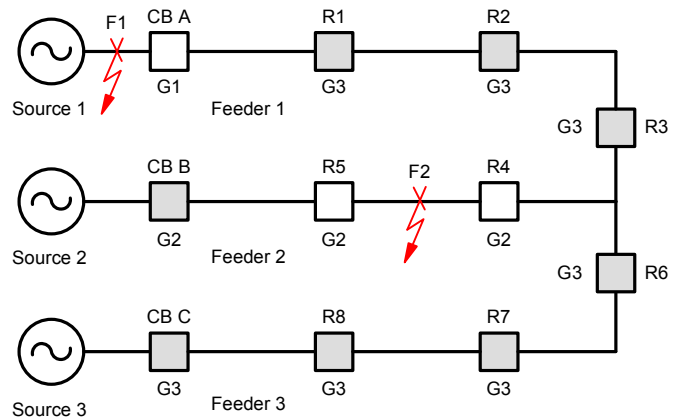


Fig. 10. Multiple fault scenario

A third wave of storms now comes through the area, and a fault occurs at F3, as shown in Fig. 11. Instead of the control on R1 tripping for the fault, the control on R7 miscoordinates with R1 and trips for the fault at F3.

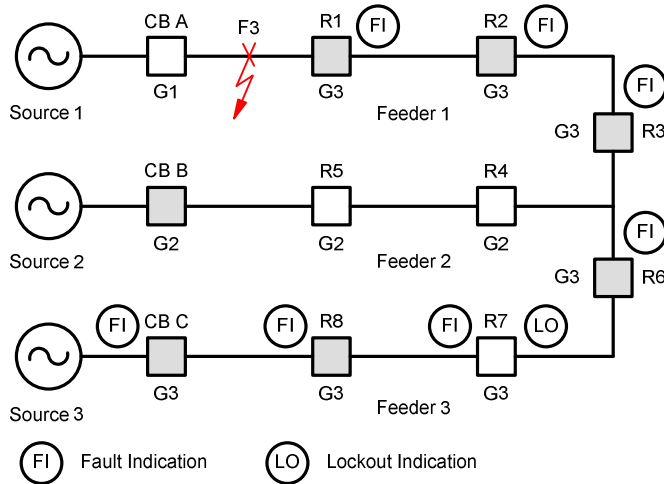


Fig. 11. Miscoordination of protection devices

With so many reclosers in series in this scenario, it is difficult to get coordination on the feeder without exceeding maximum allowable clearing times on the feeder sections close to the source.

R7 goes through its reclosing cycle and then locks out. The automation logic in the DAC detects that a miscoordination occurred by determining the fault location on the circuits from the fault indicators on each recloser. The DAC checks that the correct recloser opened to clear the fault and finds that R7 should not have opened for the fault at F3. The DAC also detects that R7 locked out for a fault that was downstream of the other reclosers on the circuit. With the miscoordination logic enabled, the DAC opens R1 to isolate the fault and then closes R7 to pick the load back up again. Additionally, the DAC alarms for the miscoordination event and provides data that engineers can use to analyze and, perhaps, resolve the problem.

There are several causes of miscoordination, including settings errors, misapplications, erroneous short-circuit studies, and unforeseen circumstances. Occasionally, distribution engineers have to deal with long circuits with several reclosers on the main line. In order to achieve a reasonable clearing time at the station breaker, very small coordination margins may be used. In these cases, some amount of miscoordination is expected. The miscoordination logic in the DAC can be very beneficial in restoring load in these situations when a miscoordination occurs. Miscoordination detection is particularly important in unusual situations that may be difficult to properly plan for.

Wide-area control systems have a larger scope of measurement than the individual relays in the network. A DAC will detect miscoordination events based on circuit topology, fault indications, and lockout indications.

C. Voltage and Loading

When switching load from one circuit to another, a dispatcher verifies that the circuit is capable of supplying the additional load. The dispatcher considers the voltage level of the receiving circuit, as well as the available capacity compared to the amount of load being transferred. An automation system acts automatically and does not give the dispatcher the opportunity to validate these conditions. The DAC must perform these basic checks to avoid overload and excessive voltage drop conditions.

Ideally, voltage should be measured on both sides of all normally open tie points in the network. This allows the dispatcher or the control system to check for healthy voltage levels on adjacent feeders as part of the process of choosing an alternate source to pick up load. If voltage is not measured directly at the tie point, measurements may be considered from devices on the same section.

In Fig. 12, the protection device at CB A has cleared a fault between CB A and R1.

