INTERNATIONAL DRIVE
DISTRIBUTION AUTOMATION AND PROTECTION

James R. Fairman
Florida Power Corporation
3250 Bonnett Creek Rd.
Lake Buena Vista, Florida 32830
ph: (407)938-6657 fax: (407)938-6635
email: James.R.Fairman@fpc.com

Karl Zimmerman
Schweitzer Engineering Labs
115 Lincoln Place Court, Suite 102
Belleville, Illinois 62221
ph: (618)233-1010 fax: (618)233-1042
email: karlzi@selinc.com

Jeff W. Gregory
Schweitzer Engineering Labs
3124 West Main, Suite 10
Dothan, Alabama 36305
ph: (334)702-0595 fax: (334)702-0591
email: jeffgr@selinc.com

James K. Niemira
S&C Electric Company
6601 North Ridge Boulevard
Chicago, Illinois, 60626
ph: (773)338-1000 fax: (773)338-4254
email: jniemira@sandc.com

Introduction

Florida Progress Corp., St. Petersburg, Florida, is a Fortune 500, diversified electric utility holding company. Its principal subsidiary is Florida Power Corporation (FPC), the state's second largest utility, serving about 1.4 million customers, with a growth rate of 2% per year. FPC's service territory covers about 20,000 square miles, in 32 counties in central and northern Florida. A pending acquisition of Florida Progress Corp. by Carolina Power and Light Energy will result in a company that serves 2.8 million customers in a 50,000 square mile area.

Included in that service territory is the area around Orlando, Florida, the number one tourist destination in the entire world. One of the main tourist destinations is the area around International Drive (I-Drive), located south of Orlando. Attractions of I-Drive consist of large high-rise hotels, shopping, restaurants, and recreational facilities. The area is very aesthetically pleasing, including exquisite landscaping, roadway, and easement infrastructure. I-Drive is home to the 4 million square foot Orange County Convention Center as well. Concentrated in a 3-mile long area, the section of I-Drive that this protection and automation project dealt with consists of over 500 commercial customers, with a peak load of 45 megawatts, and a gross revenue of over $13 million per year. Within ¼ mile of this section of I-Drive is the service boundary of a neighboring electric utility. The competitive threat necessitated development of a state of the art distribution system of unusual reliability to avoid defection of loyal customers.

Before this project began, I-Drive was served by 6 radial feeders, including 8 miles of 1000 kcmil underground cable and 2 miles of 795 AAC overhead conductor. The 13-kV distribution system included 16 motor operated switches controlled by FPC's existing SCADA system through 900 MHz radios. Also, there were 21 manually operated switchgear units. In the 1990s, there were 29 feeder level outages; 16 of those were in 1998 alone. Ten cable dig-ins and twelve cable failures caused most of these outages. Many of these outages were lengthy, due to the poor performance of the SCADA system and the inability to get crews quickly into this congested area of I-Drive. That was not acceptable. Several key I-Drive customers indicated that not more than one outage every 3 to 4 years was a reasonable level of service. Thus the birth of this project.

Beginning in the fall of 1998, a tactical team was asked to develop and implement short-term tasks that would quickly mitigate the poor performance of this distribution system. The existing SCADA system was reviewed and determined to be questionable at best. The radio system did not work well due to interference from trees and high rise buildings. Radio signal strengths were measured and antennae were aimed towards the better of two receivers. Equipment grounding was evaluated and upgraded. The health of the underground feeder cables was reviewed and determined to be poor. As a result of both partial discharge testing and relaxation current testing, 27,000 ft of underground feeder cable was identified for immediate replacement.

In the same time frame, a strategic team was asked to look at long term opportunities to bring the electric service reliability up to the “superb” level that our customers demand and deserve. Six alternatives were evaluated with four being rejected because they did not adequately address the reliability concerns. An intelligent switching alternative and a primary network alternative were studied and pursued for further development. These systems would need to be installed and in-service by October 20, 1999. On November 12, 1998, FPC issued a request-for-proposal for an engineering study, recommendations, and equipment procurement. By asking suppliers to consider both types of systems in their proposals, FPC could ensure that the system would provide the superb level of reliability that these customers expect and do it at a competitive price.

The intelligent switching alternative would have a microprocessor-based controller at each switch location. It would continuously communicate with controllers at adjacent switches to determine and execute the best switching scheme for any feeder fault. This would be a looped-radial system with a normally open point. Reclosing would be included in the substation protection schemes to clear the faults and faults would be isolated by the sectionalizing action of the switches during the circuit dead-time between recloses. A brief interruption of several seconds would occur while automatic switching actions close the normally-open point and restore service to unaffected portions of the circuit. This alternative would require retrofitting existing switchgear with sensors, motor operators, and controls (or replacement of existing switchgear with new switchgear having these features). A communication system would also be required.

The primary network alternative would use directional relays and fault interrupting switchgear to dramatically reduce feeder outages. With this system, when a section of underground feeder level cable fails, automatic fault clearing will occur before the substation circuit-breaker trips. Customers will only see a few cycles of voltage sag until the fault is cleared, and no service interruptions. This primary network system would require replacement of all pad-mounted switchgear, installing some additional feeder ties and installing 4 new underground feeders. Also, relaying and fiber communications would be installed. Since these feeders would be in a loop configuration, with many tie points between them, there would be no need to have reclosing on the feeder breakers in the substations.

A reliability assessment on both alternatives was conducted to determine the impact of the ‘Lost Value Of Service’ (LVOS) and the expected outage frequency. The results of that reliability study indicated that both an intelligent switching system and a primary network system could be utilized to reduce the lost value of service. An intelligent switching system would not reduce the number of outages, but it would reduce the outage duration to less than 60 seconds for most customers. A primary network would eliminate outages caused by a feeder level cable failure but would have a greater installation cost and be a relatively high maintenance alternative.

The decision was not an easy one. The costs were going to be significant, close to $8 million for both the distribution and the fiber communications. FPC needed to consider both cost and reliability in its decision to provide these customers with a superb level of service. As the geographical area divided itself naturally into two types, overhead conductors on the north end of I-Drive and underground cable on the south end, the project was divided into two different solutions. For the overhead portion, the intelligent switching solution was chosen. For the underground portion, the primary network (4-loop) solution was chosen. A robust means of communications between each and every switch location on both portions of the project was chosen to be single mode, fully multiplexed optical fiber, installed in three closed communication loops. These fiber loops would be fully redundant, 4 fiber, hot stand-by configurations. The fiber loops would communicate back to each of two different substations. All SCADA communications would be via DNP 3.0 back to the substations. There the data would be concentrated and the protocol would be converted to a legacy protocol to be compatible with FPC's existing SCADA system. Analog data including 3-phase volts, amps, megawatts, megavars and several different alarm and status points would be brought to the data concentrator/protocol converters. Dial-up telephone access was not included. Fault records were to be stored in the relays and intelligent switch controls.

