PROTECTION, CONTROL AND AUTOMATION FOR A MULTISTATION LOOPED DISTRIBUTION SYSTEM - PART I

By David Charles, ESCO Engineering and Testing; Ryan McDaniel and Michael Dood, Schweitzer Engineering Laboratories, Inc.

This article describes the protection, control, and automation system developed for a distribution system consisting of 2 generators and 14 substations that are on 3 loops. This project updated the protection and control scheme and added Supervisory Control and Data Acquisition (SCADA) to the site.

The design is based on installing multifunctional microprocessor relays at all remote sites and on the corresponding loop circuit breakers in the 13.8 kV switchgear at the Power Plant. Protection is accomplished using programmable functions in each relay and multicast Ethernet messages to mirror data from one relay to others at adjacent substations on each loop. SCADA is accomplished by directly accessing the Human Machine Interface (HMI) and software provided with the relays. A diesel generator transfer-switching scheme was installed that utilizes existing circuit elements with the installation of new digital generator controls and a second peer-to-peer communication method. Control and supervision of generation operation is provided through the HMI. The communication system is made up of a fiber-optic backbone that runs throughout the complex.

The fiber-optic communication system is the backbone that provides the ability to support the first three of four applications performed by the relay:

1. Distributed Network Protocol (DNP) LAN/WAN to provide SCADA information to HMI's to monitor and operate the facility.
2. Telnet, FTP, and SEL protocol to provide remote engineering access to monitor and set protection devices.

These protocols also allow access to oscillography data, sequential event records (SER), and maintenance data from these devices.

3. IEC 61850 GSSE, also known as UCA2 GOOSE, to provide Permissive Overreach Transfer Trip (POTT) communications.
4. A high-speed, secure protocol is used to perform main bus and tie transfer schemes.

I. INTRODUCTION

A large industrial customer engaged the services of the ESCO Group to upgrade the protection scheme and design a Supervisory Control and Data Acquisition (SCADA) system for its South 13.8 kV Electric Distribution System. This distribution system is similar to those used in many industrial sites as well as large universities. These contracted services included the design, settings, configuration, and commissioning of these systems. The overall project required automating switching and coordination of the loop circuits supplying industrial loads, control and operation of on-site generators supplying power to each loop bus, and control and automation of utility power supply switching, all integrated into one SCADA system with a Human Machine Interface (HMI) for electric department operations. The generator transfer switching for the two 3750 kW generators required installing new electronic engine controls, a new protective relay interface, and integrating the controls into the SCADA network. Communication among devices was designated to be Ethernet using dedicated fibers of the site's backbone system.

The HMI operator information is to be available at any location with Ethernet access to the SCADA network.

In a departure from the typical project sequence of hiring a consultant to design the system, hiring a contractor to purchase materials and install the system, and making the system work after the consultant and contractor have given up, the electric department decided this time the proposed system would be designed, programmed, simulated in a lab environment, and thoroughly demonstrated before installation activities commenced. Furthermore, they wanted to work with a firm that had designed, installed, tested, and commissioned SCADA systems to put all the responsibility associated with the project with one entity. After soliciting proposals from several equipment suppliers whom offered engineering services, the customer selected ESCO Group on the basis of not representing any one particular solution. ESCO Group had demonstrated experience in each aspect of the project and they also had the proximity to support the project after start-up.

The customer's directive to ESCO Group was to use the latest technology with a proven history using as few moving parts as possible that could be maintained with the existing facilities resources. Instead of a "Do it Today" mentality, the customer's philosophy was do it right so that it works when installed.

II. EXISTING ELECTRIC SYSTEM

The customer's electric distribution system is divided into two distinct distribution systems served from two sources by the regional Investor-Owned Utility. A one-line diagram of the south system is shown in Fig. 1. The 13.8 kV switchgear located at the power suppliers Substation U is owned by the customer. As shown in the one-line diagram, the 13.8 kV switchgear is connected in a main-tie-main bus configuration with local backup generation. Breaker 1 feeds Bus 4 from Utility Source 1 while Breaker 11 feeds Bus 5 from Utility Source 2. The tie breaker (Breaker 6) is normally open. Should one of the utility sources be lost, the corresponding main will open and the tie breaker will close to pick up the lost bus. If both sources are lost, the generators connected to Breakers 5 and 7 will

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come online and feed loads. It is also possible to operate the generators in parallel with the utility source if needed for additional load support.