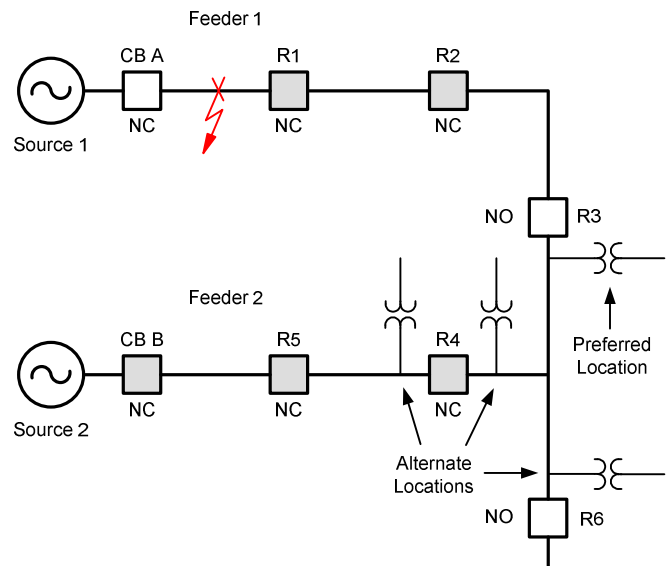


Fig. 12. Locations of voltage indication

The loads between R1 and R3 are de-energized. These loads could be re-energized from Feeder 2 by opening R1 and closing R3. The dispatcher checks to ensure that healthy voltage is present on the alternate feeder. The preferred location to check for voltage is on the Source 2 side of R3. However, if this voltage is not measured, there are alternate locations that could be examined to determine if there is healthy voltage in the zone. Voltage measurements at R6 or R4 can provide live-voltage indications. The wide-area control system is aware of all possible locations and will automatically select the best location for the situation.

Inadvertent overloads cause thermal damage to circuit conductors. Wide-area control systems must consider loading before automatically reconfiguring the network. The control system should consider the following three aspects of loading:

- Amount of capacity available on alternate feeds
- Amount of load to be re-energized
- Load changes over time

It is important to note that conductor sizes may vary throughout the distribution system. Therefore, the control system must evaluate the capacity and load on each section of the feeder to determine the overall capacity of the alternate feed.

Relays and recloser controls measure current. The DAC collects these measurements and performs simple arithmetic to calculate the amount of load that is connected to each section in the network. The load is simply the current entering the section minus the current exiting the section. When a fault occurs that leaves parts of the system de-energized, the control system uses its memory of the load prior to the fault while it attempts to find an alternate feed.

Overloads can develop over time because of daily load profile. In Fig. 13, Source 4 is lost. In this scenario, an automatic reconfiguration at 5:00 a.m. results in no overload conditions when R12 closed to pick up the de-energized load. However, by early afternoon, the conductors at the R12 tie point are reaching their load limit. The DAC for this area automatically rebalances the load by transferring some of the load now flowing through the R12 tie point by opening R10 and closing R9 to alleviate the overload that develops over time. In situations where load transfer is not possible, the control system can shed less critical loads in order to preserve more critical loads while mitigating the overload condition.

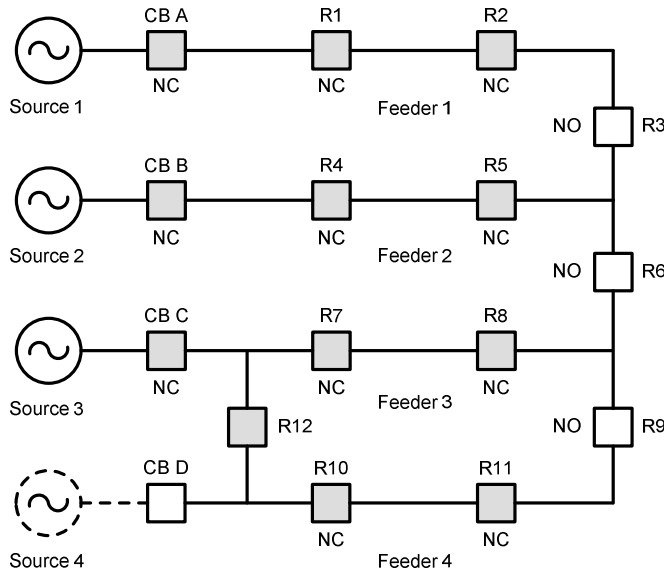


Fig. 13. Reconfigured circuits overload later in the day

V. AUTOMATING LARGE AREAS WITH MULTIPLE DACS

A DAC has a finite number of end devices it can efficiently poll. When an automation area becomes large enough to exceed the capabilities of a single DAC, additional DACs can be added, as shown in Fig. 14. In this example, DAC 1 controls end devices in Area 1, and DAC 2 controls end devices in Area 2. If these two areas have a common electrical tie, like R4, which is controlled by DAC 2 in Area 2, data between the DACs will be exchanged to determine the status of the sources in both areas. Both DACs will also be aware of their available capacity for picking up additional load. Sharing

data between the DACs that have electrical ties between their automation areas allows a seamless integration of the DACs in a much larger area of automated circuits. By sharing data across boundaries between DAC areas, many DACs in very large automated areas can function like a single controller. The advantage of using multiple DACs is that they can be placed in the heart of the area that is controlled rather than in a remote centralized location. Locally, end devices that are on a boundary between DAC areas, like R3, R4, and R6 in Fig. 14, can still function as if they were under the control of a single DAC. This approach also minimizes the impact of the failure of any one DAC on the entire area.