The relay protection schemes needed to be 'dependable' enough to operate correctly every time, 'secure' enough to not ever operate incorrectly, 'selective' enough to isolate the smallest segment of cable possible for any fault and 'sensitive' enough to protect for all types of faults. A large effort was made to keep the relay protection fast, simple, and cost effective. No single point of failure would be tolerated. These operating systems must be kept as simple as possible to facilitate operation and maintenance and system expansion.

In May 1999, a contract was signed between FPC and S&C for the engineering services. The installations would begin in June 1999. All installations and system checkouts had to be completed by the end of October 1999. The switchgear and relay manufacturers committed to the very aggressive timetable. All of the communication equipment manufacturers as well as the power cable suppliers committed to this schedule. The intelligent switching equipment manufacturer committed, as well. Arrangements were made for the construction contractors that would do the trenching and boring part of this work. Arrangements were made for all of the in-house construction support. This project had full FPC support from the highest levels of management, as well as the individual contributors. All contributors made a decision to be successful and to 'do it today.' No procrastination could be tolerated.

The real challenge of this project was not the installation of the 28,000 feet, or the replacement of 27,000 feet of existing, underground feeder cable. It was not the installation of the 4 new feeders, in 2 different substations. It was not the landscape restoration immediately after work was completed. It was not the installation of all of the new switchgear. It was not the installation of over 90 directional relays. It was not the nearly impossible timetable. It was not the project management time and effort. FPC does those types of things on a regular basis. The real challenge was the integration of all of the technologies into this new application. Every detail needed to be engineered. The relay/communication schemes needed to be dependable, secure, selective, and sensitive. The primary network 13-kV distribution system needed to clear all faults in less than 6 cycles. The microprocessor relays needed to be fast, allowing tripping in 2¼ cycles; they needed to be easy to set; they needed to be able to communicate via multiplexed fiber, relay to relay and to SCADA (control, status, and analogs) using both RS-485 and RS-232 connections. The relays had to be able to initiate tests of the control box battery. All switchgear trip and close functions had to be available through the relays. The relays needed to be able to perform certain automation functions. The relays needed to allow zone 1 and zone 2, primary (POTT), backup (DCB), and direct transfer trip (DTT) schemes to be active at the same time. The relays needed to be able to run self-diagnostics, reporting any abnormalities back immediately through SCADA. The communications needed to be able to accommodate all of these functions, at all 33 switchgear locations, while meeting a 4-second scan rate for all SCADA data.

Construction began in June 1999 with trenching and boring for the new feeder installation and for the fiber cables. Contractors began the installation of the equipment cabinets for the fiber optic system. FPC crews began the work of installing the new feeder positions, including directional relays, in the different substations. FPC crews began reworking the overhead and underground lines. Crews began replacing existing switchgear with new dead front, SF_6 fault-interrupting switchgear. FPC operations people developed and wrote the switching plans. Dispatching coordinated the switching. Relay/Telecommunication technicians began the checkout of the integration equipment. Engineers and programmers began work on the programming required to accommodate all of this new information in the SCADA system. The equipment supply partners continued their efforts to deliver all material on schedule. After a long hot summer and two hurricanes, the work was completed on October 20, 1999, ten hours ahead of the aggressive schedule's deadline.

Only through the commitment of the suppliers, contractors, and FPC distribution and transmission employees together, could a project of this complexity and magnitude be successfully completed on time and within budget. The real story told by this project and this paper is one of teamwork and commitment.

Protection System Overview

Electrical System

The distribution system supplying the I-Drive area is fed from two substations, Sand Lake and Orangewood, shown schematically in Figure 1. The load served from Sand Lake is a combination of overhead and underground cables. Orangewood feeders are underground. For simplicity, only the feeders are shown in Figure 1. Switchgear units typically have two feeder positions and two branch line positions to serve loads. For ties between loops, switchgear having three feeder positions and one branch line position is used.

Protection System

The design team established several criteria to maximize the system reliability:

- Serve load with a reliable, fault-tolerant system
- Automatically sectionalize a faulted feeder cable, otherwise maintain uninterrupted service
- Consider only first contingency cases in the automatic system
- Isolate each individual fault, restore service to as much of the load as possible in as short a time as possible

To achieve these goals, we implemented several protection schemes, some of which have proprietary features. For the overhead/underground radial feeders from Sand Lake, we used an automatic sectionalizing/service restoration system using peer-to-peer communications and distributed intelligence. For the underground loop systems, the protection uses a variety of pilot protection schemes and an automatic source transfer scheme.

Communications

The communication system plays a vital role in the functionality, security, and dependability of the protection and automation system. A four-fiber, hot-standby, self-healing T1 (24-channel) ring was selected to provide full connectivity and alternate routing should the primary communication path fail. The self-healing rings consist of 96-fiber cable and 36 multiplexers configured in three fiber optic loops that return to one of two substations. Only 4 fibers between each multiplexer are used for each loop of the communication system; the remaining fibers are saved for future use and are available for lease to other companies for their data transmission needs.

These fiber loops along with the multiplexers used in the communication system provide:

- A communication path from relay to relay. This relay-to-relay communication is used for pilot protection as well as information transfer.
- All SCADA communications:
  - Control
  - Status / Alarms
  - Analog values