The feeder breakers connected to the 13.8 kV bus feed a looped distribution system with multiple substations that span the customer's site. Each of these distribution substations has a distribution transformer that is connected between two breakers. One of the breakers is fed from 13.8 kV Bus 4 while the other breaker is fed from 13.8 kV Bus 5. While this type of distribution system provides for increased reliability, protection for this looped system requires more care than a typical radial distribution system.

The switchgear was installed during the late 1980s and has been well maintained, but the electromechanical relaying has become outdated. There was no initial provision for remote operation of circuit breakers or data acquisition. Over the years, the residues of various propriety systems installed to collect load flow information have remained. This project provided the opportunity to remove all this legacy equipment.

The remote substations serving the various facility buildings have equipment from a hodge-podge of suppliers. Each loop has grown and been reconfigured as buildings were added or equipment replaced. The electric distribution department can only designate what the configuration of the building electrical supply is to look like. The actual design and selection of distribution equipment is a combination of the engineer/architect hired to design the facility, and the general contractor with the lowest bid to construct the building. Although each substation consists of a breaker on either side of the loop supplying a fused disconnect switch for the building transformer, a variety of manufacturers is represented with protective relaying consisting of the flavor-of-the-day or firesale bargains. Loop coordination is achieved by sequencing time-overcurrent settings, starting from the innermost loop working out to the bus circuit breaker supplying the loop in accordance with a scheme that now only exists in the Westinghouse Electric Corporation Applied Protective Relaying [1]. Coordination has suffered from diminishing time separation of the protective relay settings, failure to apply the coordination philosophy correctly, inconsistent updates of the relay settings to reflect a change, and a multiplicity of relay types and settings. Consequently, outages require the distribution department to first determine where the fault occurred, physically break the system apart, and restore service sequentially until the fault condition is isolated for repair. This often leads to a one- to two-hour outage, which may have been tolerated 20 years ago, but today, arouses the irritation of management.

The existing generator controls consist of several refrigerator-sized cubicles covered on the exterior with lights, dials, switches, relays, and meters, and are stuffed full on the inside

