Special Report

Effect of Distribution Automation on Protective Relaying

Sponsored by the
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Effect of Distribution Automation on Protective Relaying

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1 Introduction

1.1 Assignment

Produce a special report describing the effect of Distribution Automation on Protective Relaying.

1.2 Summary

Distribution Automation (DA) is part of today's evolution of the distribution system. Many utilities already have some Distribution Automation applications (e.g., remote controlling of feeder switches and breakers, automatic reconfiguration, fault detection, fault location, voltage and reactive power control, Advanced Metering Infrastructure (AMI), etc.) and the trend is undeniable and expanding.

Modern protection technology provides capabilities that can be used to optimize network operation in coordination with DA applications. Certain DA application deployments impact the system configuration and therefore may have some impact on protective relaying.

This document expresses some thoughts on this matter by providing a brief history, describing how various schemes can affect relaying, describing the effect on relay applications and settings, and concluding with the impact on system maintenance.

1.3 Purpose

The purpose of this document is to explore the effect on protective relaying when distribution automation (DA) is applied on a primary, non-network, distribution system. For the purpose of this document, DA is defined as the sectionalization and reconfiguration of distribution circuits, including the use of automatic or remote-controlled transfer switches, line reclosers, fault interrupters, sectionalizers, and / or automated capacitor controls. Line fuse operation may be impacted after reconfiguration and the consequences of a misoperation should be considered. However, detailed discussion on fusing is outside the scope of this paper.

1.4 Definitions

Automatic Circuit Recloser: A self-controlled device for automatically interrupting and reclosing an alternating-current circuit, with a predetermined sequence of opening and reclosing followed by resetting, hold-closed, or lock-out operation. Also abbreviated as “recloser”.

Coordination of Protection: The process of choosing settings or time delay characteristics of protective devices such that operation of the devices will occur in a specified order to minimize customer service interruption and power system isolation due to a power system disturbance.

Distribution Automation: A technique used to limit the outage duration and restore service to customers through fault location identification and automatic switching.

Distribution Management System: Provides for centralized visibility and control of the distribution assets with enhanced decision-support capability that will assist in the day-to-day operations of the distribution system.

Distributed Resources: Power sources such as generators, photovoltaic units, fuel cells, battery storage, etc., connected on distribution circuits and dispersed throughout the utility distribution system.

Distribution Network: an interconnected group of circuits, being operated with multiple active sources.

Loop Circuit: A type of distribution circuit with two or more sources, usually separated by an open switch.

Radial Circuit: A type of distribution circuit fed from a single source.

Sectionalizing Switch: A device which may provide any of a number of switching functions connecting or disconnecting one or more circuits or circuit sections. Normally closed (NC) sectionalizing switches are placed along the main path of a feeder and in taps off of the feeder. Normally open (NO) sectionalizing switches, sometimes referred to as tie switches, are placed between two feeders.

Supervisory Control: A form of remote control comprising an arrangement for the selective control of remotely located units by electrical means over one or more common interconnecting channels.

Supervisory Control and Data Acquisition System: A system operating with coded signals over communication channels so as to provide control of remote equipment (using typically one communication channel per remote station). The supervisory system may be combined with a data acquisition system, by adding the use of coded signals over communication channels to acquire information about the status of the remote equipment for display or for recording functions.

Switch: A device designed to close or open, or both, one or more electric circuits.

> Note: A switch is required to carry load current continuously and also abnormal or short-circuit currents for short intervals as specified. These devices have no load-break ability if they are not equipped with a load-breaking means.

Zone of Protection: That segment of a power system in which the occurrence of assigned abnormal conditions should cause the protective relay system to operate.

1.5 Key Abbreviations and Acronyms

AMI	-	Advanced Metering Infrastructure
DA	-	Distribution Automation
CT	-	Current Transformer
DCB	-	Distribution Circuit Breaker
DER	-	Dynamic Equipment Rating
DNP3	-	Distributed Network Protocol
DMS	-	Distribution Management System
DR	-	Distributed Resource
EM	-	Electomechanical
FCI	-	Faulted Circuit Indicator
FLISR	-	Fault Location, Isolation and Service Restoration
HMI	-	Human Machine Interface
IED	-	Intelligent Electronic Device
IP	-	Internet Protocol
IVVC	-	Integrated Volt VAr Control
LTC	-	Load Tap Changer
PT	-	Potential Transformer: Use deprecated,- VT preferred
RTU	-	Remote Terminal Unit
SCADA	-	Supervisory Control and Data Acquisition
VT	-	Voltage Transformer
VVO	-	Volt – Var Optimization

2 History of Distribution Automation

2.1 Substation-based Automation

The technology that preceded the present technology, known today as Distribution Automation (DA), was called Supervisory Control. Supervisory Control systems were used in substations and usually communicated to a manned Control Center(s) via leased telephone circuits. Due to their expense of installation, operation and maintenance these Supervisory Control systems were usually applied primarily in transmission substations and sometimes in distribution substations co-located with the transmission substation. The devices which were most commonly remotely monitored and controlled were feeder breakers. The breakers' RMS current magnitude was generally monitored from one phase, using a single CT from a breaker and voltage measurement acquired from a station voltage transformer (historically referred to as Potential Transformer). There would be a position state (open/closed) status for each breaker. In some of the earlier supervisory controlled stations there was also monitoring and control of the position state of the switched capacitor banks. Also included were some Load Tap Changers (LTC) on Power Transformers which could be placed in a manual operating state and the tap changer raised or lowered as needed to meet special operating conditions.

As discrete component electronics evolved and morphed into printed circuit boards which improved cost efficiencies automation technology became more prevalent in the distribution substations. The devices monitored and controlled were the feeder breakers, the switched capacitors and the LTC's.

In 1974, a joint project was embarked upon to explore the then limits of digital technology. It was named "Project PROBE" (Power Resource Optimization By Electronics [21]. A minicomputer (Varian V-72) was installed in the control house of the La Grange Park distribution substation. Since the Varian was designed for office temperatures, a framed box was built for it, complete with a residential room air conditioner. All of the AC analog inputs were sampled at 16 samples/cycle, and stored in the Varian's memory. Contact inputs were scanned for state changes at the same rate. The only information the application programs had of the outside world was the data that was already stored in memory. In the first phase of the project (PROBE 1 – 1974-1978), the digital application programs – inverse time and instantaneous overcurrent, reclosing, LTC voltage control – were operated in a "shadow" mode, in parallel with the installed electromechanical relays. Later, the digital time constants were set slightly shorter than the E/M relays, and direct control was tested. The PROBE project was connected to 32 analog and 112 status inputs from the La Grange Park Substation and provided 24 control outputs for closing and tripping of breakers and switches, and controlling transformer LTC.

During PROBE Phase 2 (1978-80), a Varian V-77 minicomputer was added. experimental RF and power line carrier based sensor/controllers were installed at switched capacitor banks, reclosers and motor operated sectionalizing switches on selected feeders. PROBE software was used to flatten a feeder's voltage profile – the first application of integrated volt/var control (IVVC). In the 1970's, there were a number of theoretical proposals on how to best calculate the voltage change when a capacitor bank was switched on or off. An application engineer on the project, made this profound observation: within the voltage control accuracy limits, the best prediction of the voltage change when a cap bank is switched (on or off) is the voltage change last time it was switched! No need to know the impedance to the source, nor keep an extensive log of past operations – just the Δ V – up or down the last time it was switched [22].

Later, during EPRI Project RP 1472-1 "Integrated Control and Protection for Distribution Substations and Systems" [24], prototype microprocessor based digital distribution protection modules (DPM) were developed and tested. Each DPM included six functions: instantaneous overcurrent protection, time overcurrent protection, automatic reclosing, breaker failure protection, synchronism check, and under-frequency protection and a man-machine interface.

2.2 History of Line Distribution Automation

Gradually the technology evolved to include remote monitoring and control of motor operated distribution gang switches, line reclosers, switched line capacitors and line regulators. There was also a need for devices to monitor the primary phase voltage and the primary current at these newly monitored devices. While the traditional primary VT and CT could perform the function there was a need for something less bulky and less costly. These became known as Current and Voltage sensors and in some cases looked much like distribution line post insulators. With the addition of these sensors at locations on feeders, more system data was available for a local logic block to perform device operations locally.

However the distribution system operating philosophy was still the same as that of the "Supervisory Control" systems until the late 1990's. It was in this later time frame that the state of the electronics being applied in the DA devices was such that there was the ability to have at each monitored device an on board logic block which was essentially a Programmable Logic Controller. With this added capability distribution engineers were able to create logic scenarios under which one or more devices could periodically evaluate its data and, if the logic deemed it necessary, could initiate open and close signals for its device and could transmit defined changes in status and analog points to the other devices for use by their logic cells.

In the early 2000's microprocessor based relays became available in pole mounted controls for distribution line reclosers. In some cases, these line devices were more sophisticated than the feeder relays being deployed in substations. They had sufficient processing power to perform protection and communications functions simultaneously. This presented challenges in coordinating the new technology with legacy relays.

These line microprocessor based relays have inputs for voltage and current line sensors, options for DC operation of the recloser, battery backup, multiple communication ports, and multiple communications protocols with the ability to send and receive SCADA communications without requiring an RTU.

With these microprocessor relay reclosers and the automation of line devices such as gang switches it became feasible to create a group of devices which could perform fault isolation and feeder reconfiguration tasks without Control Center intervention. These devices utilized the inputs from their associated voltage sensors, current sensors and position status to initiate actions for their respective locations and transmit their changes to other devices which would respond with actions appropriate for the changes which each received. Some of these groups included a feeder normally open switch among its group. Depending on the location of a fault on one of the feeders the group of controlled line devices could shift load from one feeder to the other feeder, which could be controlled by a different relay that could be in substation.