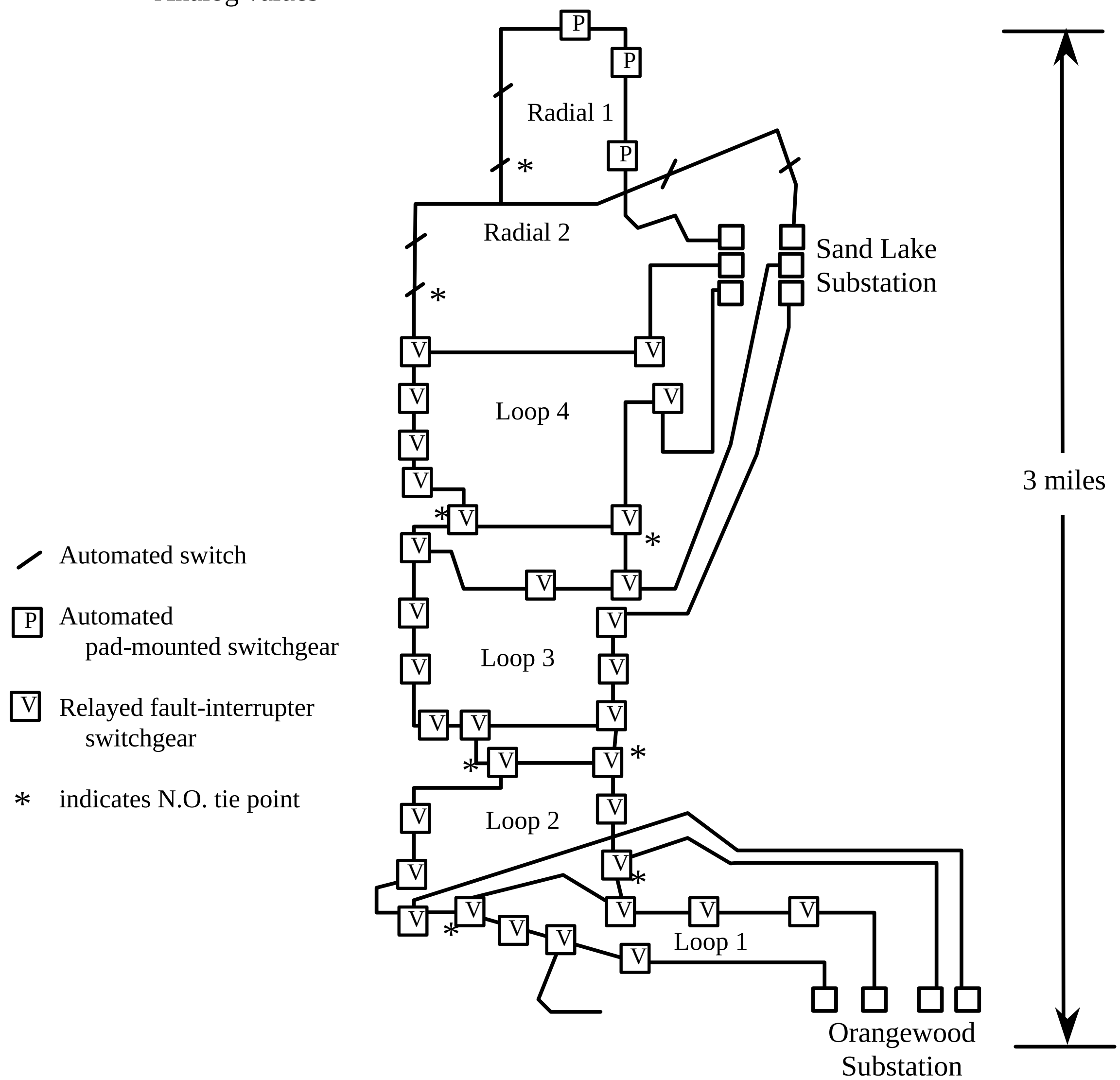

Figure 1: I-Drive Project Distribution System feeders. Branch lines to loads are not shown.

Communications with the switches and relays is accomplished via DNP 3.0 protocol back to the substations where the data is concentrated and converted to a legacy protocol for compatibility with FPC's existing SCADA system. It was important to the system operators that they have an accurate picture of the distribution system configuration at all times and that desired switching actions are implemented expediently. By judicious arrangement of the communications loops, number of channels on each loop, and number of IEDs ("intelligent electronic devices") per channel (maximum of 5), the desired 4-second scan rate was achieved.

Just as with the protection system, communication reliability is critical, and the 4-fiber, hot-standby, self-healing loops provide very reliable redundant communication paths with fast restoration times.

Underground system Relay-to-Relay Logic Communications and SCADA

Each relay is equipped with 4 serial ports. Two ports are used for relay-to-relay communications to support protection functions, one port is used for SCADA, and the remaining (front panel) port is used for local interrogation of the relay. Connection of the relay to the communications system is shown in Figure 2.

Two RS-232 ports are used to communicate with two remote relays over the fiber network for protection functions. The “A” channel is used for primary protection schemes and communicates with the relay at the opposite end of the feeder section. The “B” channel is used for the backup “overreaching” protection schemes and communicates with the relay at the far end of the adjacent feeder section, “reaching over” an intervening switchgear unit to do so. The delay through the fiber network is less than a millisecond, and the processing interval of the relays is ¼ cycle. Thus, the total communication time (from pickup of an element at one location to assertion at the intended recipient) is about ½ cycle. Each channel can send and receive up to eight logic points simultaneously. Thus, we can transmit and receive permissive trip, block trip, and direct transfer trip over the same channel in one-half cycle.

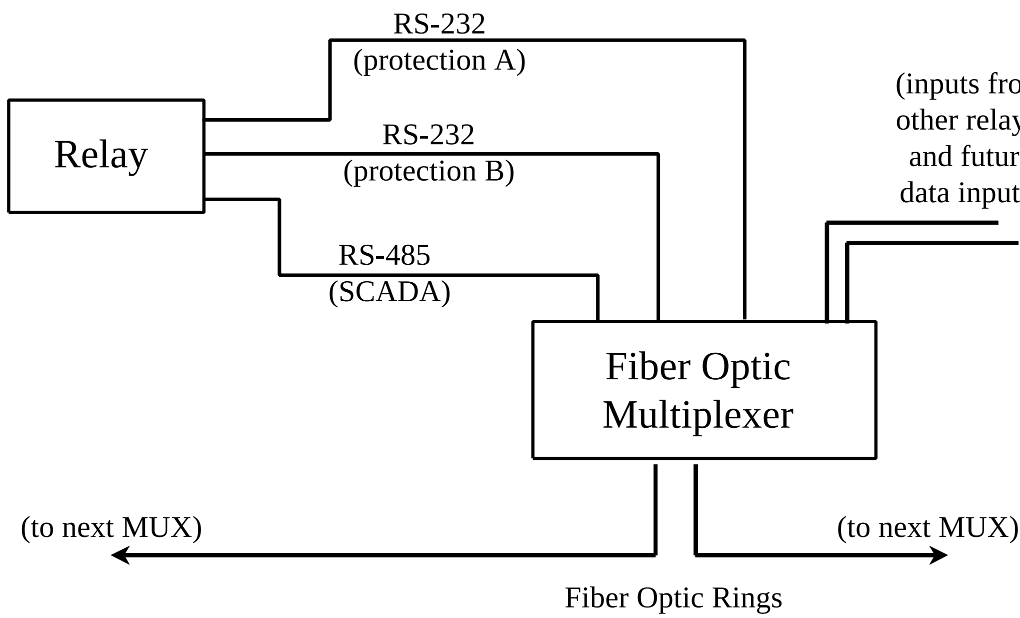

Figure 2: Connection of Relay to the Fiber Optic Communications Network

The third serial port is RS-485 addressable and is used for SCADA control and telemetry. Analog values (current, voltage, and power), status points, and alarms are transmitted back to a data concentrator at the substation. Remote control of the switch positions by the system operators is also achieved by communications through this port. All of the RS-485 ports at one geographic location are “daisy chained” before connection to the fiber optic multiplexer to conserve logical channels in the multiplexer and to conserve the hardware requirements.

Intelligent Switching System Communications

The same fiber optic network as used for the underground system is used for the intelligent switching systems. Each switch controller has three RS-232 ports, one for local programming and two for external communications. Using these ports, the switch controllers are connected one to the next with the fiber optic network providing a “virtual” hard wire connection from one controller to the next. The existence of the intervening fiber optic network is transparent to the switch controllers. The first or last controller in the string communicates SCADA information back to the substation data concentrator, again through the fiber optic network.