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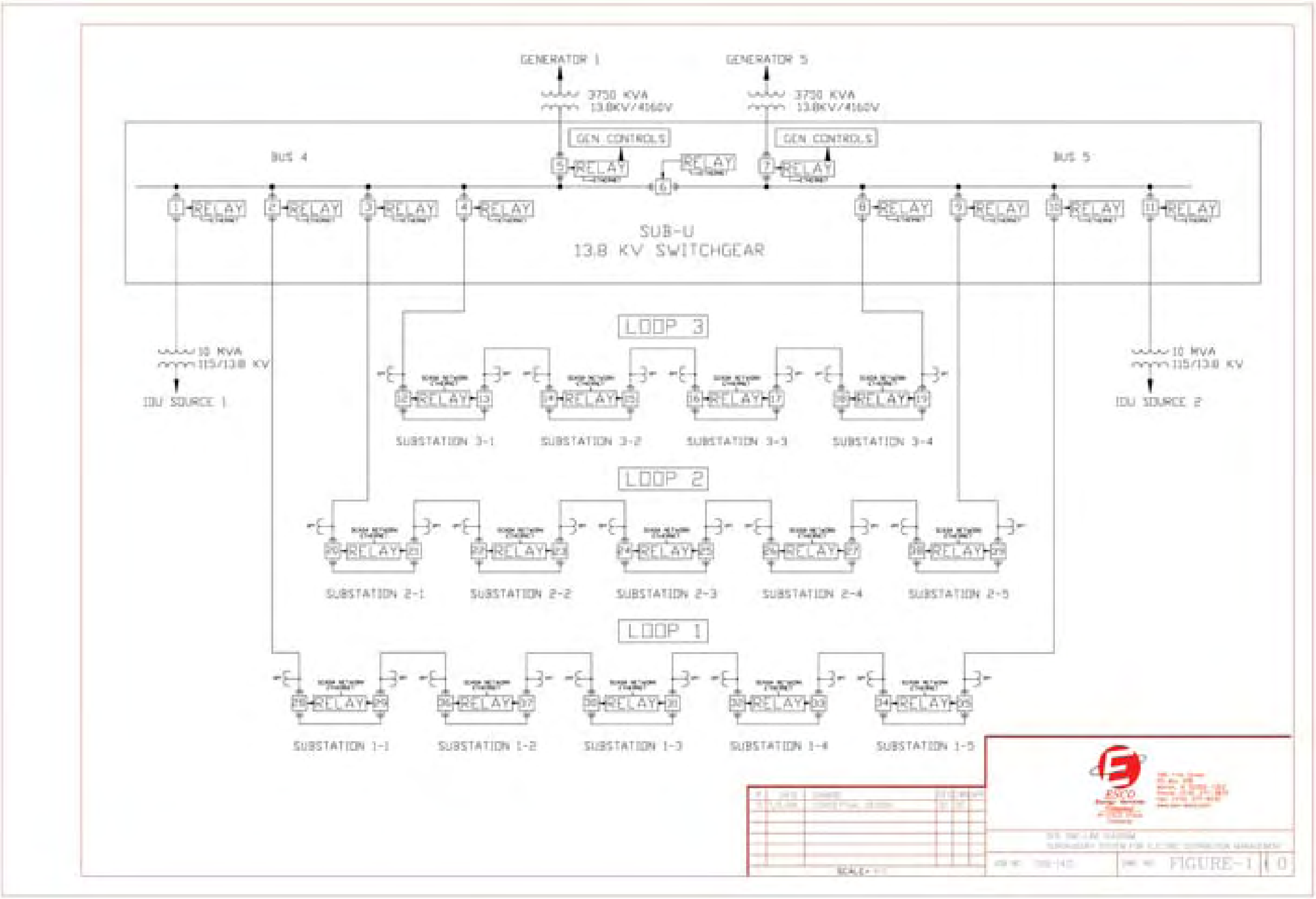

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with relays, transducers, control devices, timers, and more indicating lights, dials, switches, and meters. The modes of operation were intended to support running in parallel with the power source and standby operation for loss of source power. Both generation units do not operate in parallel, even though the same transmission source is supplying both buses, and never seem to operate for a loss of source power.

III. PROJECT STATEMENT

A condensed set of criteria for a new protection and SCADA system are based on the following statements made by the customer:

1. Simplify the protection and control schemes by eliminating a multiplicity of discrete relays and components with one device that can be used to satisfy all required applications. The goal being to reduce training requirements and issues in dealing with different manufacturers. The customer also wanted to reduce the number of protective relay configuration software packages to one.
2. Improve the automatic and manual operations of the system. The existing schemes were either not useful because they were not automatic enough or they were not understood enough by the operators. The requirement of this project was to make these schemes intuitive to eliminate operator mistakes in maintaining the power system.
3. Improve the coordination of the system to eliminate ongoing over-tripping that was being experienced. Thus the requirement was to isolate the fault by dropping the smallest amount of load. They also required that fault location and type data be available without operator intervention from the SCADA HMI to assist them in expediting restoration.
4. Provide the capability to obtain fault event recorder information and sequential event recorder data from anywhere on the SCADA communication network without requiring travel to the relay location.
5. Provide an HMI SCADA system that has two control stations and five view-only stations that can be loaded on a commercial off-the-shelf desktop or laptop computer.

This computer should be able to work from any Ethernet connection on the SCADA communication network. They emphasized that this investment in the SCADA system should be able to be supported for a long time so it should not be a proprietary system.

6. All of the communication protocols must run on the customer's fiber system on a dedicated network using Ethernet topology. It will be maintained by the IT department. It was recognized that there would be different speed requirements for different applications.

For instance, the pilot scheme requires communication speed in cycles while the SCADA HMI requires update times in seconds. It was required that none of the conversations could degrade the overall performance of its application or of any other application.