In the above scenario a portion of one feeder was automatically switched to an adjacent feeder and thereby a different substation source relay and sourcing line device relays. This could result in the portion of the circuit which was moved miscoordinating with upstream devices therefore that circuit section could trip undesirably or not trip when it should therefore causing undesired upstream device trips. While a utility may consider this condition as temporary and choose not to make any changes to existing protection settings, the capabilities of the more advanced automation systems will allow for the automatic changing of the source line device and source substation breaker relay settings to predefined values for the specific scenario.

As the capabilities of the line microprocessor based recloser relays improved, algorithms became available which allowed the relay behavior to be based on dynamic current ratings. Some three phase reclosers became available with the capability to operate as three single phase reclosers or as a hybrid such that it has single phase operation and three phase lockout. To improve reliability indices, the functionality to decide when to switch on a single phase basis instead of on all three phases was developed. For example, line microprocessor based recloser relays can be controlled to operate as single phase tripping for load below a predetermined value and three phase tripping when load is above that value.

2.3 Today's Distribution Automation Applications

DA has evolved to include a wide array of applications that include monitoring, control, reconfiguration, reporting, and evaluation:

- Remote monitoring
  - Typically use SCADA protocols such as DNP3 or metering protocols.
  - Fault detection at feeder devices (e.g., faulted circuit indicators - FCI).
  - Circuit measurements (e.g. voltage, steady-state/fault current, and/or real/reactive power from discrete CTs, VTs and/or FCIs for both overhead and underground circuits).
  - Load measurements (e.g. energy, voltage, current and/or real/reactive power from AMI billing or distributed generation meters).
- Remote monitoring with control
  - Typically use SCADA protocols such as DNP3.
  - Voltage and VAR control (e.g., power measurements and voltage or VAR regulation with line capacitor banks or line voltage regulators).
  - Generation control (e.g. power measurements and generation mode of distributed generation).
- Remote monitoring with circuit reconfiguration
  - Typically use SCADA protocols such as DNP3.
  - Equipment status (e.g., open or close of station or circuit switches).
  - Fault detection, isolation and restoration (e.g., fault detection, power measurements, and open or close with line reclosers or switchgear with fault interrupters).
- Reporting
  - Typically use file transfer protocols.
  - Power quality measurements (e.g. harmonic content from high-end meters or monitoring/control devices).
  - Disturbance recordings (e.g. fault signatures or oscillographics from high-end meters or monitoring/control devices).
- Evaluation
  - Configuration at the time of analysis.
  - Accurate fault location (e.g. based on analysis of fault currents, voltages and/or disturbance recordings).
  - Spare capacity for circuit reconfiguration (e.g. based on assumed equipment capabilities and historical power measurements).

Many of these applications can share functions, sensors, and especially communications with other DA applications. This integration, when properly planned, can reduce costs and improve benefits to the global DA system.

DA schemes come in many varieties and complexities that range from simple applications that use local, independent equipment to system-wide, centrally-controlled automation. Localized schemes that use some form of intelligence can be connected to large control centers which can also be connected to even larger central control centers. DA schemes, such as Fault Location, Isolation, and Service Restoration (FLISR) or Optimal Network Reconfiguration, that reconfigure or change the distribution circuit can affect protective relaying. These schemes can also impact the fault level contribution and direction, particularly for systems operating in loop mode (section 3.1.3) or have distributed resources (section 3.6.7).

2.3.1 Local Intelligence

Localized DA schemes are applications where automatic functions occur with minimal communication between devices. Functionality is contained within the device and occurs based on external conditions, such as voltage, current, and position status. For example, Figure 2.1 shows a simple transfer scheme of Breaker T in which Loads X and Y are maintained in the event of the loss of either Line A or B. Assume a Line A fault that causes Breaker 1 to open. The Breaker 1 auxiliary contact is an input to the Breaker T control scheme and initiates a closure of Breaker T. After Breaker 1 is restored, Breaker T automatically opens. The Breaker T controls may contain transfer or restoration time delays. In some schemes, loss of voltage initiates breaker operation instead of auxiliary contact logic.

However, now assume that Line B cannot supply the combined X and Y loads. This low-intelligence scheme is limited in that the breakers will simply trip and close based on breaker position, thus resulting in stress to the system, overloads, and additional outages. A more intelligent scheme is therefore desired.

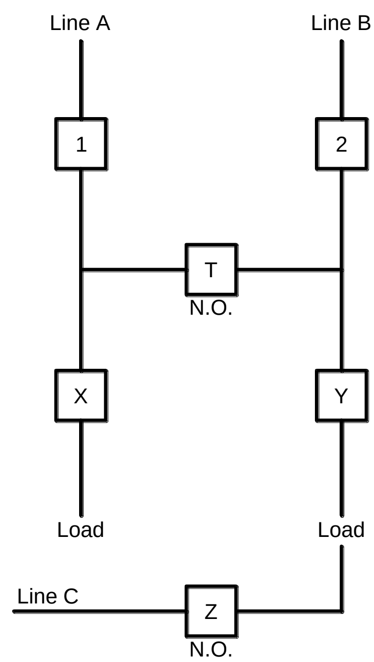

Figure 2.1 – Simple Distribution Transfer Scheme

2.3.2 Distributed Intelligence

Distributed intelligence, also referred to as decentralized intelligence, applies communication and software to localized sectionalizing and fault-interrupting devices to provide automated control within a defined area that can vary from a simple circuit segment to a region where multiple circuits interconnect several substations. While these devices are primarily controlled at the installed location, rather than from a central location, the shared software and communication distribute the data pertaining to the event or condition among the devices to effect the required circuit reconfigurations.

The distributed intelligence software utilizes various data inputs from communicating devices, including substation breakers and line devices to make switching decisions in order to reconfigure the system. Inputs include, but are not limited to, open/close status points, current, and voltage values. Automatic switching can be performed to promptly restore portions of circuits following outages or optimize feeder or substation transformer loading.

The responses to system conditions are prioritized based on the time required to make decisions and issue switching commands. These systems can typically evaluate the load to transfer, and select the proper transfer to perform, and thus avoid overloads in the substation and on the feeders. The system operator is advised of any automatic transfer if there is SCADA functionality to these DA devices. This monitoring of the automatic operation is often communicated separately from the distributed intelligence functions.

While distributed intelligence bears a resemblance to communications assisted protection schemes, such as directional comparison blocking (DCB), permissive trip, and transfer trip, it is necessary to make a distinction. While these schemes can span a considerable distance and involve multiple protection relays, they only have the ability to affect the circuit which they protect and cannot reconfigure a wider area after the protection action, and should not be considered as DA. However, it is necessary to account for the behavior of these protection schemes if they fall within an area with DA.

Assume that intelligent communication is added to the breaker control schemes shown in Figure 2.1 that includes load X and Y information. For the scenario where a Line A fault locks out Breaker 1 and Line B cannot support the combined X and Y loads, intelligent communications can now provide automatic actions to maintain the loads. Breakers X and Y can communicate to Breakers 2 and Z that the load is too high for Line B alone. Breaker T can close to pick up Load X, while Breaker Y trips and Breaker Z closes to pick up Load Y. All communication and control is contained locally.

However, now assume that another similar load center is located on the end of Line C, outside the area covered by this DA scheme. Also assume that Line C is heavily loaded due to some configuration at the remote end and that Line C cannot feed Load Y. A more intelligent scheme is therefore desired that provides communication among the distributed schemes.

2.3.3 Central Intelligence

DA schemes utilizing central intelligence take the concepts associated with localized or distributed intelligence schemes and apply them across larger control areas. A centralized intelligence scheme can determine the optimal switching sequences, and if desired, issue the switching commands to optimize FLISR and other advanced functionality, including Optimal Network Configuration, Volt-VAR Optimization (VVO), and Dynamic Equipment Rating (DER). Since the central intelligence scheme has the capability to reconfigure large sections of the system, various possible system conditions must be analyzed in advance, and logic must be designed into the central controller in order to allow it to make decisions and issue switching commands as system conditions require. This centralized intelligence usually resides at a remote location, such as a Control Center or area office, and can be integrated with the SCADA system.

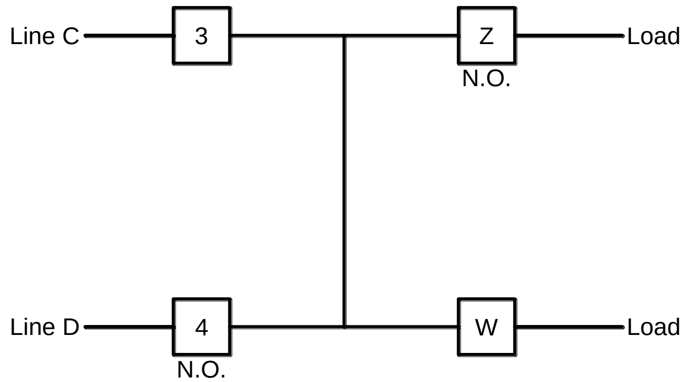

Figure 2.2 – Simple Distribution Transfer Scheme Expanded

Figure 2.2 shows the remote end of Line C. In the situation where Line C would be overloaded by feeding both Load Z and Load W, the centralized intelligence scheme can close Breaker 4 and use voltage, current, and system configuration data from the entire system to reconfigure other parts of the system to ensure that Lines C and D have sufficient capacity for the additional load.