Protection of Underground Loop System

Each of the four underground loop feeders uses “pilot” protection principles to produce automatic high-speed fault clearing. The pilot protection schemes use relays equipped with directional overcurrent elements linked together by a high-speed fiber network. The relays also provide backup protection for branch feeder faults. Figure 1 shows the one-line diagram of main feeders of the distribution system. For simplicity, branch lines that serve the loads are not shown in the figure. Switchgear on the underground loops typically has two feeders and two branch lines; switchgear situated to allow ties between loops will have three feeders and one branch line. The feeder cable sections between switchgear units are treated as line sections, much like those of a transmission system. These cable sections vary in length from about 20 feet to several thousand feet.

The pilot protection schemes applied are:

- POTT (Permissive Overreaching Transfer Trip)
- DCB (Directional Comparison Blocking)
- Overreaching POTT/DCB Schemes
  - Time delayed to coordinate with source and load side devices

Protection equipment at each switchgear consists of:

- Directional overcurrent relays with multiple zones, programmable logic, and relay-to-relay communications logic for each feeder line
- Overcurrent controls for each branch line
- Fiber Optic network multiplexer with multiple inputs for RS-232, RS-485, and direct fiber connections

The directional relays use an adaptive negative- or zero-sequence impedance based directional element for unbalanced faults, and a positive-sequence voltage polarized element for three-phase faults.

POTT (Permissive Overreaching Transfer Trip) Scheme

The permissive overreaching transfer trip scheme uses forward looking phase and ground directional elements (67P2, 67G2) at each end of the line section, as indicated in Figure 3. If a forward fault occurs, the directional elements transmit (KEY) a permissive trip signal to the remote terminal. If a forward fault is detected and a permissive signal is received from the remote terminal, the fault interrupter is tripped and a direct transfer trip signal is sent to the remote terminal, provided that the communication signal is healthy. The permissive signal is also transmitted for an open breaker (52B) condition. The POTT control logic is illustrated in Figure 4. “A” indicates communication channel A.

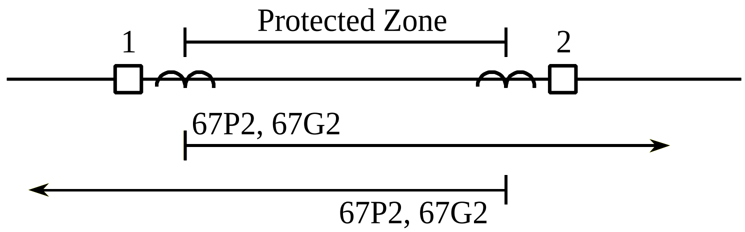

Figure 3: Basic POTT Scheme Protection

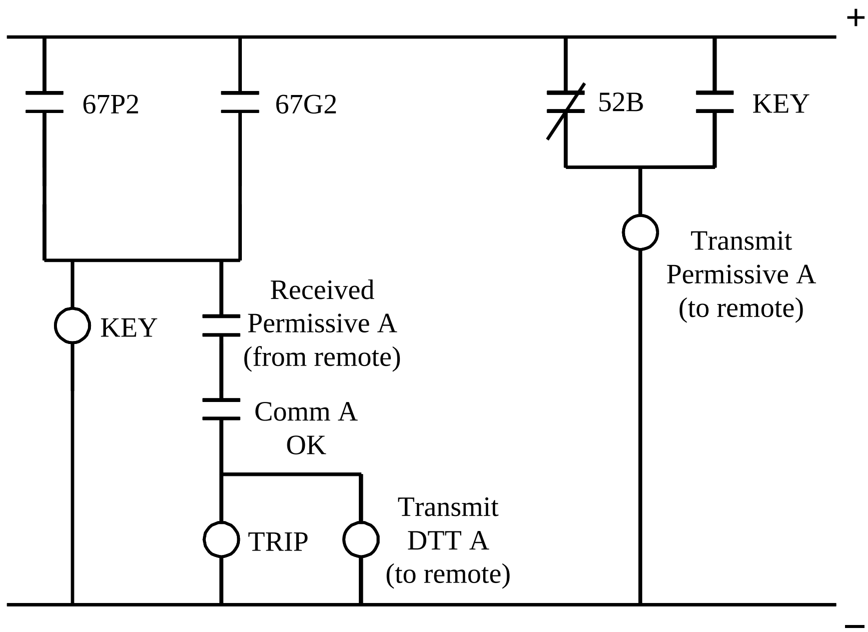

Figure 4: Control circuit representation of POTT logic

DCB (Directional Comparison Blocking) Scheme

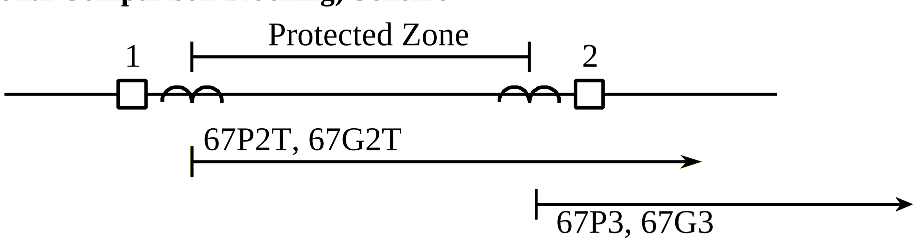

Figure 5: Basic DCB Scheme Protection

The directional comparison blocking (DCB) scheme is used in conjunction with the POTT scheme. The scheme uses forward and reverse looking phase and ground directional overcurrent elements (67P2T, 67G2T: forward; 67P3, 67G3: reverse), indicated in Figure 5. A short delay (3 cycles) is added to the forward elements to allow time for generating, transmitting, and processing of the blocking signal. If a forward fault is detected and a blocking signal from the remote terminal has not been received, we issue a trip and a direct transfer trip to the remote terminal, provided that the communication channel is healthy. The reverse elements (67P3, 67G3) transmit a block signal to the remote terminal. Blocking elements are set more sensitively than the remote forward reaching elements to avoid overtripping. The DCB control logic is illustrated in Figure 6.