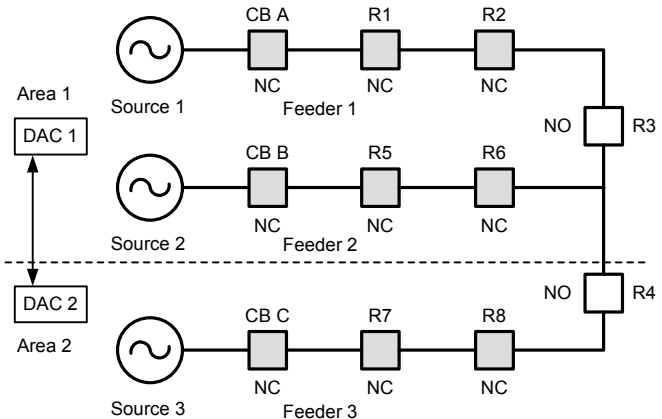


Fig. 14. Large automated areas with multiple DACs

VI. SYSTEM OPERATION CONSIDERATIONS

Wide-area control systems affect the operation of power distribution systems in several ways. The effects can be described in terms of day-to-day operations and control system design choices.

A. System and Safety Checks

One way to evaluate the effects of wide-area control on operations is to consider what a dispatcher would consider. When transferring load from one feeder to an alternate feeder, a dispatcher will consider the impact that the operation will have, asking basic but essential questions, such as:

- Will the operation result in exceeding predefined system limits?
- Will the operation result in potentially unsafe conditions?

Failure to consider these questions may result in equipment damage or injury to personnel. If a wide-area control system automatically transfers load from one feeder to an alternate feeder, the dispatcher is no longer in the decision-making path. If the control system does not have appropriate checks, undesirable operations are inevitable.

For this reason, the control system must implement system checks to determine if the alternate feeder is capable of feeding the loads to be transferred (this was discussed in Section III, Subsection A). The control system must also implement checks to ensure that the operation does not conflict with any crew activities. One way to address this is to

have the control system monitor for any indications of crew activity, such as the following:

- Hot-line tags
- Autoreclose disabled
- Supervisory control disabled

The wide-area control system can easily monitor indications from all switching devices on the feeder. If any of these indications are present on any switching device, the operation is blocked. In this way, the control system can avoid automatic operations related to feeders where utility crews are working.

Additional checks can guard against other undesirable operations. For example, a communications failure to one recloser on a feeder should block all automatic operations related to that feeder. When a communications failure occurs, the control system no longer has visibility and cannot tell if indications of crew activity are present at the offline device.

B. Feeder Breaker Control Inhibit

In many cases, wide-area automatic control systems are implemented on parts of the distribution network that previously were not remotely controlled by the dispatcher. Dispatchers may not have concerns about automatic operation of devices outside the substation. However, because the feeder breaker has been under their exclusive control in the past, dispatchers may have concerns about allowing an automatic system to control it.

Many strategies can still be implemented by controlling only reclosers and motor-operated switches outside the substation. However, automatic control of the feeder breaker allows better performance of the control strategy in some situations. For example, if a loss of voltage occurs on the substation bus, the control system can automatically open the feeder breaker. The entire feeder can then be re-energized from an alternate source. However, if control of the feeder breaker is not allowed, the first recloser outside the substation will be automatically opened instead of the feeder breaker. The feeder beyond the first recloser is then re-energized from an alternate source. In this case, the feeder section between the substation and the first recloser is left de-energized unnecessarily.

Automatically controlling the feeder breaker may not be a concern at some utilities. If it is a concern, the wide-area control system should support a control-inhibit function that adapts the control strategy to fit the operational comfort level. As time passes and the control system proves itself to be reliable, dispatchers will gain confidence in the system. Removing the “inhibit” from the feeder breaker is a simple task.

C. Return to Normal

Wide-area control systems will automatically reconfigure the distribution network to restore load or relieve potential overload conditions. Reconfiguration may include several switch operations and changes to protection settings in multiple devices. These operations are executed in a specific sequence. Additionally, the system performs validation checks

to ensure system limits are not exceeded and safety is not compromised.

At some later time, a dispatcher will have to return the distribution network to its normal arrangement. The dispatcher must perform a sequence of operations similar in complexity to the sequence performed by the control system in the initial reconfiguration. In the case of complex networks with several tie points, this can be a time-consuming task. Because the control system may have changed protection settings in several devices in order to preserve coordination, the dispatcher must know what the normal protection settings should be. The dispatcher will typically not be aware of this level of detail.