2.4 Telecommunication Requirements

DA depends on reliable, robust, and secure telecommunication systems. They also must be designed and implemented in an understandable way to ensure any required trouble-shooting is straightforward. They must be designed in such a way that a failure of communications does not cause a failure in basic protection. Since a good telecommunications system is the cornerstone of DA, potential workforce jurisdictional problems (internal or external) need to be considered, during planning, implementation, and on-going operation.

3 Effects on Relay Applications and Settings

3.1 Circuit Reconfiguration

Circuit reconfiguration is the modification of the topology of a distribution network by operating NC (Normally Closed) and NO (Normally Open) switches or circuit reclosers. Switches located along the feeders are NC and allow isolating sections of the feeder when required. These are also called Sectionalizing Switches. Switches connected between two feeders are NO and allow transferring loads between the feeders when they are closed. These are also called Tie Switches.

Distribution circuits can be reconfigured, proactively or automatically:

- Proactive circuit reconfiguration – This is typically done to prepare circuits for either a permanent or a temporary change to the distribution system in order to improve the operating condition of the system. Factors to be considered include the improvement of voltage profile, energy loss reduction, maintenance or repair of circuit components, or to relieve a temporary overloading on the transmission or distribution system. The reconfiguration can also be either manual, by supervisory control or by automation. In all cases, it is expected that protective relaying for the affected circuits has been assessed and changed as necessary for the new circuit reconfigurations.

- Automatic circuit reconfiguration - This is typically done to react to a system condition such as for FLISR that requires remote or local automatic control, and some intelligence to analyze the fault situation and to decide alternate configurations to restore service to the maximum number of customers. This automatic reconfiguration may require new protection settings that can be pre-programmed as alternate setting group(s), and may also require protection equipment to support reversal in the direction of current and power flow from the normal direction.

Depending on the cause, the circuit can remain in a reconfigured state for minutes to days and in some cases, permanently. Consequently, the protection engineer is challenged with determining whether protection settings can be applied that will accommodate all possible circuit topologies resulting from automated and/or SCADA switching, or whether it's more prudent to accept the consequences of reduced coordination margins when segments are added to the normal topology of a circuit (e.g., the total load of the new topology encroaches or exceeds the expected protection overload setting). This perspective is more readily appreciated when the addition of healthy segments is due to a permanently faulted segment on the adjacent circuit, as the likelihood of a second fault occurring on an added segment may be considered improbable. Additionally, the variability of circuit reconfigurations during emergency conditions can be so numerous that acceptable coordination may not be achievable and/or sensitivity may have to be relaxed.

When the protection technology present in the fault-interrupting components permits, certain automation and/or SCADA solutions could enable the application of alternate protection settings that better accommodate the reconfigured circuit. However, as more users focus on optimizing the efficiency of power delivery, the normal topology of medium-voltage circuits may vary based on economic dispatching strategies. Therefore, the protection engineers will increasingly be challenged to provide protection concepts that automatically adapts to the reconfigured state of the circuit.

Some protective relay considerations are:

- Automatic fault detection and restoration schemes must be coordinated with automatic reclosing to allow protection devices to attempt to clear temporary faults and restore service with auto reclose.
- An additional reclose shot may be needed after DA has reconfigured.
- Distribution circuit relays must be able to "see" all faults after all or part of an adjacent circuit has been transferred to that circuit and may need to revise the setting as part of circuit reconfiguration.
- DA scheme must be able to distinguish between faults (the DA system must operate for these) and non-fault tripping (load shedding, underfrequency operation, manual tripping). Utilities rely on protective relays for that information.

Implementing an automatic reconfiguration system is a major change to the conventional operation of the system where human judgment and decision are involved. This change has to be managed to assure the workers that the system is safe. A general way to proceed is to implement the automatic reconfiguration gradually to reach a point where all the analysis is done automatically and the new configuration is proposed to the operator for final approval. After a while, if the system is well designed, the operators will see that the system is safe and does not need human decision anymore.

Another safety issue is to disable DA automatic circuit reconfiguration during hot line work (similar to reclosing).

3.1.1 Load Sectionalizing Device Locations

Improving the ability to manage load through circuit reconfiguration requires placing of the sectionalizing devices so load can be fed from two or more sources. Remote control switches, breakers, reclosers, or sectionalizers could be used as a switching device. The feeders are sectionalized considering service flexibility, service reliability, and load priority among other parameters.

The ability to transfer loads among neighboring feeders is accomplished by installing tie switches between them. Given there are a limited number of possible tie switch locations between circuits, evaluation must be made to determine the optimal location. Typical candidate locations for these NO tie switches are often the double deadends where the feeders meet.

Any switch location has to be validated with reliability analysis, as well as economic considerations (revenue, installation cost, maintainance, etc.). Load flow analysis is also recommended to adequately evaluate that the parameters like voltage profile, power factor, total losses, etc., are within specified ranges for different configurations. The guidance for these studies is beyond the scope of this document.

Figure 3.1 illustrates the flexibility offered by several double deadends and illustrates the advantage associated with placing a tie switch at the different locations of existing double deadends. Those located in the first section of the feeders, such as number 5, do not offer the possibility of partial load transfers through the operation of the NC switch, but only allow a full load transfer. However, this option would require removing the source at either SUB A or SUB B to keep the feeder radial.

The double deadends located in the second section of the feeder, such as number 6, offer the possibility of transferring only two thirds of load to keep the feeder radial.

The double deadends located in the last section of the feeders, such as number 7, allow the transfer of one or two thirds of the feeder load. Therefore the switch located at number 7 has more flexibility than the switch located at number 8 to carry out transfers.

Although a switch in the last section provides the most flexibility, other considerations must be made. Among these considerations is that, generally, the closer to the substation, the better the voltage profile for load transfer. With this in mind, it is clear that a NO switch installed at the last section but closer to the substations, offers better conditions to receive the load of neighbor feeders, considering losses and voltage levels.

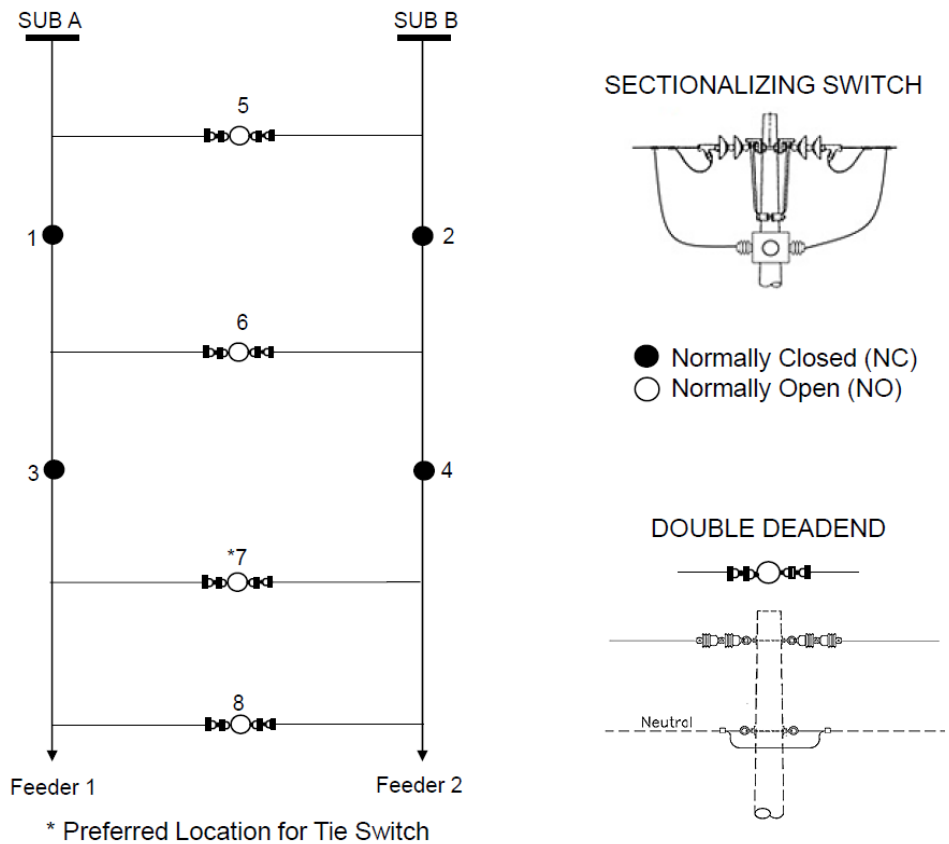

Figure 3.1 - Flexibility offered by NO and NC sectionalizing switches

For dense urban areas where underground primary systems are more prominent, the same sectionalizing capability can be obtained by using padmount or submersible switchgear that have multiple feeder positions and load positions. Figure 3.2 illustrates an underground loop configuration where feeders are loaded to 75% of maximum capacity and sectionalized into thirds.

Since these padmount switchgear have more than two feeder positions, they can also be used in place of multiple overhead switches where there is a three way or four way intersection (e.g., providing the functionality of switches 1 and 3 and a switch in position 6 in Figure 3.1, if all these switches were in the same proximity).