IV. SYSTEM DESCRIPTION (PRODUCT SELECTION)

To properly protect the electric system reliably and be cost effective, a multifunctional relay with flexible logic, multiple current and voltage inputs, and robust communications was needed. The same device should be used, if possible, to protect, control, and automate the following:

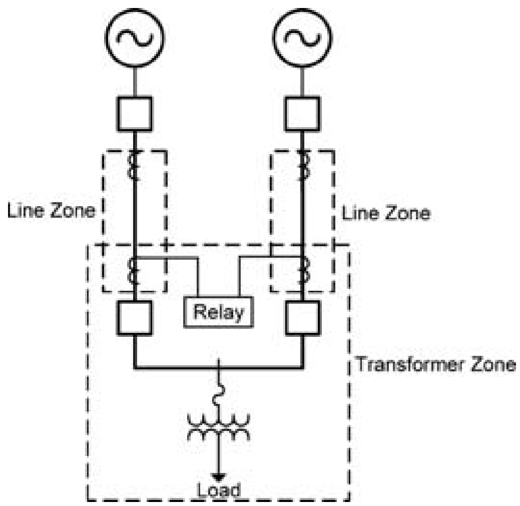


Fig. 2. Relay Protection Zones for Remote Substations

- Automatic main and tie transfer scheme on the 13.8 kV bus
- Generator breaker synchronizing control and generator protection
- Overcurrent protection for the main and tie breakers on the 13.8 kV bus
- Overcurrent protection for the feeder breakers on the 13.8 kV bus
- Directional overcurrent pilot protection for each of the breakers in the small distribution substations
- Overcurrent protection for the transformer in each of the small distribution stations

The relay selected to protect and automate this system had the following capabilities:

- Configurable operator interface with programmable pushbuttons
- Distributed Network Protocol 3.0 (DNP3) and IEC 61850 GSSE Communications
- Ethernet interface
- Relay-to-relay communication with MIRRORED BITS communications
- Flexible logic for both protection and automation functions
- Six AC current inputs and six AC voltage inputs to allow protection and control of two breakers
- Up to 23 DC inputs and 38 output contacts available
- Six configurable time-overcurrent elements

The relay features meet the requirements of remote substation control, protection, and automation. Supervisory control and data acquisition are accomplished by directly accessing the devices through a Wonderware HMI using DNP3 protocol. A software program provided free by the relay manufacturer and loaded on the same computer running the HMI software provides direct access to each relay through the Ethernet SCADA network using FTP, Telnet, and SEL protocols.

Main bus and tie transfer schemes are supported by MIRRORED BITS communications available on each of three serial ports.

Permissive Overreach Transfer Trip (POTT) communications is supported via an Ethernet multicast message (IEC

61850 GSSE, also known as UCA2 GOOSE).

Originally designed as part of the UCA2 protocol suite and given the name GOOSE (Generic Object Oriented Substation Event), the message was merged into the newer IEC 61850 standard and renamed GSSE (Generic Substation Status Event). This was done so that a new message with different capabilities within the 61850 standard could be named GOOSE. Both 61850 GOOSE and GSSE are useful, co-exist on Ethernet networks, and are collectively known as GSE (Generic Substation Events). For the purpose of this specific design, either could have been chosen. Some design selections predated the publication of the IEC 61850 standard and so 61850 GSSE (UCA2 GOOSE) was used. However, if done today, IEC 61850 GOOSE would be recommended. Since both can accomplish this design, further references in this article use the term GOOSE.

A detailed discussion of each aspect of the project follows.

V. REMOTE SUBSTATIONS

At each remote substation, there are three zones of protection: two zones of line protection for each incoming source and one zone of transformer protection that feeds the load at each distribution station. While the transformer is fused, it is necessary to protect the bus that the transformer is connected to as well as provide backup transformer protection.

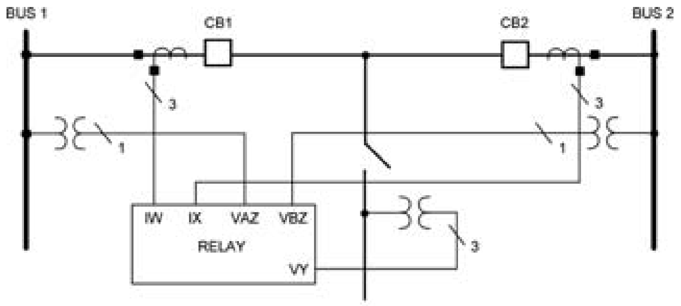
Conventionally, three relays would be required to properly protect the station and incoming sources. However, the relay chosen has two sets of current inputs and extensive logic available that, when implemented properly, can protect all three zones with only one relay. Fig. 2 shows the three zones of protection that the single relay will protect at each remote distribution substation.