In order to address this issue, the wide-area control system should include a return-to-normal function. This function allows the dispatcher to initiate the sequence to return the network to its normal arrangement with a single command to the control system. The control system will then execute the appropriate sequence of operations to return the switches and protection settings to the normal arrangement.

The return-to-normal function is also useful when returning back to a normal configuration from a temporary reconfiguration of a feeder for maintenance or a line section outage. When the work is finished, the return-to-normal function can be executed from the dispatching center to return to the normal configuration of the feeder.

Additional return-to-normal functionality can be built into the automation system to make changes to the distribution system very easy to manage in the DAC. If a manual feeder reconfiguration becomes permanent rather than temporary, the dispatcher can issue a command to the controls on the feeder to make this configuration the normal configuration. This feature avoids any DAC reprogramming and allows the system to return to this new configuration as the normal configuration.

D. Equipment Interface Flexibility

Some wide-area control systems utilize specialized devices to interface with the primary apparatus in the system. This approach results in control device duplication in the system, which can ultimately drive up the costs of installing and operating wide-area controls.

Well-designed wide-area control systems leverage existing assets. Modern protective relays and recloser controls have the necessary monitoring, control, and communications capabilities. The DAC should interface to these existing devices directly. Typical wide-area control strategies, such as automatic reconfiguration, require only a small set of data and control points for each device in the system. The data requirements are well within the capabilities of modern IEDs already in use in many distribution systems.

Interfacing to existing devices reduces training costs compared to those associated with introducing new equipment. Using existing IEDs as the field devices reduces the amount of training required to familiarize line crews with the wide-area control strategy. For example, if existing recloser controls are used as the end devices in the wide-area

control system, field crews can be trained on a few new indications on a device with which they are already familiar.

E. Straightforward Implementation

Some wide-area control systems require significant amounts of detailed engineering to adapt the control system for specific installations. This tendency can quickly consume engineering resources and severely reduce the number of feeder groups that a utility is able to automate. There are many potential differences between installations, including the following:

- Number of sources
- Number of tie points
- Number of switching devices
- Diversity of device types (e.g., breakers, reclosers, motor-operated switches)
- Location and number of voltage measurements (e.g., source and/or load side of switching device)
- Capacities of feeder sections

In order for a utility to gain widespread advantages from wide-area automatic control, automation strategies must be easy to implement on diverse circuit arrangements.

F. Operator Interfaces

A side effect of automating the distribution system is that more data become available to the control center. Information that was previously islanded in standalone recloser controls becomes accessible via the supervisory control and data acquisition (SCADA) interface to the DAC. This is a great benefit because it adds to the situational awareness of the dispatcher. However, it can also have a negative effect if the data are not organized. Some systems forward large amounts of unorganized data to the control center. In the end, this approach is not sustainable because operators become frustrated. They are forced to sift through large amounts of data to find the one piece of information that is important at the time. The negative impact of large amounts of unorganized data becomes more pronounced as more feeders become automated.

A more sustainable approach is to forward a small subset of the available data to the EMS to give the dispatcher better situational awareness, critical indications, and alarms from the control system. A local HMI at the DAC can be used to log detailed sequence-of-events data for post-event analysis without burdening the connection to SCADA. The addition of satellite-synchronized clocks at each recloser location ensures that all sequence-of-events data are precisely time-tagged to aid with post-event analysis. The local HMI can play a critical role in determining how the control system is performing.

VII. COMMUNICATIONS FAILURES IN DA SYSTEMS

A. DA Is Dependent on a Solid Communications Infrastructure

Communications systems associated with DA applications in electric utilities commonly utilize unlicensed, spread-spectrum radios or cellular modems. The geographical area these communications systems cover is often quite large,

particularly if the setting is rural. Radio communications systems are the least expensive type of communications system to apply in these cases. Although a fiber-optic system is preferred, the installation of a fiber-optic system that encompasses the end devices is cost-prohibitive in most cases. Typical communications systems might utilize some fiber-optic-based communication on the backbone path of a communications system, while radio links communicate to the end devices. Many radio systems operate at relatively low data rates and can suffer short outages while moving data. In these low-speed systems, the DA system performance is greatly dependent on the performance of the communications system. If data communications are delayed, it is very likely that system reconfiguration will also be delayed if an outage occurs on the distribution system at that time.

Many of the short-duration outages that can occur in a radio communications system are of little or no consequence to the overall operation of the DA system. A retry by the DAC will likely capture the data on the next poll. However, communications system outages that have time spans of minutes are of concern to distribution, power quality, and asset planning engineers because an outage could occur at the time a link in the communications system is down. DA systems are dependent on communication to operate properly when an outage occurs. Loss of communication to a single device is significant enough to take the DA system offline for a particular feeder because the status of that device is no longer available to the DAC.