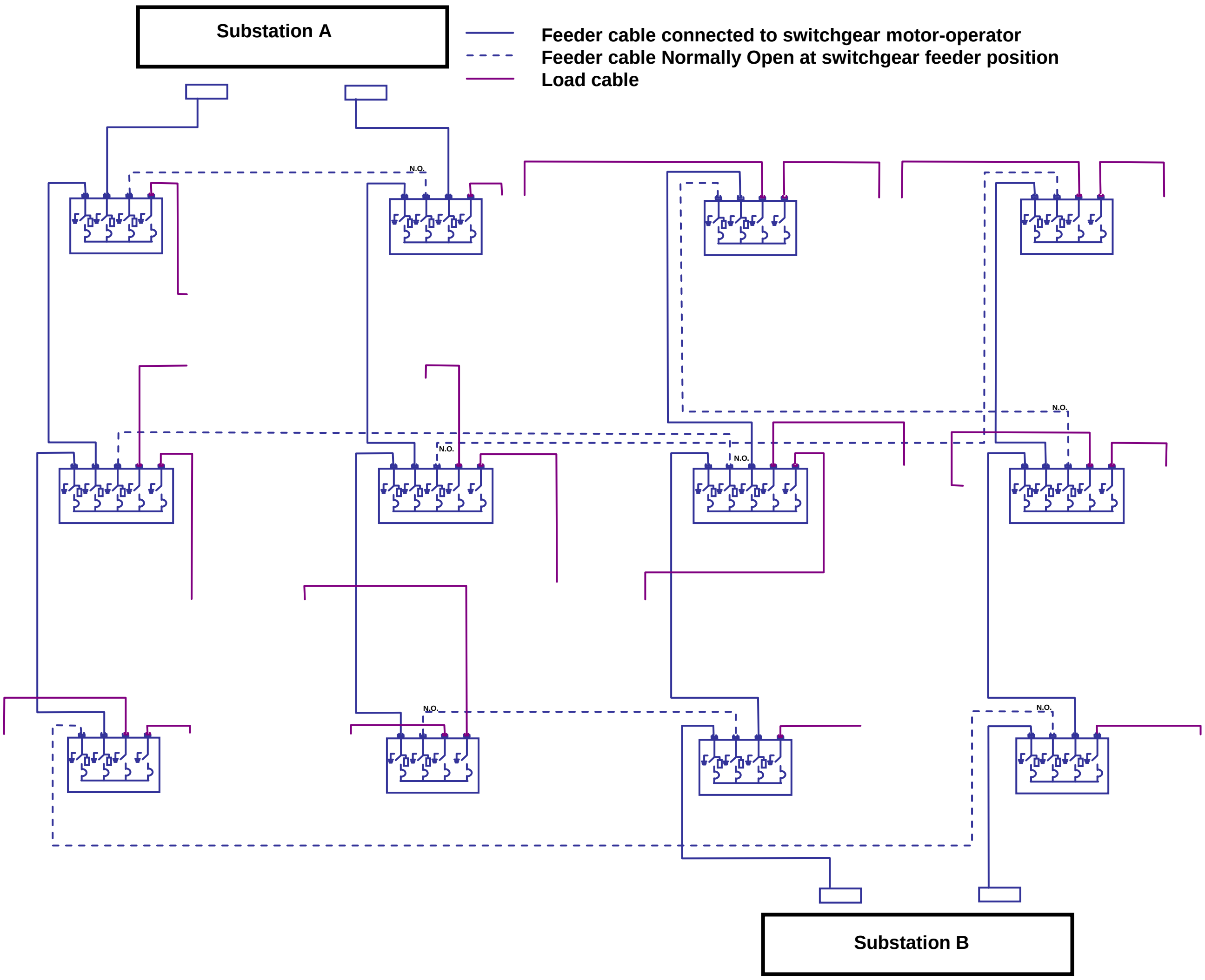

Figure 3.2 – Primary Underground Open Loop Example

3.1.2 Load Serving Issues

There are many load serving issues that protective devices need to deal with during or after circuit reconfiguration:

- Close-transition switching (i.e. temporary parallel sources, non radial feeders)
- Increase/Decrease in load from cuts and ties of taps without transferring any protective devices
- Reversal in power-flow and transferring of protective devices in a loop-system
- Network (multiple active sources) reconfiguration

3.1.3 Looping

The reconfiguration procedure proposed before, forces the system to operate in a loop mode since the feeders get connected while the tie switch is closed and before any link switch is opened. During this condition, the system is subjected to two undesired effects:

- The short circuit levels throughout the new established loop rises which could risk the withstand capabilities of the equipment connected to it.
- The coordination of the relays and other protective equipment associated to the feeders could be upset mainly because the relays are non directional.

Despite these effects, the situation may be acceptable and worth consideration, provided all the equipment installed is rated for the most severe short circuit condition. In addition, the operator needs to be aware that should a fault occur during the switching process, more than one feeder may trip simultaneously. This illustrates why the switching is recommended to be completed as quickly as possible.

3.1.4 Fault Location, Isolation and Service Restoration (FLISR)

One of the most important functions in DA is the service restoration in the event of a fault of a primary feeder. The main goal of automatic service restoration is the operation of the tie switches to restore the energy supply to the maximum number of possible areas having been affected by the fault. The problem has a combinatorial nature since it deals with the on/off status of the switches.

When a fault occurs, the protection devices detect it and open the corresponding isolating devices; simultaneously the fault has to be located by means of device controls, faulted circuit indicators, disturbance analyzer or information coming from the supervision system (SCADA). Once the fault is located, the corresponding area is isolated by means of the opening of the sectionalizing switches nearest to the faulted segment.

The load sections located between the substation and the sectionalizing switch upstream of the faulted area are energized again from the main switch. If the fault is in the substation or in the first feeder section, the whole feeder will be without service.

The sections that are without service and are not faulted may be restored to service by closing the appropriate tie switches, provided that the backup feeders are not overloaded after executing the transfer.

The steps mentioned above should be completed in minimal time for the unfaulted feeder segments to avoid impacting the Quality Service Indices. The outage time of the faulted section will depend on the severity of the fault and the service crew performance.

The overall process of FLISR can be summarized as follows:

1) When a fault is detected, the corresponding protection operates and trips one or more isolating devices.
2) The fault is located and associated sectionalizing switches open to isolate it. (Switch operations can occur either during the breaker reclosing sequence or after lockout.)
3) The feeder is re-energized up to the first sectionalizing switch upstream of the fault. (Upstream restoration)

4) The healthy sections are transferred to one or more neighboring feeders by closing NO switches. (Downstream restoration)
5) The faulted section is repaired by the service crew and the switches are restored to normal.

There are a finite number of re-configurations possible based upon the number of available switches and their locations. The complexity of these solutions and the desired outcome is beyond the scope of this document

When carrying out the restoration, the operations that are executed should guarantee that the system satisfies certain conditions, such as:

- Transformer and line currents remain within specified limits.
- The voltage drop stays inside an established margin.
- Radiality of the system is maintained.
- Reduce number of equipment operations as much as possible. Critical customers are given priority
- System balance is maintained as much as possible.
- The coordination of the protection is maintained.
- The system protective relaying (and fusing) must maintain the ability to detect and clear faults for all reconfigurations.
- The harmonic content and the power factor is conserved inside the limits established by the respective system and in particular should follow the guides of the IEEE Std 519-1992.

To illustrate a complete process, the system shown in figure 3.3 is used, where a fault occurs at location Z2.

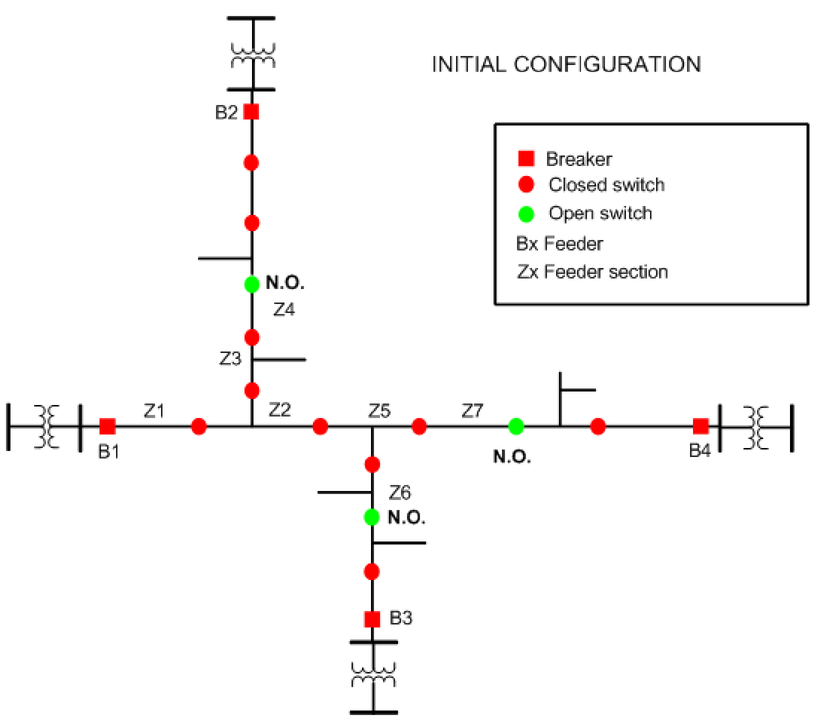

Figure 3.3 – FLISR Example

F1's load beyond the Z2 line section tie switch should transfer to the unfaulted sections of neighboring feeders provided that they have the capacity. Thus the fault has to be isolated by means of opening the NC switches, and then the NO switches can be closed to restore as much of the system as possible.

The solution should be a configuration that fulfills the operating restrictions specified previously and reestablishes the service to the greatest number of customers.

Figure 3.4 shows a possible configuration of the system that reestablishes service to the sections of the feeder after being presented a fault in section Z2 and it also satisfies the radial condition.

Section Z1 continues being fed by F1, Z3 and Z4 are now fed by F2, Z5 and Z6 are received by F3 and Z7 is fed by F4.

The implementation of the automatic FLISR is achieved by means of Centralized Intelligence or Distributed Intelligence. In the former, appropriate software packages along with a SCADA system require control and information of the overall system. In the latter, peer to peer communication between devices arranged in groups or teams can have the intelligence to determine the configuration actions to follow.