To accomplish the protection needed with one relay, the relay must have the ability to sum currents from each CT to provide transformer protection. Also, each individual CT must be able to protect its respective line as well. Since the line is in a loop scheme, it will be necessary to have a directional comparison scheme on each line to provide the fastest and most secure protection. This will require a directional element for each current input and the ability to communicate with each remote terminal.

The relay selected has settings built in to protect a ring bus or breaker-and-a-half configuration, as shown in Fig. 3. For convention, the manufacturer defines the Breaker 1 current input as IW and the Breaker 2 current input as IX. In this scheme, both current inputs are summed inside the relay to protect the line. However, the internal directional element is also used for this same line protection. So, this configuration allows for protection and metering of the transformer zone using the line protection settings, but it does not offer separate directional overcurrent protection for each line coming into the distribution station.

Fortunately, the relay has flexible logic available that not only includes typical digital logic, but also has the ability to use analog values measured from each voltage and current input. With analog

values available for use in the logic, it is possible to create custom protection elements that the user can implement for unique applications. Also, the relay allows the user to select which current quantity the built-in time-overcurrent elements will operate on. There are six available time-overcurrent elements that can be set to operate on the following quantities: line current (IX + IW), Breaker 1 current (IW), or Breaker 2 current (IX). Therefore, an overcurrent element can protect the transformer (IX + IW), another overcurrent element can protect an incoming line (IW), and a third overcurrent element can protect the other incoming line (IX).



Analog Input	Function
IW+IX	Line Protection
IW	Circuit Breaker 1 (CB1) protection
IX	Circuit Breaker 2 (CB2) protection
VY	Line protection
VAZ	Synchronism check Circuit Breaker 1
VBZ	Synchronism check Circuit Breaker 2

Fig. 3. Example of a Relay Configuration Provided by the Manufacturer

An analysis of the direction current flow during a fault in each of the three protection zones is defined below. For convention, forward current flow for each breaker is defined as current into the distribution transformer. In other words, a transformer fault will produce forward current flow in both breakers. A line fault will produce reverse current flow in the breaker that will clear the fault.

Fig. 4 shows a fault on the remote station bus or transformer.

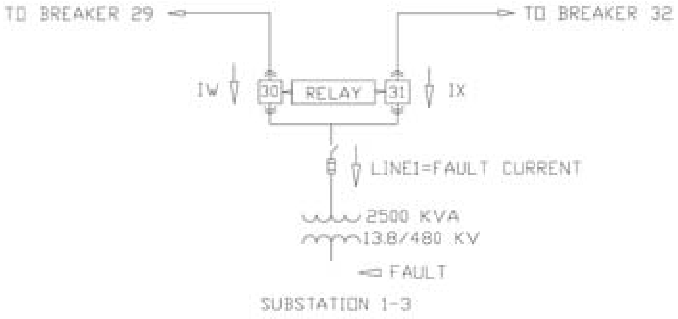


Fig. 4. Fault on Remote Station Bus or Transformer

In this case, the fault current is equal to the relay calculated line current (IW + IX). An overcurrent element (51S1T) will be configured to operate on the line current value and set to coordinate with the fuse for the expected fault current. It will also be set to operate before the feeder breakers on the customer's 13.8 kV bus.

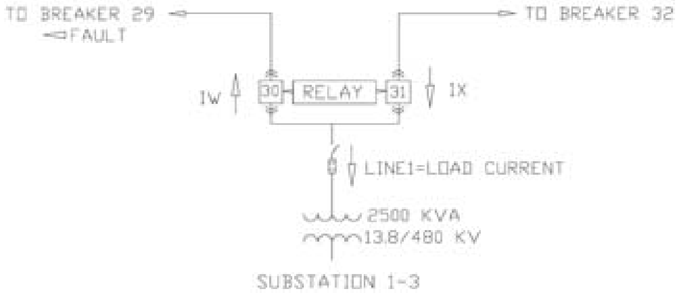


Fig. 5. Fault on Line Protected by Breaker 30

Fig. 5 shows a fault toward Bus 4 in an adjacent line segment.