B. Communications System Path Outages

One system was analyzed to determine how the communications system performed over an 81-day period. Findings show that one of the paths in the communications system was down eight times for a total outage time of approximately 56 minutes. The longest outage time was 10 minutes and 45 seconds. Extrapolating these data to a period of a year indicates that this same communications system could be down for as long as 252 minutes a year. It is this type of communications system outage information that raises concern about the reliable operation of the DA system. It also causes us to ask what can be done to allow a reconfiguration of the distribution system during an outage if, at the same time, the communications system is not fully functional. This scenario motivated DA engineers to develop a backup system that can engage if a power outage occurs when a link in the communications system is down. The idea is to keep the DA system as functional as possible, even when multiple communications links are down. This concept allows the installed DA system assets to be better utilized, provides additional benefits to customers by reconfiguring the power system, and restores power when the communications system may not be fully functional.

Ideally, the backup system should monitor the communications links in some way to detect when a link is lost. After a time delay, the backup system needs to automatically place itself in service when a communications link goes down and disable itself when the communications

system returns to normal. No intervention from the distribution control center is needed. An alarm point indicates that the DA system is offline in a particular area of the distribution system as a result of a communications link failure somewhere on the DA system.

To eliminate the need for any user intervention, some mechanism is needed to detect a problem with the communications system and cause the system to transfer from full DA to a backup system. Similar logic is needed to detect when communication returns to normal in order to allow a transfer from the backup system to full DA. Both the DAC and the end device need to know the status of the communications link between them. This allows them to transfer to the backup system when the link goes down.

To keep track of the link between the DAC and the end devices, the DAC sends a keep-alive bit to those devices. The end devices look for this bit to arrive at a periodic rate. When the bit is no longer detected after a reasonable time period, the end device or devices conclude that the communications link to the DAC has been lost. Logic in the end device then switches the device from DAC control to the backup local control logic resident in the end device.

The DAC also has backup logic that allows it to recognize that data from the current poll of the remote device are no longer refreshing the data from the previous poll of the remote device. Using this technique, the DAC determines when a communications link has gone down. With this information and the configuration of the distribution system, the DAC then relinquishes control of the other end devices in the zone where the communications link is lost and commands those devices to begin running on local control.

With both the DAC and the end device detecting a problem with the communications link between them, they can both take action and go into a backup mode. This not only allows the device that lost the communications link to run on its own local logic but also allows devices surrounding it to begin operating on their local control logic as well. Even though the communications links to these other devices are functional, the DAC no longer controls them, because it does not have enough information about the power system to make intelligent decisions to automatically reconfigure it. The devices that the DAC must relinquish control over, from a DA perspective, are now permitted to operate from their local control logic. This technique allows the end devices to be able to still reconfigure the power system if an outage occurs.

By adding loop scheme logic to the end devices, they can function to reconfigure the distribution system when an outage occurs and communication is down. However, they do not reconfigure the system as intelligently as the DAC, because the DAC has information about the distribution system that the remote devices do not have when an outage occurs.

This scheme provides distribution engineers with backup logic that they can enable to automatically allow power system reconfiguration when a communications link is down in the DA system. Without a backup system, the DAC only

reports the failure of the communications link. It does not take any action to reconfigure the distribution system, because it does not have enough information to make good decisions about how best to reconfigure. Adding communications monitoring logic and backup logic in the local devices and the DAC provides a means to utilize most of the components installed for the DA system, even though the system might not be fully functional. The backup logic scheme provides better utilization of the dollars spent on the DA system by providing a means to reconfigure the distribution system during an outage, even if the communications system is not completely functional.

C. Backup Logic Schemes

A number of utilities use loop scheme logic on their distribution systems. Loop scheme logic does not require communications between the remote devices or to a DAC. The logic simply senses the voltage at the device and starts timing from the point when voltage is lost on the distribution system. A typical loop scheme is shown in Fig. 15.

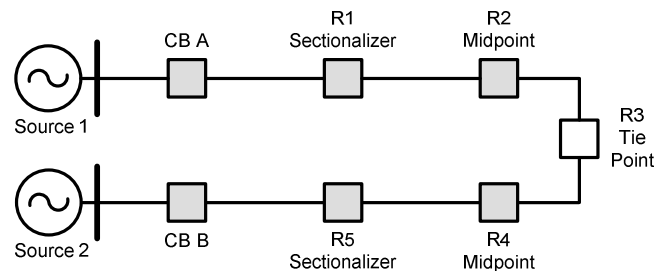


Fig. 15. Typical loop scheme configuration

As shown in Fig. 15, the reclosers are programmed with sectionalizer, midpoint, and tie point logic.

Sectionalizer logic detects a loss of voltage on the source side of the recloser. After a predetermined time, the recloser control opens the recloser to isolate the source-side line section. Closing the recloser with voltage on the source side resets the logic.