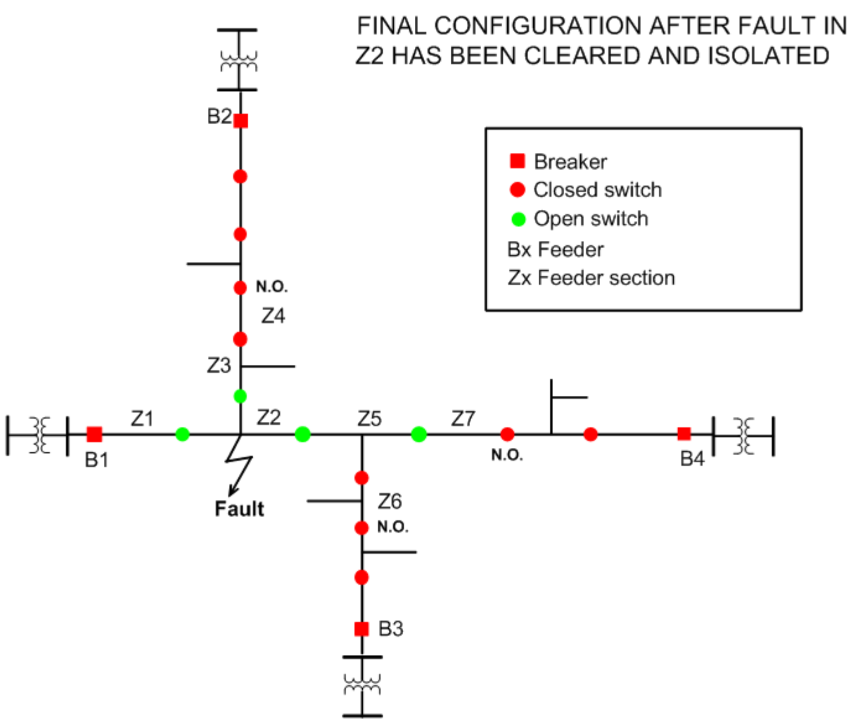

Figure 3.4 – FLISR Reconfiguration

In either case, the coordination between protection devices have to be maintained as mentioned before. To achieve this, it is often required to take advantage of the configurable groups and functions that new protective technology offers, to meet the needs of the application. In particular it is very important to ensure that the new current levels of the feeders that receive load from faulty neighboring feeders do not encroach on the pickup values of their corresponding protection elements under maximum loading conditions. Also the fault currents available on transferred sections may be lowered and the system protective relaying (and fusing) should maintain the ability to detect and clear faults in the associated zone of protection.

3.2 Impact on Various Protection Schemes

There are different issues and ways to accommodate various protection schemes that may have other impacting factors.

3.2.1 Overcurrent Protection using Multiple Setting Groups

Most microprocessor relays have multiple setting groups available. Thus should a distribution line section be reallocated by DA, it may require a different setting group be used. The more obvious location for a settings change would be on the distribution feeder protection but it could be a transmission line relay that would need to be adjusted. For example, the transmission line auto reclosing (i.e. the timing or the need for dead line sensing) could be reset if DA has moved a large motor load that would be a backfeed source to a different line. Thus, a transmission line that used dead line sensing with a 15 second delay due to a motor backfeed might be changed to no voltage sensing and only a 1 second delay.

3.2. 2 Overcurrent Protection using Adaptive Relaying

The use of adaptive relaying may be available with some relays and the use of DA could make a difficult setting calculation even worse. For example, if the phase TOC (Time Over Current) pickup setting is adjusting on the fly based on line loading, the use of DA could change the line loading fast enough that the adaptive setting might not react quickly enough. Adaptive settings often employ a timing or rate of change setting; a setting that could be violated due to DA and thus lead to a line tripping in error. Assume an adaptive setting is set at 110% of the load current up to some maximum level; should DA close in another line, then the line loading could suddenly jump to greater than what is was just a few seconds or minutes prior. Thus the relay could trip in error on load so anticipated load variations should be considered before utilitizing an adaptive relaying scheme.

3.3 Zone of Protection

In automation schemes, the zones of protection can change as feeder configurations or sources change. If feeders are set for certain reaches, overcurrent time delays, etc., then changing the feeders can result in the loss of coordination and /or relaxed sensitivity. This change could be as subtle as using a new type of recloser on existing feeders. Impacts due to changes in available fault current, changes in current flow direction, and changes to fuse coordination should be considered.

Typical distribution line reclosers have been either three phase operating/ three phase lock out devices or single phase operating/ single phase lock out devices. If a single phase fault occurred within the zone of protection of a three phase line recloser, all three phases would lock open and would interrupt all customers protected by that recloser.

Recently, technology has permitted the utilization of line reclosers capable of operating as either three single phase reclosers, a three phase recloser, or a single phase recloser with three phase lockout. With communications and automatic schemes these devices offer opportunities for increasing the level of service reliability for a feeder, particularly on a per phase basis. However, they also pose challenges to coordination. For example, if the automation scheme employs single phase clearing, the upstream ground relay settings could be exceeded thereby causing outages to a much larger number of customers than originally anticipated.

3.4 Overcurrent Adaptive Relaying

The evolution of DA has changed the manner in which circuits are operated and configured. Automatic circuit reconfiguration can quickly change the whole structure of the circuit. Fast reconfiguration of circuits can now occur which in the past would have overwhelmed the ability of protective relay schemes to adapt to new circuit characteristics.

Circuit reconfiguration can occur automatically through DA or by manual switching. The reasons for circuit reconfiguration can vary based upon the system need. These could include the need for load transfer, load recovery from a fault, or maintenance. Reconfigured lines bring about changes in load current, available fault currents, and voltage drop. The new circuit configuration may alter protective device coordination and the load of the new circuit configuration may also exceed the existing trip settings of the protective devices.

Microprocessor based relays that are now prevalent in recloser controls have allowed Adaptive Relaying to play a more prominent role in system protection. Adaptive Relaying allows the protective device to alter its settings based upon changing circuit load patterns and conditions. Adaptive Relaying infers that the settings changes can occur automatically, or “on-line”. The settings profiles can also be changed remotely via SCADA communications or locally at the relay.

Take an example where the utility has two adjoining circuits. The two circuits may or may not originate from the same substation source. Tie switch locations between the two circuits allow the flexibility to transfer load between the circuits. If one circuit suffers a fault, the healthy portion of that circuit can be transferred to the adjacent unfaulted circuit. In this case, the new “appended” circuit characteristic has changed. Protective devices which have Adaptive Relaying have the capability to react quickly to these changes.

The substation feeder breaker (or recloser) with the appended load may see encroachment upon its overcurrent settings. What has been proven in the field is the ability of the adaptive relay’s programmed algorithm to detect and identify the increased load current that is encroaching upon the overcurrent trip setting. The adaptive relay can automatically increase the trip settings to account for the new load. If necessary, the algorithm can call for a change in the TCC curve. These changes can also occur for the ground settings, as well as other required parameters. Fault sensitivity must be maintained under various operating conditions.

Along with adaptive settings which occur at the substation level, the line reclosers on the distribution circuit can also detect the circuit changes and adapt their settings. Line reclosers may encounter increased load or a change in current direction. Adaptive settings help ensure the line recloser will remain coordinated with the new source.

There has also been success in the field to create algorithms to change the line recloser configuration from a "three-phase trip and three phase lockout" device to a "single-phase trip and single or three phase lockout" device. The "single-phase trip and single phase lockout" mode is programmed for lighter load conditions where current imbalance will not unduly affect the substation feeder ground fault protection. Just as in the substation feeder breaker example, the line recloser settings profile can change automatically, remotely by SCADA, or locally at the relay.

The premise of Adaptive Relaying assumes that the new circuit configuration has adequate capacity to accept the increased load. It is also assumed that in the same way the relay accepts increased load, it will also automatically adjust its settings back to normal when the circuits are restored.

Another important factor to consider when transferring loads between circuits is cold load pickup. If an outage occurs and the recovery switching is delayed, cold load pickup becomes a factor. Earlier electromechanical devices had limited capability for cold load pickup changes. However, newer adaptive relays have a greater range of selection for pickup, timing, and TCC curve values.

For planning purposes, the utility should stay up-to-date with system studies and protective device coordination. Protective device upgrades may be necessary to maintain reasonable coordination. The use of voltage regulators and capacitor banks and their affect on circuit voltage must also be taken into consideration. The use of overcurrent adaptive relaying will not create a perfect world but it will allow vastly improved circuit restoration and switching that was not possible in the previous generation of relays.

3.5 Overcurrent Protection Coordination

For DA schemes, like feeder reconfiguration, the settings on downstream devices (fuses, vacuum fault interrupters, line reclosers) may require relay changes to the upstream devices in order to maintain coordination in the reconfigured state. A coordination study for each possible re-configured state is accomplished by using the same techniques applied to radial distribution lines:

- Raising the instantaneous tripping value, so that it will not pick up for faults at or beyond a downstream device(s). This action can include providing a definite time delay or disabling the instantaneous element.
- Raising or lowering the pickup value of time-delayed tripping elements to coordinate with the downstream device(s).

Alternate setting groups can be used to provide "new" settings in each of the re-configured states. However, the resulting multiple sets of relay settings require improved documentation of setting calculations in order to maintain device coordination and communication between Planning, Operations and System Protection.