In this case, current will be in the reverse direction for Breaker 30 but current is in the forward direction for Breaker 31. An overcurrent element (51S4) will be set to send permission on reverse IW fault current and also trip Breaker 30 if permission is received from the remote end.

Fig. 6 shows a fault toward Bus 5 in an adjacent line segment.

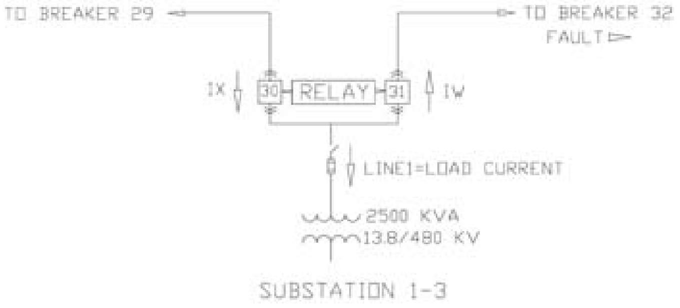


Fig. 6. Fault on Line Protected by Breaker 31

In this case, current will be in the reverse direction for Breaker 31 but current is in the forward direction for Breaker 30. An overcurrent element (51S5) will be set to send permission on reverse IX fault current and will also trip Breaker 31 if permission is received from the remote end.

The overcurrent elements are configured in the standard settings to operate on the appropriate current input value.

Overcurrent element 51S4 is set to operate on the maximum phase current IW. Overcurrent element 51S5 is set to operate on the maximum phase current IX. This essentially sets up two non-directional overcurrent elements that look at the line current each breaker sees in the substation. As mentioned above, non-directional elements will not be enough to securely protect this distribution network.

Since the relay is configured such that the internal directional elements can only be used for transformer protection, an alternative must be developed to directionally control time-overcurrent elements 51S4 and 51S5. The analog quantities and math capabilities of the relay allow the application of traditional phase angle calculations to determine the fault direction of IX and IW. Reference [2] shows a 90-degree connected-phase directional element to be implemented and details the polarizing and operating quantities.

Sonnemann describes the popular 90-degree connected-phase directional element [3]. Table I lists the operating and polarizing quantities of these elements.

TABLE I
INPUTS TO THE 90-DEGREE CONNECTED-PHASE DIRECTIONAL ELEMENT

Phase	Operating Quantity (I_{OP})	Polarizing Quantity (V_{POL})
A	I_A	$V_{POLA} = V_{BC}$
B	I_B	$V_{POLB} = V_{CA}$
C	I_C	$V_{POLC} = V_{AB}$

The following equations represent the torque (TPHASE) calculations for each 90-degree connected-phase directional element:

$$T_A = |V_{BC}| \bullet |I_A| \bullet \cos(\angle V_{BC} - \angle I_A) \qquad (1)$$

$$T_B = |V_{CA}| \bullet |I_B| \bullet \cos(\angle V_{CA} - \angle I_B) \qquad (2)$$

$$T_C = |V_{AB}| \bullet |I_C| \bullet \cos(\angle V_{AB} - \angle I_C) \qquad (3)$$

where:

I_A, I_B, I_C = Phase A, B, and C currents, respectively.
V_A, V_B, V_C = Phase A, B, and C voltages, respectively.
V_{AB}, V_{BC}, V_{CA} = voltage differences $V_A - V_B$, $V_B - V_C$, and $V_C - V_A$, respectively.

Each directional element declares a forward fault condition if the torque sign is positive and a reverse fault condition if the torque sign is negative.

As can be seen from (1)–(3), a torque quantity is generated for each phase using the current and voltage from the other two phases. For a Phase A-to-ground fault, this cross polarization scheme will produce a high torque quantity since Phase A current will be high and the phase-to-phase BC voltage should be unaffected.