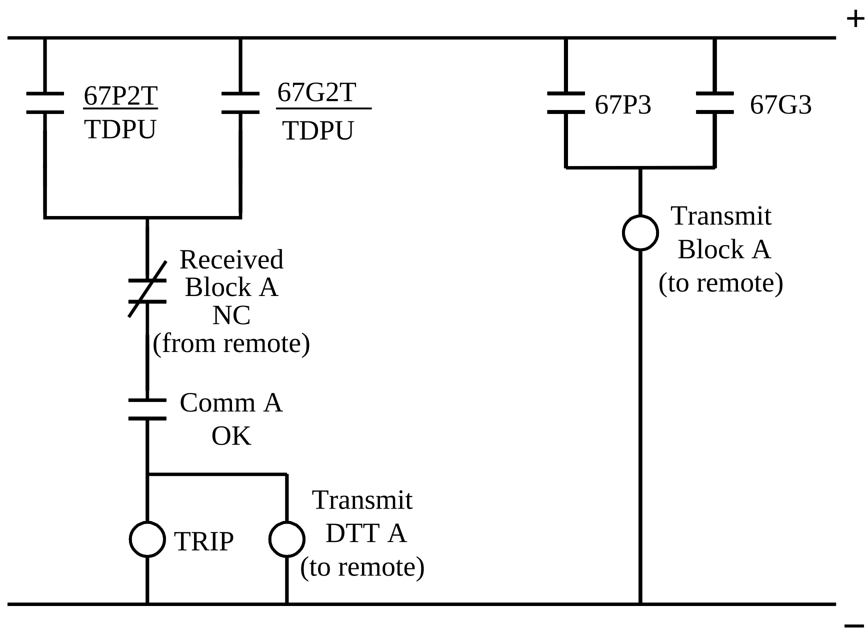

Figure 6: Control circuit representation of DCB logic

Both schemes (POTT and DCB) are operational at all times. The POTT scheme is faster, but having the DCB in service ensures that no setting changes must be made for open loop (radial) operation of the power system.

Backup Protection Using Overreaching POTT/DCB Scheme

Protection in the event of the possibility of relay, battery, or other equipment failure was considered a high priority. One of the scenarios is, what if an entire switchgear is damaged or unavailable (e.g., an auto accident)?

Standard (non-communicating) time coordinated backup protection was not possible due to the number of devices in series. Thus, we implemented an overreaching POTT/DCB scheme to backup the primary POTT and DCB schemes by using an additional communication path.

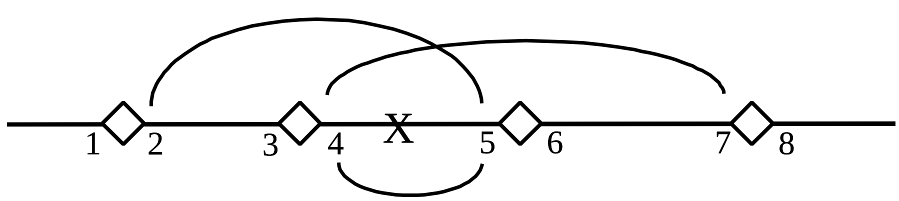

Figure 7: Tripping scenarios for Overreaching POTT/DCB Scheme; "X" indicates the fault location.

In Figure 7, for the fault shown, the primary scheme would trip breakers 4 & 5, and the two overreaching schemes would trip 2 & 5, and 4 & 7, respectively.

The backup overreaching POTT/DCB scheme works the same as the primary POTT and DCB schemes except that an inverse time overcurrent (51PT, 51GT) is used. The inverse characteristic coordinates with branch line protection (fuse-like characteristics), and also allows the primary POTT and DCB schemes to operate and allows for a coordination delay for the overreaching DCB blocking signal. In

Figure 8, elements 67P4, 67G4, 67P2, and 67G2 are forward directional elements; 67P3 and 67G3 are reverse directional elements.

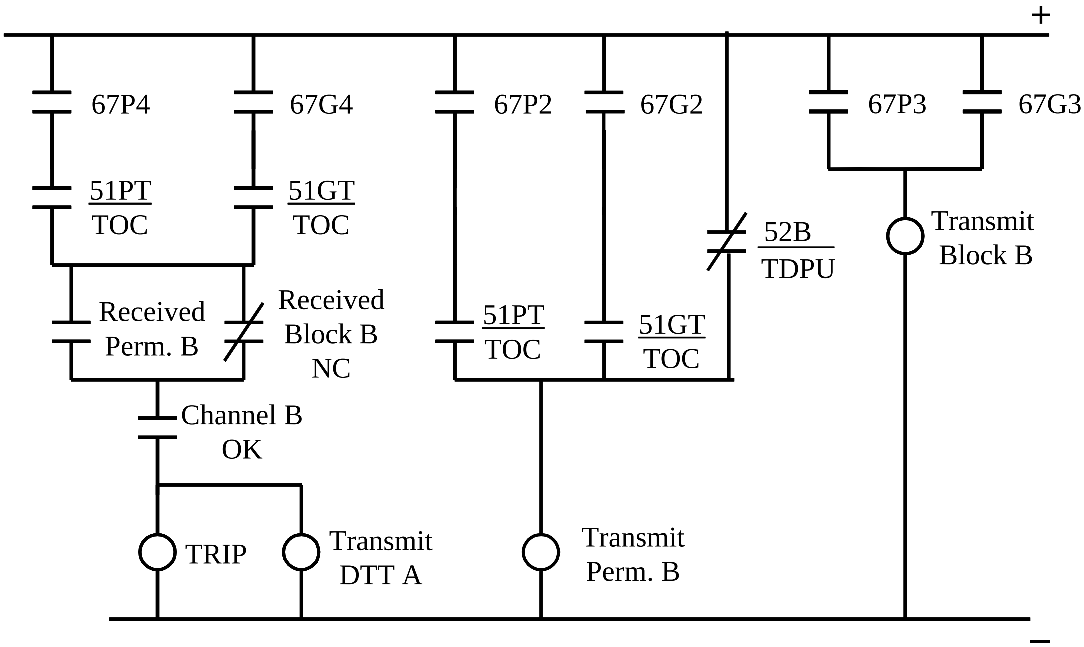

Figure 8: Control circuit representation of Overreaching POTT/DCB Scheme

Note that channel B is used for the overreaching communication scheme, channel A for the primary schemes.

Breaker Failure Protection

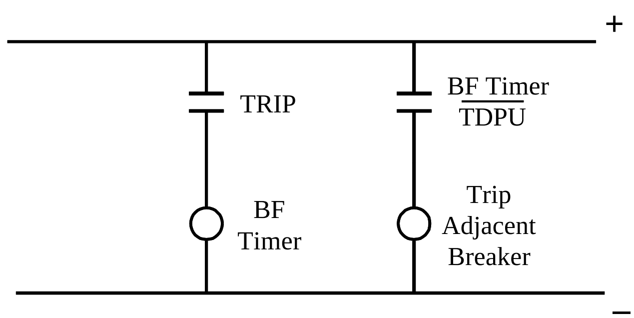

Figure 9: Control circuit representation of Breaker Failure Scheme

If a trip condition persists for 10 cycles (BF Timer), we initiate a breaker failure (BF) condition. This condition:

- Trips all other feeder interrupters in the switchgear (indicated as "adjacent breaker" in the logic diagram, Figure 9)
- Issues a direct transfer trip to the remote terminal and trips.

In a breaker failure scenario, BF will "race" with the overreaching POTT/DCB elements. Since the overreaching POTT/DCB elements operate on an inverse time curve, it is possible that breaker failure protection will operate faster, preventing an overtrip.