3.6 Protection Functional Requirements after Circuit Reconfiguration

3.6.1 Fuse Saving/ Sacrificing

Two basic operating philosophies are used for distribution system fuse coordination: fuse saving or fuse sacrificing. The fuse saving design allows upstream protective devices, such as reclosers, to operate for temporary faults a select number of times before the downstream fuse opens. This approach minimizes the number of customers impacted by extended outages, but interrupts more customers in the process. The fuse sacrificing design, which is also known as fuse blowing, clears downstream faults without operation of upstream protective devices. The result is the avoidance of one or more momentary outages to a large number of customers for an otherwise temporary fault. However, this design philosophy is at the expense of an extended outage to a smaller number of customers. Combinations of both designs can be used, depending on specific feeder requirements, and utility setting and operating practices. For example, a feeder with a critical load may need a fuse sacrificing scheme, while residential loads may be better served by fuse saving. Several factors influence the overall decision of which design philosophy is better utilized, but is outside the scope of this report.

DA can affect either design and the utility will need to perform a study to determine the possible effects. The utility will also need to determine if any additional changes are required, including additional automatic, or adaptive capability. For example, "remote controlled fuse saving" enables low instantaneous settings on reclosers for fuse saving for temporary faults during storms and windy conditions (when many temporary faults occur) and converts back to fuse blowing on fair weather days. As well, if the operation of an automation scheme results in feeder reconfiguration such as bypassing a line recloser, then the fuse saving scheme might be lost while in the new state. Conversely, if a feeder with a critical load is automatically connected to a different source that employs fuse sacrificing, the overall setting philosophy for the critical load may be compromised.

3.6.2 Fault Locating

Microprocessor based relays can accurately determine fault location if the line conductor is homogeneous, otherwise fault location is calculated using recorded fault data and the available short circuit software.

On distribution systems, unlike transmission systems, a single-ended algorithm for fault location may not always yield accurate distance to fault results to positively identify a faulted section. Some of the factors that hinder the effectiveness of a single-ended algorithm include:

- Tree branch design of the circuit creates multiple locations with equal impedance from the substation.
- Distribution circuits carry single-phase, double-phase, and three-phase laterals off of a main three phase primary distribution circuit.
- Distribution circuit geometry and conductors are typically not homogeneous.
- Distribution circuit customer load density is variable along the feeder.
- Distributed generation may exist on the distribution circuit.
- Distribution circuit configuration may vary due to various switching conditions

On the distribution systems, DA can be utilized to quickly identify and isolate the faulted section (not the precise fault location), and restore power to customers which are connected to the unfaulted sections of the circuit. Fault location information from microprocessor relays, short circuit event information recorded by RTUs, sectionalizer status, recloser status, other system element status, combined with system modeling and GIS information may be used in DA systems as input for faulted section identification means. Adequate protection and coordination between protective devices must be ensured for any switching action by DA.

In addition to radial distribution systems, some utilities use secondary spot and grid network systems in congested areas to provide highly reliable service. The network transformers are often protected by the circuit breaker at the substation and for a transformer fault, the entire primary circuit is de-energized. A network protector is installed at the low side of the network transformer which is equipped with a reverse power relay that will open if current flows into the transformer from the low side. Any communication interface that is used to automatically control these network systems can be utilized to quickly identify a faulted section in a network system.

3.6.3 Remote or Alternate Settings

One of the principal applications of DA is the remote controlling of feeder protection relays and reclosers. Modern reclosers and substation protective relays can have their settings changed by remote control. However there could be a reluctance to use this function because protection settings are sometimes linked with the distribution system safety (i.e., hold-off, hot line, non-reclosing function).

Most of the controllers also have the capability to use several alternate settings, allowing the protection device to be efficient in various conditions, for example when the system configuration is changed. This flexibility has to be managed to avoid protection issues (i.e. wrong setting group selections may lead to reliability issues or lack of fault coverage).

As it was indicated in Section 3.4 circuit reconfiguration can occur automatically through DA or by manual switching. Adaptive protection aims to adjust settings of protective relaying to the prevailing conditions of a power system. This can be achieved readily with the multiple group settings available with microprocessor relays.

For each scenario, a coordination study should be performed and if the results impact the relay settings, a new group should be assigned to the scenario. Inputs for each condition should be received in the relay for the change to be implemented. Typically the change of position of a breaker could indicate the need for change in the setting group.

3.6.4 Precautions

Education of electrical workers and reliable local and remote indication and control are the keys to making employees knowledgeable about the consequences of DA. Automated devices must be clearly identified on maps and schematics, since they are exceptions to the usual utility practices.

If utilities allow personnel to work on energized feeders, a "hold tag" (also referred to as a hot tag, a one-shot, or a hold-off) is issued, whereby all automatic reclosing is disabled. If the upstream device operates, the power operations dispatcher does not attempt to close the device back in until the person holding the tag is contacted. With DA, the upstream device might be on the feeder rather than back at the substation, so Dispatching must take extra precautions.

For clearances, lock-out and tag-out procedures must consider automatic switches and line reclosers.

There is an increased risk to the public if DA devices are not built to keep non-utility personnel from getting access to the control cabinets and other associated equipment.

At work locations where the arc flash or blast hazard exceeds acceptable levels for workers with appropriate clothing (i.e. energized line work or confined space work), coordination is sometimes temporarily sacrificed by enabling the high/mid set instantaneous to mitigate the impact of arc flash/blast.

3.6.5 Voltage

The pre-fault voltage level has a direct correlation to the available fault current during a fault condition. For example, if the voltage is 5% higher (126 volts, secondary) than nominal (120 volts, secondary), then the fault current level will also be 5% higher than the fault current level calculated at nominal voltage. A similar correlation can be shown for lower voltage levels, producing lower fault current levels. The impact on the calculated fault current needs to be considered for the entire range of voltage the protective device is expected to experience.

Voltage and phase angle differences at switching points need to be considered during close transition switching. The addition of voltage transformers on each side of the switch can provide the ability to sync check before making this transition. Reverse power flow may require consideration of voltage regulator controls.

3.6.6 Capacitors

Due to the increased availability of communications equipment, many utilities are employing capacitor control systems. These systems use a centralized computer to monitor the MW and MVAr flows, and then open and close capacitors on the distribution system to maximize efficiency of power flow. If these systems do not account for the circuit reconfiguration, they will be unable to properly monitor and control the power flow. The addition of shut capacitors to the reconfigured circuit can impact relaying and may warrant the use of alternate settings.

3.6.7 Distributed Resources

Historically, DA was thought to be mostly for radial distribution circuits and perhaps for some two terminal circuits. During certain operating conditions, the availability of a method to do switching and adjusting of the loading through the use of DA can improve the system operation. Things become somewhat more complicated when Distributed Resources (DR) are also on the distribution circuit.

These DR are typically operated in parallel with the distribution system and are equipped with intertie protection to provide for separation from the distribution system for a disturbance or outage of the distribution circuit. IEEE1547-2003 ”Standard for Interconnecting Distributed Resources with Electric Power Systems” provides a uniform standard for interconnection of distributed resources with electric power systems, including standard requirements that shall be met at the point of common coupling (PCC). Today, there is an evolving family of 1547 standards defining testing requirements to meet 1547-2003, and for providing guidance on each portion of the 1547-2003 standard. One of these is 1547.3 IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems. This guide provides insight into monitoring, information exchange, and control—such as “transfer trip” for certain islanding conditions. (for additional detail go to: http://grouper.ieee.org/groups/scc21/).

Protective relay settings have to be designed for the circuits where reverse power or fault current flow is possible. The complexity can increase if voltage regulators and/or reclosers are on the system but some of today's systems can handle this complexity.

Several factors come into play; not all of them strictly relay protection oriented. Some of the issues are: changes to the settings or timing and fault current contribution affecting overcurrent coordination.

3.6.7.1 Load (line) Reconfiguration

One of the main reasons for using DA is to have the ability to reconfigure the line and thus change the loading patterns during certain system conditions. In order to do this, switching devices are placed in strategic locations on the line. But one of the underlying premises might be that the lines involved were all from the same substation or another substation very close by such that there is no real concern about the phase angle difference across the open contacts. Should there be a DR on any portion of a line, there could potentially be an unfavorable phase angle difference. Thus there could be the need that potential transformers and synchronized closing be installed at these various locations, which means that a simple disconnect switch might need to be replaced with a power circuit recloser, circuit switcher, or even a circuit breaker. Obviously there will be a cost involved for that installation.

Another thing to be considered is whether the DR will need to have a stability study completed. It could be possible that under certain reconfigurations, should there be a fault; a DR generator could go unstable. Oftentimes a stability study is not performed for distribution lines but when DA is involved this type of study may be warranted.

During the design stages of the DA for line configuration, if a new DR is to be installed, then the physical location of the DR site could be reviewed to see if there are opportunities for improved reliability and efficiency. Reference [18] mentions that exhaustive searches and/or optimization methods may need to be applied to determine the reliability and efficiency. Reference [19] also indicates that the time-varying loading needs to be taken into account and that using just the peak loading conditions will generally not give the best results. Obviously for existing DR locations, there would probably not be an easy way to reroute the line. If there is a DR to be installed and if there is some leeway in the physical location, then anything to aid the DA system might be considered.

3.6.7.2 DR Relay Protection

Typically, DR locations should have some sort of relay protection for faults. However, if DA is installed, then the existing protection at the DR may need to be replaced. Communication from the substation DA equipment to the DR may be needed to insure that the DR is using the proper settings for the current system configuration. In other words, the DA system may have to indicate a setting group change to the DR based on how the lines have been reconfigured.

As previously mentioned, the type of protection at the DR may need to be replaced. For example, the old scheme might have just used under/over-voltage, under/over-frequency, and perhaps a few overcurrent relays. But with the DA system installed, impedance or even current differential protection might have to be used.