Midpoint logic detects a loss of voltage on the source side of the recloser. After a predetermined time, the recloser control, as an option, can change settings groups to maintain coordination on the loop, if necessary. The recloser control has a settable window of time to lock out if a trip occurs (one-shot mode). For a permanent fault on the source side of the recloser, the control trips and locks out when the tie point recloser closes to re-energize the line.

Tie point logic detects loss of voltage on either side of the recloser. After a predetermined time, the recloser control, as an option, changes settings groups. The recloser control has a settable window of time to lock out if a trip occurs (one-shot mode). After a predetermined period of time, the recloser closes. Closing into a fault results in a trip and lockout of the control.

Consider the following fault scenarios to understand how these modes operate to reconfigure the feeders.

In Fig. 16, a permanent fault occurs between CB A and R1. CB A goes through its reclosing cycle and locks out. The sectionalizer logic in the R1 control recognizes the loss of voltage on the source side and opens after a time delay.

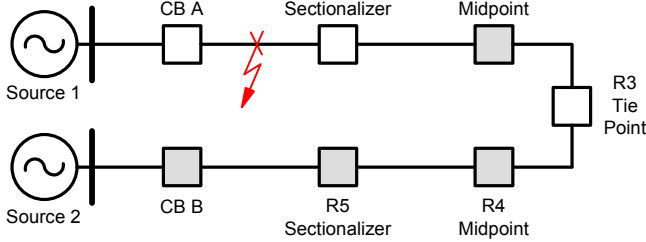


Fig. 16. Sectionalizer logic opens R1 after a loss of voltage

The tie point logic in the R3 control also senses the loss of voltage on the Source 1 side. The logic checks the voltage on the Source 2 side and, after a time delay, initiates a close command to the recloser. This restores the load on the line sections from R1 to R2 and R2 to R3, as shown in Fig. 17. Note that loop scheme logic in the controls for R2 and R3 can also be set to provide a settings group change before the control on R3 issues a close command to R3. A settings group change could be needed to maintain coordination of the time-overcurrent curves in the controls on these reclosers.

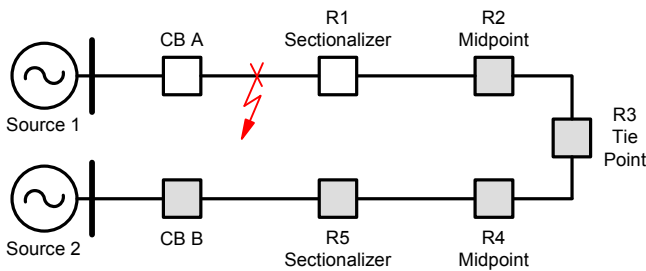


Fig. 17. Tie point logic closes R3 after a loss of voltage

Fig. 18 shows a permanent fault between R1 and R2.

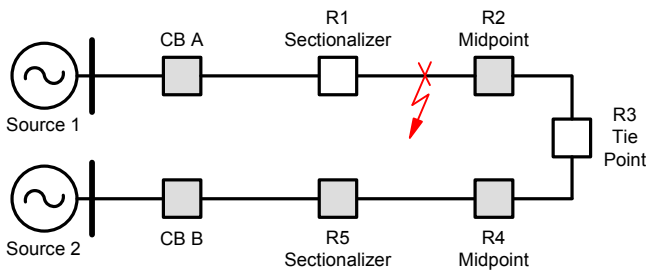


Fig. 18. Midpoint logic allows fault isolation when R3 closes

R1 goes through its reclosing cycle and locks out. The midpoint logic in the control for R2 recognizes the loss of voltage on the source side and goes into one-shot mode after a time delay. This sets up the means to isolate the fault when R3 closes after a time delay that is coordinated with the time delay for the one-shot mode at the midpoint recloser.

The tie point logic in R3 senses the loss of voltage on the Source 1 side. The same logic checks that voltage is present on the Source 2 side and initiates a close command to R3. R2 trips and locks out when R3 closes into the permanent fault.

This restores the load on the line section from R2 to R3, as shown in Fig. 19.

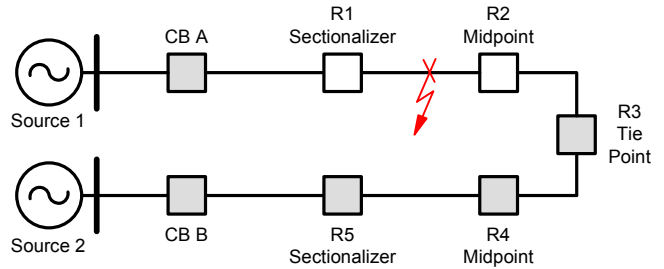


Fig. 19. R2 trips and locks out when R3 closes

A fault can occur on the line section from R2 to R3, as shown in Fig. 20. The control for R2 goes through its reclosing cycle and locks out. As before, the tie point logic in R3 senses the loss of voltage on the Source 1 side. After a time delay, the logic checks for voltage on the Source 2 side and issues a close command to R3. Because a tie point recloser is operated normally open, the reclose logic in the control is initially in the lockout state. The tie point logic has a settable time window for the control to remain in a one-shot mode. Upon closing into the permanently faulted line section from R2 to R3, the recloser trips. The recloser remains open, as shown in Fig. 20, and the control remains in lockout mode or in the lockout state.