For the fault shown in Figure 10, and a breaker failure at 4:

- Breaker 3 trips directly, 2 by direct transfer trip (DTT)
- 2 & 5 trip by its respective overreaching POTT/DCB schemes (3 & 4 by DTT)
- 4 & 7 trip by the other overreaching POTT/DCB scheme (5 & 6 by DTT). Note that 7 will not trip on its overreaching scheme if the fault has already been cleared by 5 on the primary POTT/DCB scheme; then neither will 6 receive the DTT from 7.

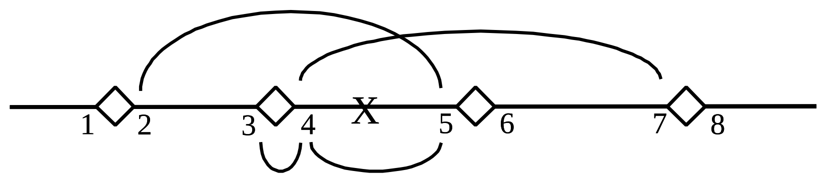

Figure 10: Tripping scenarios for Breaker Failure Scheme; "X" indicates the fault location.

Branch Line Protection

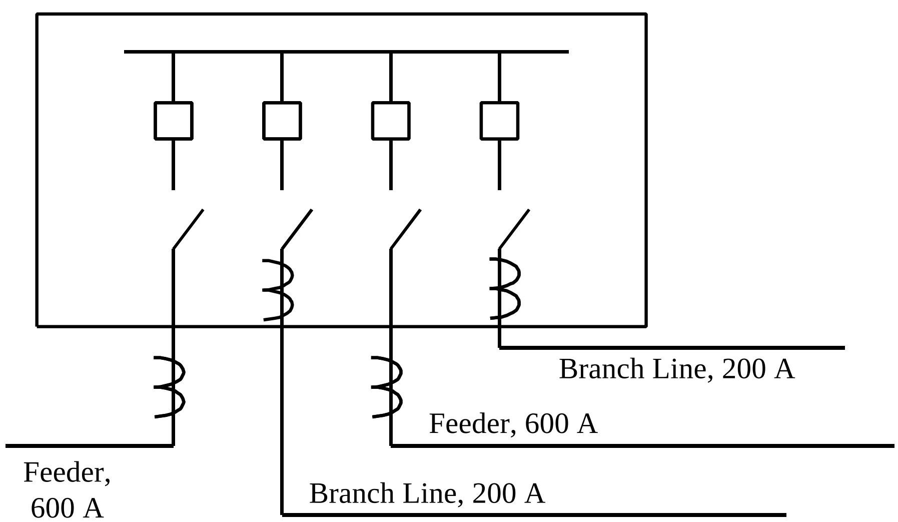

Figure 11: Switchgear one-line showing 600-amp Feeders and 200-amp Branch Lines

Each radial branch line (normally two per switchgear unit, as illustrated in Figure 11) is protected by a vacuum fault interrupter with an overcurrent control device. One overcurrent control provides tripping control for both of the 200-amp branch lines with separate settings for each branch line. The time-current characteristic (TCC) is similar to a fuse, except it is not affected by temperature or pre-load, has a higher continuous rating, and can be applied to trip single phase or three-phase. This relay is powered from the internal CTs for both control power and tripping energy – no battery is required. The branch line relay is coordinated with load-side weak-link fuses, and operates to clear faults above the rating of the weak-link fuses. Operating experience to date has shown that, with the fault current levels on the system, total fault clearing time is 2½ cycles when the branch line protection operates.

Note that while the CTs are external for the feeder relays, the branch line CTs are internal to the switchgear. Thus, the branch line protection includes the line bushing, elbow, and cable. (A fault on the feeder elbow is ordinarily protected by the bus fault protection zone. With an open-breaker condition, the feeder-elbow fault will also be in the primary POTT zone.) Also, in a few locations, the load current was greater than 200 A. For those locations, switchgear having 3 feeder positions was used, except the relay on the load position was programmed for non-directional time-overcurrent tripping to provide a 600 A branch line.

Bus Fault Protection

In order to protect for switchgear faults on the bus within the switchgear, including the elbow connections to feeders, and as backup for the branch line protection, one more scheme was added as indicated in Figure 12. Since each feeder line section is equipped with directional overcurrent elements, we used a reverse fault detection (32PR, 32GR) AND not forward (!67P2, !67G2) on the adjacent line to determine tripping conditions. In addition, these elements must coordinate with the branch lines to avoid trips for branch faults, so we applied inverse overcurrent (TOC) elements (51PT, 51GT). In addition to the "not forward" condition, tripping is also enabled by an open adjacent breaker (52B).

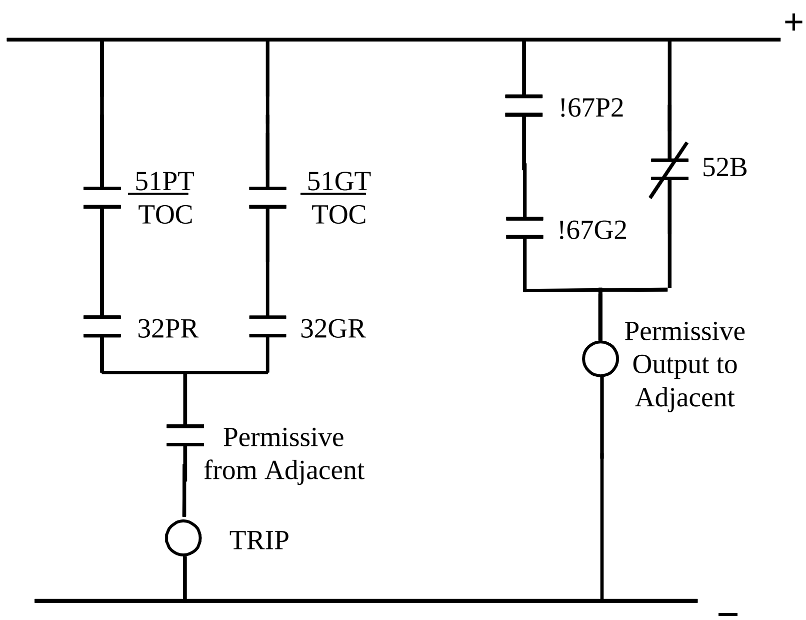

Figure 12: Control circuit representation for Bus Fault logic

For the bus fault shown in Figure 13, tripping can occur by two schemes:

- 3 & 4 trip by the bus fault scheme and send DTT to 2 & 5, respectively.
- 2 & 5 are tripped by overreaching POTT/DCB, and 3 & 4 by DTT.

Both schemes can trip. However, they are tripping the same breakers, so the protection requirements are satisfied. "Everybody wins the race."