Under perfectly balanced voltage and a unity power factor condition, the torque developed for Phase A will be zero. The angle between VBC and IA will be exactly 90 degrees and the cosine of 90 degrees is 0. Therefore, regardless of the magnitude of the VBC voltage or Phase A current, the torque output is zero.

For a forward Phase A-to-ground fault, IA current lags Va voltage, which makes the angle difference between VBC and IA less than 90 degrees. Taking the cosine of an angle less than 90 degrees will produce a positive torque value. For a reverse Phase A-to-ground fault, IA current leads Va voltage, which makes the angle difference between VBC and IA more than 90 degrees. Taking the cosine of an angle greater than 90 degrees will produce a negative torque value. In summary, a positive torque is current in the forward direction; a negative torque is current in the reverse direction.

The cosine operator determines the directionality or sign of the torque value, but the magnitude of voltage and current multiplied together give the torque its magnitude. It can be seen that for a Phase A-to-ground fault, the torque value for Phase A will be much larger than the torque values for the unfaulted phases. In general, the phases involved in the fault will generate the largest torque values.

In an electromechanical scheme with directional torque control, each phase had a dedicated overcurrent element that was controlled by its directional polarizing quantity.

Therefore, if there was a forward Phase A-to-ground fault, only the Phase A relay could operate for the fault because it was the only phase with enough current to spin the induction disc. Even though the induction disc may not have spun on the two unfaulted phase overcurrent relays, the directional torque control may have still determined a direction, and quite possibly, the wrong direction. During a Phase A-to-ground fault, the unfaulted phases, which are still carrying load, are unreliable and cannot be used. Due to this, the torque quantity of the faulted phases must be used in determining the direction of the fault.

In a digital relay, all three phases are available which can sometimes lead to unexpected problems. The overcurrent element being used in the digital relay is a three-phase element, which means it asserts if any phase current becomes greater than the set point. Once that overcurrent element asserts, the faulted phase(s) are not known, therefore, the torque quantity that needs to be used is also not known.

One way to solve the problem is to set up a "fault detector" in the logic. This would require taking the pickup setting of the overcurrent element and putting it into the logic to supervise the torque control. This would operate similar to the electromechanical scheme mentioned earlier where only the torque of the faulted phases is used. The disadvantage of doing this is that the overcurrent pickup setting must now be entered in the logic. It is conceivable that this setting could be forgotten or not updated properly as new settings were issued and lead to undesirable operation of the directional element.

Another option is to compare the torque quantities the relay calculates during the fault and use the largest absolute torque value to determine direction. By using the torque comparison method, no additional fault detectors are needed, and more importantly, the faulted phase(s) will determine the direction of the fault. The logic for winding IW is shown in Fig. 7 (the logic for winding IX is similar).

Notice that lines PROTSEL28–PROTSEL30 match the formulas given for the 90-degree connection in (1)–(3). The manufacturer defines the following analog quantities that are used in this application as follows:

- VBCYM, VCAYM, VABYM: Phase-to-phase filtered instantaneous voltage magnitude in volts secondary
- IAWM, IBWM, ICWM: Terminal W phase-filtered instantaneous current magnitude in amps secondary
- VCBYA, VCAYA, VABYA: Phase-to-phase filtered instantaneous voltage angle in degrees
- IAWA, IBWA, ICWA: Winding (IW) filtered instantaneous current angle in degrees

To add security to the directional element, the operate time of any instantaneous element must be delayed one cycle to allow time for the relay's filtered values to determine the proper fault direction.