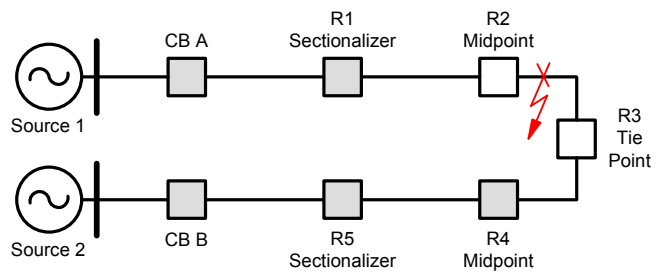


Fig. 20. R3 closes into a fault, trips, and locks out

Now that it is understood how the loop scheme logic functions for faults on the loop, Fig. 21 shows how to overlay the two distribution feeders with a DA system. The DAC has communications links to the five reclosers and the two circuit breakers. As long as the communications links are functional, the DAC can reconfigure the distribution system intelligently if an outage occurs.

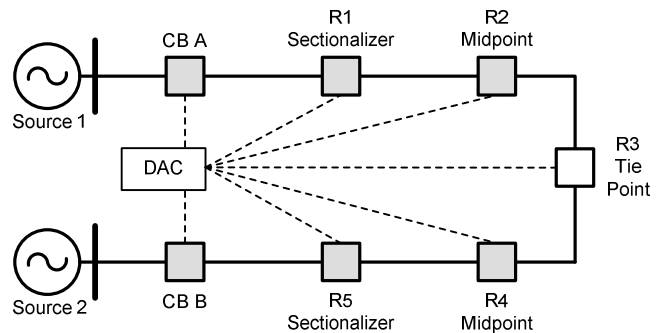


Fig. 21. DAC uses communications links to control the reclosers on the loop

In Fig. 22, assume the communications link between R2 and the DAC fails. After a time delay, both the DAC and the R2 control recognize that the communications link between them is down. The control for R2 changes settings groups to go out of DA mode and into loop scheme mode using midpoint logic.

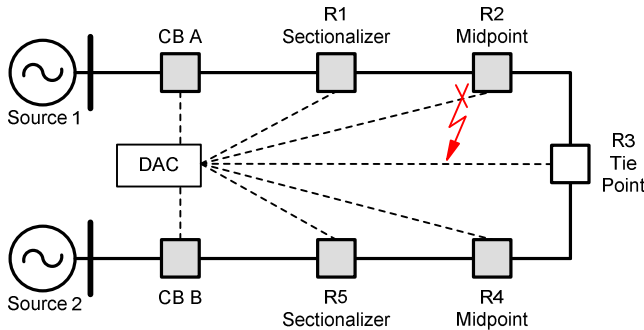


Fig. 22. Communications link failure to R2

The DAC also sends commands to the other four recloser controls to change their settings groups from DA to loop scheme settings. This puts the entire loop into loop scheme mode. With the loop recloser controls using backup loop scheme logic, the loop can still reconfigure if a permanent fault occurs.

A common question about the backup scheme has to do with the period of time the DA system is transitioning from full DA to the backup loop scheme logic caused by a communications link failure. A fault during that transition period would seem to leave the system in a vulnerable state, not allowing loop scheme logic to operate properly. During this time, the control that lost communication with the DAC is timing to go into backup mode. Also, the DAC is attempting to reestablish the communications link that was lost. When the DAC fails to reconnect with the end device, it begins putting the controls on the loop in backup mode. This does not usually happen at the same time that the control that lost its communications link goes into backup mode. If the power system is quiescent, this does not matter. However, if the power system faults during this transition time, the coordination of the timers in the controls on the loop could become unsynchronized. To keep this from happening, the controls on the loop locally sense the loss of voltage on the line and start their timers at that point. As long as the deadline timers are set long enough to allow the controls on the loop to go into backup mode before they time out, the timers in the controls around the loop remain coordinated to isolate the faulted line section using backup logic.

Even though one of the communications links is down, the DAC continues to poll all of the controls. Also, the R2 control continues trying to send data requested from the DAC. Once the data make it through the communications system, the DAC recognizes the link is back up and begins changing the settings groups in the controls back to their DA settings groups so that full DA is functional again. As can be seen from the descriptions of the operations, this happens automatically, without user intervention.

D. Using Backup Logic on Complex Distribution Systems

As noted earlier, loop schemes that have no communication associated with them are more prevalent in lower density areas of load. Higher densities of load on feeders will typically have more tie points than just one. As these tie points increase, the complexity of the distribution system increases. The DAC can handle the complexity, but it becomes more of a challenge when using backup logic that would typically be applied on feeders with just one tie.