Also, reconfigurations of a DR from one line to another line impacts relay protection schemes on both lines. The first extreme example would be when a DR exists on the end of a long tap and is switched to a short line. The line relays may be set too short to protect the tap. The second extreme example is when a DR is on the end of a short tap and switched into a long line. The line relays may now overreach the DR terminal. In both cases, the DR is a source into a different line which can then impact protection of other lines. Reconfigurations of DR into different lines are further complicated if the lines contain pilot schemes as not only protection settings are affected, but also communication systems.

3.6.7.3 DA Relay Protection

Depending on what line a DR has been reconfigured to, the feeder protection may need to be adjusted via a setting group change to optimize the setting. For example, an impedance relay may need to be changed because the apparent impedance was different due the generator influence. Another example could be the ground fault relay of a line may need to be changed because of the DR zero sequence influence.

3.6.7.4 DR Control by the DA System

If a phase angle adjustment is needed, then the DA system may have to control the DR generator. Likewise, the DA system may have to also control the DR power output as well as the voltage and frequency.

The DA system will most certainly need telemetry from the DR to know if switching or a line reconfiguration can be safely accomplished. The real-time connection of larger pre-existing DR systems may already be under the control of the utility but the very small ones may not be. Thus a communication medium and its associated equipment may need to be installed to even the smallest of DR sites from the DA system.

4 Impact of Distribution Automation on System Maintenance

An automation system is an important part of a utility's efforts to maintain the power system and provide reliable service to its many varieties of customers. When properly designed, the automation system saves time and money by eliminating the regular need to visit each remotely controlled location to inspect, gather data, perform adjustments, and review actions taken by the microprocessor relay.

The benefits of incorporating an automation system into a utility transmission or distribution structure are well documented. One item that is not always reviewed as part of the long term operating use of the automation system is the plan for routine maintenance on the hardware and software that make up the master and remote systems. If portions of the system are not functional, problems that occur at the remote locations are not reported in a timely manner and therefore result in a visit to the site to troubleshoot the problem manually, a task that may take longer and cost more than if the system was maintained on a periodic basis.

The purpose of automation maintenance is to make sure that all portions are operating properly and minor issues (that don't cause a system shutdown or error) are addressed quickly. There are two halves of the system to maintain, the master location and the remote locations. Each has their own unique requirements. Below is a list of some of those items.

For the master station:

- Confirm that battery back up systems are operational
- Develop strategy/process to investigate and correct nuisance events.
- Verify that communications channels are not overloaded, especially if these are used for protective relaying schemes
- Database maintenance / housekeeping

For the remote control/ relaying units:

- Inspect for environmental damage such as water entry
- Confirm that battery back up systems are operational
- Download error logs, if available, to look for trends in error reporting
- Verify that messages are transmitted/received and that the communications devices' connections are undamaged.
- For equipment that can be bypassed, open/trip and close the switching device

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Annexes - Informative

Annex A Changes of Power Flow Due to Different Topology Scenarios

The effect of distribution automation on the relay operation is considerable, as the topology of the system changes. This, in turn, brings about many changes in the system parameters, such as voltages, currents, losses, and so on. The changes in topology are due to the need to reconfigure the system to satisfy two basic needs: to reduce Joule losses under normal operating condition or to restore service to the highest possible number of customers following fault isolation. This section will deal with the procedures of reconfiguration for both scenarios and the impact of this on the relay application and settings.

FEEDER RECONFIGURATION

Feeder reconfiguration consists of the modification of the topology of a network through the closing of a switch that links two feeders and the opening of another switch so as to maintain the radial condition of the feeders. The reconfiguration is carried out in order to have a better operating condition of the network and specifically to reduce the losses due to the Joule effect.

Theoretically, it is simple to determine whether or not a reconfiguration carried out on a system will result in a reduction of electrical losses. The reduction of losses could be calculated easily from the results of load flows run for the system configurations before and after the reconfiguration takes place. However, even for a small distribution system, the number of permutation options is so large that many load flow runs would be required, which makes the problem both very inefficient from the computation stand point and very impractical to be applied to on-line analysis.

One of the first works on feeder reconfiguration, proposed the heuristic method and was developed by Civanlar, S., Grainger, H., Yin, H., & Lee, S. The method considers the closing of a normally open link and the opening of another normally closed link in order to transfer load from a feeder with a higher voltage drop, to another with a higher voltage level so as to reduce the active losses produced in the system.

The method can be illustrated with the three feeder distribution system shown in Figure A.1, taken from the Civanlar et al paper. The dashed branches 15, 21 and 26 represent links among the feeders each with a normally open switch. On the other hand it is assumed that each branch has a sectionalizing switch. Both the sectionalizing and the tie switches are identified with the same numbers as the associated branch.

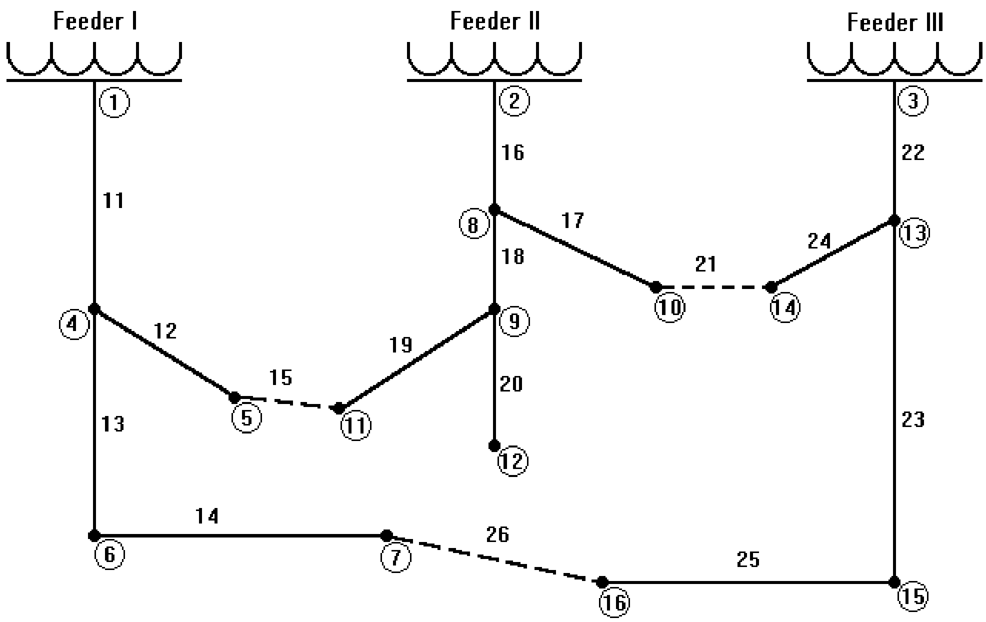

Figure A.1 - Three feeder distribution system

The load of node 11 can be transferred to feeder I by closing the link switch 15 and opening the switch 19. Likewise the loads of nodes 9, 11 and 12 can be transferred to feeder I by closing the link switch 15 and opening switch 18.

It can be demonstrated that there are 15 switching options for the system of the example. Actually the number of options is larger but some of them are eliminated directly if they cause that part of a feeder to become completely isolated. A loss reduction can be obtained only if there is a significant voltage difference across the link switch which is normally open and if the loads are transferred from the end with the higher voltage drop across the link switch. This criterion is the basis for discarding undesirable switching options.

The simplicity of the proposed methodology makes it very appropriate to monitor reduction losses in feeders. When the link switch 15 is closed, five opening options are available: 11, 12, 19, 18 and 16. When transferring loads from feeder I to feeder II, an increase in the losses is expected. $|E11|$ and $|E5|$ represent voltage drops at the corresponding nodes. (Therefore) If $|E11| > |E5|$, it is undesirable to open switches 11 or 12. Therefore there are three options associated with the closing of switch 15, corresponding to the opening of switches 19, 18 and 16 respectively. Likewise (since) if $|E10| > |E14|$, when the link switch 21 is closed, it is undesirable to open switches 22 and 24. Similarly, losses will increase when transferring loads from feeder III to feeder I when the switch 26 is closed and therefore the associated switchings are not considered.

Annex B One Company's History with Distribution Automation [20]

In 1949, Duquesne Light Company was already using distribution automation to some degree. Some distribution customers, who were willing to pay for improved reliability, were served by double tapped distribution facilities with automatic throw over on low-voltage circuits. Such practice was quite common for critical facilities, such as hospitals. These facilities use a break before make switching devices. Parallel operation was not an option.

In the 1960s System Planning conducted a 20 year planning study of the future of the 4 kV distribution system for Duquesne Light Company. It was discovered that at the current rate of growth, which was in excess of 5%, there would be a need to install 4 kV substations with 2000 kVA capacity spaced roughly 1 mile apart. In 1960, the decision was made to implement a transition from 4.16 kV to 23 kV as the distribution voltage. This decision was based upon the fact that, at that time, a 23 kV resistor grounded subtransmission system was in use. Changes in relay and breaker technology made it possible to implement an effectively grounded power system with the use of a four-wire multigrounded common–neutral distribution system with a nominal phase to phase operating voltage of 23 kV. The 23 kV distribution system was installed on poles that were five feet higher and the spacing of the conductors on the cross arm was increased over that used at 4.16 kV. Higher poles and greater conductor spacing was expected to result in better service reliability. That was true for a short period of time until the trees grew taller.