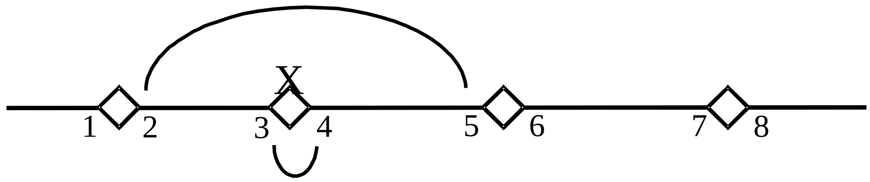

Figure 13: Bus Fault Tripping Scenario; “X” indicates the fault location.

Automatic Source Transfer

One final scheme was implemented to protect against loss of a substation bus at Orangewood Substation. An automatic source transfer causes connection of Loop 1 to Loop 2 in case either of these two loops should loose its normal source. Orangewood Substation has two busses with a tie circuit breaker; the bus tie automatically closes in case of loss of one transformer at the station. Loop 1 is supplied from one bus and Loop 2 from the other. In the case of loss of one transformer at the substation, automatic throw-over of the tie occurs and service is restored to both loops. However, in the case of a bus fault, the bus differential will clear the fault but there will be no source to the loop supplied by the faulted bus. In this case, the switchgear connecting to the next loop will detect loss of source on both of its two normally-closed feeder positions; after a time delay to coordinate with the substation throw-over, the tie-feeder will close, provided voltage is present on the alternate source. The control logic is illustrated in Figure 14. The scheme is interlocked to prevent closing if the loss of voltage was caused by the occurrence of a fault. Also, if the automatic closing does not occur during a short window of opportunity (for example if the alternate source is also not available) closing will not occur at all. The scheme is reset by return of good voltage on the normal feeders. Opening of the automatically-closed interrupter is performed by the system operators through SCADA or manually. This scheme is implemented in the four 3-feeder switchgear units that connect Loop 1 to Loop 2. For proper operation of the scheme one of the two “spur” feeders between these loops must be normally supplied from Loop 1 and the other normally supplied from Loop 2, so it is important that the normally open points as shown in Figure 1 be maintained. This automatic transfer scheme is not implemented on Loops 3 and 4 because the Sand Lake Substation uses a breaker-and-a-half scheme to provide protection against loss of a substation bus or transformer.

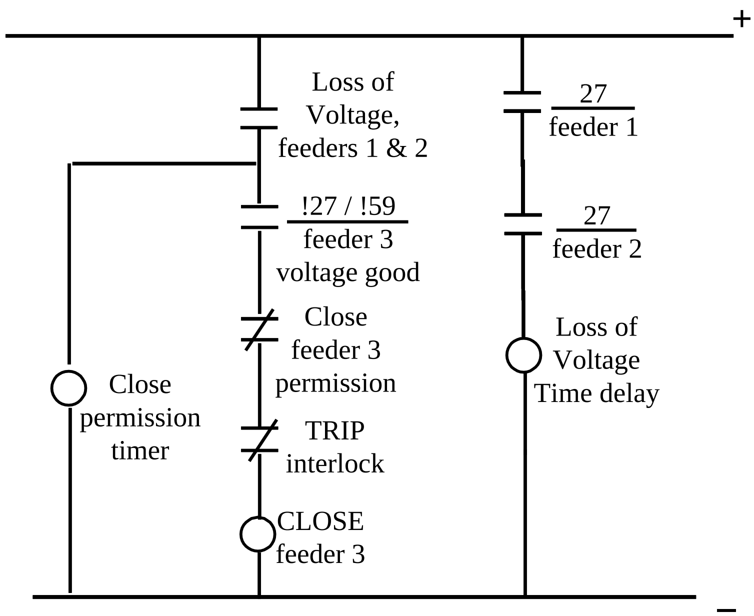

Figure 14: Control circuit representation of Automatic Source Transfer logic.

Automated Sectionalizing and Automatic Service Restoration System

In the north area of the system, the load density is not as high and overhead distribution is used. Because the loads are geographically dispersed, use of the fault interrupter switchgear was not possible in this area. Instead, intelligent switching systems were deployed in two "teams" to provide automatic transfer under loss of source conditions, automatic sectionalizing of faulted circuit elements, and automatic service restoration to loads on unfaulted line sections. One feeder is overhead construction, while the other has both an underground section and an overhead section. The intelligent controllers operate load-break switches, either in pad-mounted switchgear or SF_6-filled switches on the overhead lines. These two teams are shown schematically in the partial one-line diagram, Figure 15. Pad-mounted switchgear units have two controlled switches per controller.

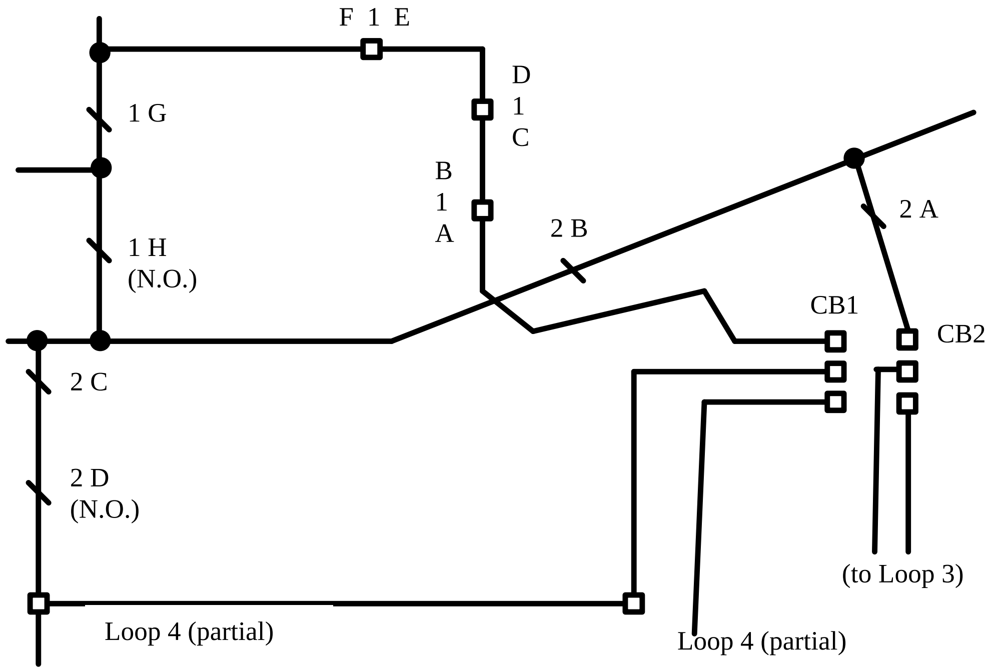

Figure 15: Partial one-line, intelligent switching systems. Overhead team 2 serves also as alternate source for team 1; underground Loop 4 provides the alternate source for team 2.

The switch controllers use peer-to-peer communications and accommodate radio, direct hard-wire connection, or fiber optics. In the International Drive area, radio communication was dismissed because of lightning interference and the concern of future construction causing interference with the radio communication channel. It was decided to use a "virtual" hard wire connection by interfacing the controllers to the same multiplexed fiber optic network as used on the underground protection system. Using the peer-to-peer communication, all switch controllers hear the messages from all other controllers, but each responds only to messages addressed to it.