This paper will not go into applications for more complex systems. See Section X for further reading detailing complex DA systems.

On circuits where multiple ties are available, more thought and care are needed when applying backup logic. It is likely that not all of the tie points will have backup logic enabled on their local controls. Also, the controls that do have backup logic enabled may only allow closing when one side of the tie is hot and the other is not. By being selective on which circuit ties have backup logic enabled and which source it is permitted to use, backup logic can be applied on more complex systems so that feeder reconfiguration is still an option if an outage occurs when a communications link is down.

VIII. RECOMMENDATIONS

The following recommendations come from the discussions presented in this paper:

- Change protection settings groups in relays and recloser controls to preserve effective coordination after circuit reconfiguration.
- Supervise wide-area controls with voltage measurements to avoid inducing excessive voltage drops.
- Supervise wide-area controls with capacity and load measurements for individual feeder sections to avoid overloading.
- Use a wide-area controller to detect miscoordination of protection devices and restore loads de-energized because of miscoordination.
- Supervise wide-area controls with hot-line tag, supervisory control disable, and autoreclose disable indications to avoid operating switching devices where crews may be at work.
- Automatically exclude feeders that present any abnormal conditions from the control scheme.
- Specify an automated return-to-normal function to assist the dispatcher after repairs have been made.
- Specify a control-inhibit function to allow dispatchers exclusive control over the feeder breaker.
- Reduce costs associated with installing, commissioning, and operating the wide-area control system by incorporate existing relays and recloser controls into the wide-area control system where possible.

- Forward data from DACs to the utility EMS to provide expanded visibility. However, exercise diligence to avoid overloading the operators with extraneous data.
- Implement a local HMI with the DAC to aid with commissioning, training, and post-event analysis.
- Pass pertinent data between DACs in different automation areas when there is an electrical tie point that connects the two areas and is controlled by one of the DACs.
- Consider using backup logic in the local controls to allow circuit reconfiguration if a communications link goes down.

The future promises more advanced control algorithms to accommodate distributed generation and provide security assessment, demand management, and other valuable functions in distribution networks. There is little doubt that sophisticated automatic control systems are, and will continue to be, important factors in the mission to deliver high-quality, reliable power. The designers and users of these sophisticated systems must exercise diligence to avoid potential pitfalls.

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- [2] J. Roberts and K. Zimmerman, "Trip and Restore Distribution Circuits at Transmission Speeds," proceedings of the 25th Annual Western Protective Relay Conference, Spokane, WA, October 1998.
- [3] G. Hataway, T. Warren, and C. Stephens, "Implementation of a High-Speed Distribution Network Reconfiguration Scheme," proceedings of the 32nd Annual Western Protective Relay Conference, Spokane, WA, October 2005.

X. FURTHER READING

R. Greer and J. Schnegg, "Loss-of-Communications Backup Logic for Distribution Automation Schemes," proceedings of the 12th Annual Western Power Delivery Automation Conference, Spokane, WA, April 2010.

XI. BIOGRAPHIES

Richard Greer received a BSEE from Virginia Polytechnic Institute and State University in 1992. In 1999, he earned an MBA from Radford University. He began his career in 1993 as a distribution engineer with Appalachian Power Company in Pulaski, VA. In 2001, he joined Siemens Power Transmission and Distribution in Wendell, NC, as a recloser application engineer, specializing in the integration of reclosers into distribution automation schemes. In March 2006, he returned to American Electric Power (AEP) in Roanoke, VA, as an asset planning engineer and now serves as an application engineer in the Grid Management Deployment Department at AEP. He is a registered professional engineer in the state of Virginia.

Will Allen received a BSEE from the University of Alberta in 1993. He has experience in the fields of industrial control systems and power system automation. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2000 as an automation engineer and served several years as an integration application engineer. Will currently serves as a senior engineer in the SEL Engineering Services Division. He is a member of the IEEE and a professional engineer in the provinces of Alberta and Ontario and the state of Washington.

Jim Schnegg received a BSEE from The Ohio State University in 1976. He worked at Goodyear Atomic for four years as a production engineer at a uranium enrichment plant in Ohio. In May 1980, he began his career as a protection engineer with American Electric Power, where he held various positions in the protection and control of stations and transmission systems. In May 2000, he joined Schweitzer Engineering Laboratories, Inc. as an application engineer and currently serves as a senior application engineer. He is a registered professional engineer in the state of Ohio.

Andrew Dulmage received a BSEE from The Ohio State University in 2009 with a specialization in power and digital logic. In 2008, he interned for FirstEnergy, working mainly on transmission line protection. In early 2009, he interned for Schweitzer Engineering Laboratories, Inc., becoming a full-time employee in November 2009. He is currently an associate application engineer, focusing on distribution automation.