The subtransmission substations would become both 23 kV subtransmission stations as well as 23 kV distribution substations. The basic difference between the two services was that the 23 kV distribution system loads were all connected phase to neutral and the subtransmission system loads were connected phase to phase. Single phase subtransmission customer transformers were power class transformers with two primary bushing and the primary had a BIL of 150 kV. The 23 kV single phase distribution transformers had one primary bushing and the neutral of the transformer was internally connected to the tank. These transformers had a 125 kV BIL. Thus all the equipment used on the distribution circuit was distribution class equipment with a BIL of 125 kV.

As the system expanded during the 1960s, the customers' service reliability began to deteriorate since the area served by a single distribution circuit increased by a factor of five over that served by a 4.16 kV circuit. The Public Utility Commission in the early 1970s became disturbed by the number of customer service complaints it was receiving. It was made known to the company that something had to be done to improve the service to those customers served from the new 23 kV distribution system. Up until that point, little use had been made of sectionalizers and reclosers on the 23 kV distribution circuits. The decision was made that these devices needed to be considered and that they would be deployed as three phase devices. Each 23 kV distribution circuit was to be split into two or three sub-circuits just beyond the portion of the circuit between the substation and the first connected load, which was called the Feeder. The distribution circuit has three segments, Feeder, Main (Backbone) and Branch (Lateral).

The concept for the protection of the distribution circuit was developed. It addressed the following aspects:

Unbalanced load current on the circuit Feeder and Main had to be kept to less than 10% of the connected transformer capacity.

- The size of the connected load between each thee phase sectionalizer or recloser would be less than 5000 kVA.
- Maximum three phase fault current had to be limited to 12 kA or less.
- All distribution protection under normal service conditions had to be time or pickup coordinated.
- Protection scheme was designed to minimize the condition of undetected hot lines on the ground. This was the major reasoning for requiring that the load balance on the circuit be kept to 10% of the connected kVA or less at the substation and on each of the sections of the Mains.
- Every distribution circuit was designed to have sufficient ties to allow total transfer of connected circuit load or the sectionalized segment of the circuit.
- Each substation was equipped with fault recording equipment.
- All substation breakers were equipped with automatic reclosing capability that provided three steps of reclosing, instantaneous (approximate 20 ms), 15 s and 45 s.
- Substation beaker protection and three phase line recloser phase protection were set to carry 125% or more of the rating of that portion of the distribution circuit within their zone of protection.
- The substation protection was to consist of a three phase extremely inverse time overcurrent phase relay with instantaneous impedance relay. The impedance relay was set 50% through the largest three phase distribution transformer, 2500 kVA.
- Ground fault protection was provided at the substation by the ground overcurrent inverse time relays. (This was part of a fuse saving practice.)
- Since safety to the public was of the foremost concern, the goal was to install fault detection that would see the maximum number of creditable fault conditions and to safely isolate the faulted section. Typically, over 75% of the faults on an overhead (OH) distribution circuit are phase to ground; every effort was to be made during the selection of the 23 kV distribution circuit protection to detect all fault conditions and clear the fault quickly enough to prevent a burndown of a conductor. It was found from an AIEE/EEI study conducted between 1948 and 1952 that it is not possible to prevent the burndown of #6 copper conductors when the available fault current is greater than a few thousands amperes. Therefore, the minimum conductor size to be utilized was #2 copper or aluminum with equivalent ampere capacity.
- The three phase instantaneous impedance relay with an offset impedance characteristic was set so it did not see rated circuit load current but would be able to recognize a high impedance fault anywhere on the distribution circuit. The goal was to achieve highly sensitive fault protection but not see through the largest distribution transformer.

- The instantaneous phase distance relay was set 80% into the largest distribution transformer and the time over current relay was set at 160 A or about 26 % of the circuit phase protection overcurrent setting.

  (Experience showed that these settings were satisfactory. At the time that I retired from Duquesne Light Company in 2001, there never was a reported instance where there was a hot line on the ground. There was one incident of a pole fire where a line had come off of an insulator and set the wooden cross arm on fire.)
- The 23 kV distribution circuit sectionalizing scheme was designed to use a combination of substation breakers, two three phase sectionalizers in series and then a three phase line recloser followed by two more sectionalizers in series. This extensive scheme was never required because of the urban and suburban nature of the Duquesne Light Company service area.

Full-blown Distribution Automation

Even with this sectionalizing arrangement, it quickly became apparent that service reliability, from the customers view point, was not equal to a 4.16 kV circuit. A specification was prepared in 1975 for a redundant computer system that provided SCADA for the automated distribution sectionalizers and reclosers. In 1977, the development of a truly automated distribution system began. The distribution circuit breakers in the substation were also equipped with SCADA.

> (Duquesne Light Company was one of the companies that lead the industry in the use of monitor and control of the electrical facilities, starting around 1925 using a modified AutoCall fire alarm system operated at 250 V DC to monitor the position of the network protector.)

A simple philosophy was established in the specification for this HV distribution system:

- The system had to provide an easily managed mapping feature that would duplicate the current paper based operation maps.
- The linkage of the field device on the map had to be user friendly.
- There had to be a minimum of three tie points to an adjacent circuit to allow for restoration of the non faulted circuit following a fault.
- The only metering information was to be provided by the substation SCADA for the distribution circuits. Initially, only one phase of current was available to be reported by SCADA. In addition, three line to neutral voltages available from the SCADA. A pro rata calculation was made using the connected kVA beyond the protective device divided by the total circuit kVA and then multiplied the measured current obtained by SCADA at the substation to obtain an estimate of the actual load on each sectionalizer, recloser or fuse. This was done to minimize the cost of the system. The logic being that it was much better than the current practice at that time which was to install temporary recording meters to measure the current and voltage periodically at the location of the sectionalizing devices.
- Normally open sectionalizers were used at tie points between the distribution circuits. These were set for one count to lockout. The pickup of the counting device had to be insensitive to cold load inrush. The setting of one count to lockout was chosen to allow the distribution operator or automated control to close the sectionalizer into a fault. If the fault still existed on that portion of the circuit to be transferred to an alternated source it would cause the

alternate sources' breaker or recloser to open and then tie sectionalizer would lock open. This would prevent the fault from locking out the alternate energy source. All sectionalizers or reclosers had to be three phase devices with sensing being provided by phase and ground over current devices. No fusing was allowed in the Feeder or mains. Fuses were only to be used on laterals.

The computer system had to have the capability to operate in the closed loop mode or in the open loop mode to provide the operator guidance on the switching necessary to restore to the maximum number of customers in the shortest possible time after the fault was isolated by the station breaker, sectionalizer, recloser, or a fuse.

Information from the sectionalizers or reclosers was limited to their status (open or closed) and the condition of their control battery. Initially all the communication was via audio tones over private telephone circuits. These circuits were designed to be able to communicate with up to 10 sectionalizers. In some case it was possible to have satellite sectionalizers that were controlled via a DC loop with the master sectionalizer. The master sectionalizer had to have the ability to interface via the DC loop with the other sectionalizers in the area. The master sectionalizer was equipped with a simple SCADA function which could be extended to operate and monitor the remotely located sectionalizers. It was found to be economically feasible to limit this arrangement to a one mile radius from the master sectionalizer.

OPERATING EXPERIENCE

Although the system was designed to be completely automated and operate in a close loop mode, this feature was never implemented in practice. The main reason was that based on the SCADA information available to the distribution operator, they were able to make more informed service restoration decisions and could operate faster than the computer driven SCADA system already installed at the substations. Another reason was safety. The automated program was not to take over the switching until there was a settling time of 60 seconds after the breaker, recloser or sectionalizer reclosing had terminated. Then all of the switching functions used to return service to the unfaulted portion of the circuit was to be completed in less than two minutes. This could result in a maximum total customer outage time of three minutes. The setting time was chosen to allow temporary faults to be eliminated (examples: momentary tree contact due to wind, lightning incidents, etc.). The concern was that, if there was a line on the ground, it would be highly unlikely that the public would attempt to move a wire on the ground in less than 170 seconds. We did not want the automated distribution system to reenergize a fault after that time.

Another reason that the fully automated distribution control was never implemented was that the computer system only had 64K of memory. It was too slow for the distribution operator who could make a decision based upon the new information available faster than the computer was able to achieve

IMPACT OF DISTRIBUTION AUTOMATION ON PROTECTION

This philosophy had minimum impact upon the distribution circuit protection. The only new issue was that the protection on all of the circuits had to ensure that there was sufficiently sensitive protection devices on all circuits to be able to see a fault on the alternate circuit to which load was transferred to restore service.

EXPERIENCES AND RESULTS

- This semi-automatic distribution system has now been in service for over 30 years. If service can be restored after a fault, the restoration time is around 2 to 3 minutes.
- Three distribution operation centers were combined into one.
- Better utilization of circuit capacity resulted.
- It was possible to delay construction of new distribution circuit capacity.
- The company has seen a significant reduction of staff. The system has allowed fewer people to do more with less.
- Initially, it was estimated that the automation project would take 10 years and cost about $30 million. The final cost was very close to these numbers. Today there are approximately 1200 fully monitored and controlled sectionalizers and reclosers in service. The first generation of sectionalizers are being replaced with oil-less devices.

CONCLUSION

Distribution automation should not be done in a vacuum. It has to be a system level activity. It is important to involve distribution engineering, distribution protection, distribution planning and distribution operations.

- A first step is to establish a design and operation philosophy
- The protection should isolate the fault without a dependence upon communications.
- Switching and service restoration may depend upon communications
- In an extreme emergency, the communication system should be non-blocking.
- For safety reasons, consideration has to be given to time critical information and control. All information should be available to the computer or operator within less than two seconds.
- Consideration should be given to the data requirements needed for real-time operating conditions vs. archival type data.