This directional element was tested for common type faults in the lab using system impedance values from the customer and operated reliably. However, a close-in three-phase fault can disable the directional element since there is no voltage memory polarization and backup tripping will be needed to clear this type of fault. Roberts and Guzman also detail the possibility of 90-degree directional element misoperation if only a zero-sequence source is located behind the relays [2].

```
PROTSEL24   #PSV10 INDICATES BUS VOLTAGE IS NOT HEALTHY FOR POLARIZATION
PROTSEL25   PSV10 := VABYM < 1 AND VBCYM < 1 AND VCAYM < 1

PROTSEL26   #TORQUE IS POSITIVE IF FAULT IS FORWARD
PROTSEL27   #TORQUE IS NEGATIVE IF FAULT IS REVERSE

PROTSEL28   PMV01 := VBCYM * IAWM * COS(VBCYA - IAXA) #TORQUE A
PROTSEL29   PMV02 := VCAYM * IBWM * COS(VCAYA - IBXA) #TORQUE B
PROTSEL30   PMV03 := VABYM * ICWM * COS(VABYA - ICXA) #TORQUE C

PROTSEL31   #FIND THE ABSOLUTE VALUE OF EACH TORQUE
PROTSEL32   PMV04 := ABS(PMV01)  #|TORQUE A|
PROTSEL33   PMV05 := ABS(PMV02)  #|TORQUE B|
PROTSEL34   PMV06 := ABS(PMV03)  #|TORQUE C|

PROTSEL35   #FIND THE LARGEST ABSOLUTE TORQUE
PROTSEL36   PSV04 := PMV04 >= PMV05 AND PMV04 >= PMV06 #|TORQUE A| IS LARGEST
PROTSEL37   PSV05 := PMV05 >= PMV04 AND PMV05 >= PMV06 #|TORQUE B| IS LARGEST
PROTSEL38   PSV06 := PMV06 >= PMV04 AND PMV06 >= PMV05 #|TORQUE C| IS LARGEST

PROTSEL39   #DETERMINE IF THE LARGEST |TORQUE| IS NEGATIVE
PROTSEL40   PSV07 := PMV01 < 0 AND PSV04 #TORQUE A IS NEGATIVE AND LARGEST
PROTSEL41   PSV08 := PMV02 < 0 AND PSV05 #TORQUE B IS NEGATIVE AND LARGEST
PROTSEL42   PSV09 := PMV03 < 0 AND PSV06 #TORQUE C IS NEGATIVE AND LARGEST

PROTSEL43   #IF PSV11 ASSERTS, THE LARGEST |TORQUE| IS NEGATIVE
PROTSEL44   PSV11 := (PSV07 OR PSV08 OR PSV09) AND NOT PSV10

PROTSEL45   #ADD A DEFINITE TIME DELAY TO THE OC ELEMENT
PROTSEL46   PCT01IN := 51S4
PROTSEL47   PCT01PU:= 1 #ADD A ONE CYCLE DELAY

PROTSEL45   PSV02 := PCT01Q AND PSV11 #FAULT DETECTED IN THE REVERSE DIRECTION
```

Fig. 7. Directional Element Logic

In this distribution system, however, it is highly unlikely that a zero-sequence-only source could become available. Also, for a very high, resistive phase-to-ground fault, the largest torque quantity may not be on the faulted phase. However, this type of fault would be very difficult to detect with traditional overcurrent elements and is not considered a problem in this application since only phase overcurrent elements are being used. Sensitive ground overcurrent elements would require additional design and testing.

As can be seen, the performance of any directional element must be evaluated before applying it to a certain system. In this system and scheme, the shortcomings of the element should not affect the reliability or security of the scheme.

However, in another system or another scheme, this element may be deemed unacceptable for use.

VI. IMPLEMENTATION

From the logic in Fig. 7, it can be seen that PSV02 is the reverse fault detected bit. When this bit is combined with a permissive signal supplied by GOOSE messaging from adjacent relays, the breaker will trip. PSV02 is also used to generate GOOSE messages to be sent to the relays in the loop multicast group as a permissive to trip in the POTT scheme.

Fig. 8 (in part 2) shows how the whole scheme works.

For the fault in Fig. 8, the objective is to open Breakers 15 and 16 to isolate the fault. When Breaker 4 sees fault current, the backup time-overcurrent setting is picked up and begins timing. Breaker 12 is not sending a GOOSE message to trip Breaker 4 because the fault current is in the forward direction, not the reverse as defined earlier. Through GOOSE messaging, Substation 3-1 is indicating a through fault and Breaker 13 is telling Breaker 14 it's got a reverse fault current and is looking for permission to trip. Substation 3-2 is indicating a through fault, and Breaker 14 is not sending a GOOSE message to Breaker 13 to trip because the current is in the forward direction. Breaker 15 is indicating a reverse direction fault and is sending permission to Breaker 16.

See the May issue for Part II