The switch controllers of each team share and continuously update a database of information about the team status, the presence of good voltage, and power system loading. Each team member in turn updates its copy of the database with new information received from one neighboring member and with new data from current and voltage sensors at its own location; updates are then passed to the neighboring team member on the other side. In this way, all team members are continually aware of the status of all other team members and power system loading throughout the system. Interrogation of the entire team status and loading is achieved through SCADA or in the field by viewing the LCD display at any one of the switch controls.

Basic fault isolation operates as a sectionalizing scheme applied on a looped-radial system with a normally open point. For the overhead feeder (radial 2), the substation circuit breaker is set for four trips (three recloses) to lock-out. Controlled switches are field-configured with phase- and ground-overcurrent pickup levels and for three-shot sectionalizing. When a fault occurs, switches on the source side of the fault will detect over current followed by loss of voltage when the breaker operates. Switches on the load side of the fault will detect loss of voltage with no overcurrent. The first two recloses (one instantaneous and one time-delayed) allow clearing of temporary faults without reconfiguring the circuit. After the set number of shots, the switches automatically and autonomously open during the circuit dead time (i.e., while the circuit breaker is open) to isolate the faulted line section – communication is not required for initial sectionalizing to occur. The final reclose of the breaker restores service up to the first switch; the sectionalizing action of the switches isolates the fault to prevent lockout of the circuit breaker. (The exception is a permanent fault between the substation circuit breaker and the first switch, in which case the circuit breaker operates to lockout to completely isolate the fault.) As each switch opens, it communicates to the others (unsolicited report by exception) that it has opened and why, whether due to “fault” or simply “loss of voltage.” Each controller can then determine the location of the fault for the subsequent automatic service restoration. Temporary faults as may occur due to insulator flashover during lightning storms are cleared by the circuit breaker operation and service is restored to all customers by allowing the first two recloses with no sectionalizing. Permanent faults, for example due to downed lines or broken equipment, are isolated by the autonomous sectionalizing action of the switches. The intelligent controls continue to update the shared database, indicating the new status of the switches and the reason for the opening operation; that is, whether opening was caused as result of a fault or just because of loss of voltage. The intelligent controller also detects unbalance conditions as might be caused by open phase conductors. The controller will operate its switch to isolate the line section under such conditions, provided the current is within the rating of the switch. On the underground/overhead feeder, operation is similar except the circuit breaker is set for three trips to lockout (two recloses) and the switches are set for two shot sectionalizing. Temporary faults can occur on the overhead section, so an attempt at reclosing is reasonable. But because faults are not likely to be temporary on the underground portion, additional recloses will only increase the damage caused by faults on this section.

Automatic service restoration takes place after the line has been successfully sectionalized to isolate the faulted section. Using the shared database information, each controller determines the fault location and makes the decision to close either onto the alternate source or back onto the original source, leaving the faulted line section open. Actual pre-fault line loading is known by each controller, and this information prevents overloading of the alternate source. The switch will only close if the additional load to be added will not cause the total to exceed the field-configured pre-set limit. In the most onerous case, the entire load will be placed on the alternate source. Automatic service restoration time is less than 60 seconds.

After restoring service to as many customers as possible, the switching system goes into a “not ready” state. Switch status and analogs (voltage, current) are always communicated back to the system operators by SCADA, so the control room is also immediately aware of the disturbance. After the power system is repaired, the system operators give the signal for “return to normal.” Automatic return to normal is also possible when the switches detect return of voltage on the originally-faulted line section. This option was disabled because the system operators preferred to maintain control of the switching back to normal configuration. The switching system then reconfigures to the normal status. A closed-transition (paralleling of circuits during return to normal) was chosen to avoid “blinking” the customers, as would occur with an open transition.

Summary

A high number of outages due to cable failures and construction dig-ins precipitated the need for a high-reliability distribution system in the International Drive resort area south of Orlando, Florida. A primary network system was implemented on the underground portion of the system using SF_6-insulated vacuum interrupter switchgear controlled by microprocessor-based relays. Protection schemes implemented included primary POTT/DCB, backup overreaching POTT/DCB, bus fault protection, breaker failure, and automatic source transfer. Primary schemes will clear feeder faults in 6 cycles or less. On the overhead and combined overhead/underground portions of the distribution system an intelligent switching system was implemented to automatically sectionalize a faulted line section and automatically reconfigure to restore service to unfaulted sections in 60 seconds or less. Both the systems provide SCADA control, status, and analog data back to the system control center for real-time information about system status and loading. Communications for the relay protection and SCADA was achieved using fiber optic multiplexer system. Data for the protection system is transmitted end to end with less than ½ cycle delay; for the SCADA, a scan rate of 4 seconds was achieved. The optic system uses a 4-fiber hot-standby ring topology having redundant paths and redundant fibers for reliability. The protection and control system was commissioned on time and within budget, meeting a very aggressive installation schedule. It was only through the commitment and teamwork of the key suppliers, contractors, and FPC distribution and transmission employees that this project was successful.

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Biographies

James R. Fairman received his BSET degree from Purdue University in 1976. Also, he has a degree from Purdue University in Supervision, AS, 1975. He began his career with Northern Indiana Public Service Company, as a Relay Engineer, in 1974. In 1990, he joined Florida Power Corporation as a System Protection and Control Supervisor.

Karl Zimmerman received a BSEE degree from the University of Illinois at Urbana-Champaign in 1982, and has worked in the field of system protection for over 18 years. He joined Schweitzer Engineering Labs in 1991 and is presently a Regional Service Manager in Belleville, Illinois, where he provides technical support for relay engineers in the power industry. Karl has authored several papers on transmission and distribution protection and is a past speaker at many technical conferences, including the Western Protective Relay Conference, Texas A&M, and MIPSYCON. He is an active member of the IEEE Power System Relaying Committee and is chairman of Working Group D2 on Fault Locating.

Jeff W. Gregory, P.E., received his BSEE degree from Auburn University in 1989. From graduation in 1989 until February 1996, he worked as a Transmission and Distribution Engineer with Alabama Electric Cooperative in Andalusia, AL. In 1996, he left Alabama Electric Cooperative and joined Schweitzer Engineering Labs as a Field Application Engineer covering the Southeastern United States. He was promoted to Regional Service Manager for the Southeast, Carolina's, and lower Northeast territories in June 1999. He is a registered Professional Engineer in the State of Alabama.

James K. Niemira, P.E., received his BSEE from the University of Missouri at Rolla in 1985. In 1986, he earned the Master of Engineering in Electric Power from Rensselaer Polytechnic Institute. His work for S&C Electric Company has included various engineering capacities in R&D, product design, and

Power Systems Services. He is presently Senior Engineer and Project Manager working in the areas of power systems studies, substation design, and distribution system automation. He holds several US Patents and is a registered Professional Engineer in Illinois.