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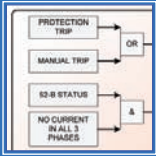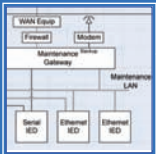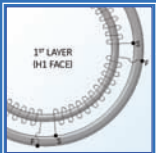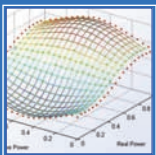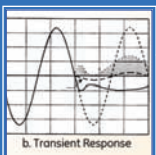
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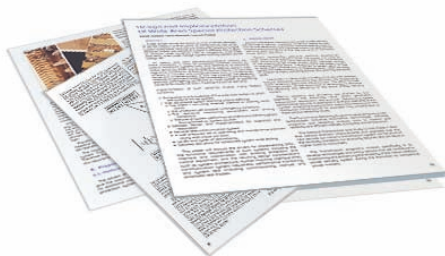
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Innovative Distribution Feeder Protection and Control Schemes Using New Capabilities of Microprocessor Relays

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1. Abstract

Currently distribution feeder protection and control (P&C) schemes are designed using previous generation of the microprocessor relays, electromechanical switches, and separate annunciation and metering panels. The traditional design involves significant wiring and associated costs. Recent advancements in microprocessor relaying technology provide new features, which can replicate functionalities of conventional switches and annunciation & metering interfaces. Utilization of these new features in the modern relays can result in development of cost effective P&C schemes with significantly less wiring requirements.

This paper describes development of an innovative redundant protection and control schemes utilizing the state of the art features offered by the new microprocessor relays for distribution feeder application for one of the major utilities in the United States.

In the process of designing and implementing this new distribution P&C schemes, there were numerous challenges. Special consideration and efforts were extended to comply with the utility's philosophies in relay redundancy, reclosing practices, underfrequency load shedding, overfrequency restoration and protection against "single phasing" conditions in the fused bank applications.

The paper also discusses the operational experiences gained from the feeder installations employing this scheme, which validates the merits in the engineering approach as well as design and implementation.

2. Introduction

Modern economics are becoming increasingly dependent on reliable and secure electricity services and enforcing utilities to upgrade their distribution installations. The growing need for enhanced substation automation and integration system demands from utilities to renovate their distribution protection, control and automation schemes. Over the last decade, utility engineers have understood the benefits of digital multifunctional protective relays and extensively utilized those relays along with traditional switches, annunciation panels and panel board meters in new installations and in retrofits.

The technology advancement and better understanding of utility's growing requirements by relay manufactures led to development of the new generation microprocessor relays offering new elements and functionalities in the relay box.

These new elements/functions provide additional options to a P&C engineer in developing a fully integrated protection and control scheme.

The modern relay technology advancement and new reality of the deregulated energy market have set the stages for a step forward in substation integration and automation at PG&E. In line with this, the decision to develop a new universal Integrated Protection And Control (IPAC) standard for distribution feeders has become an important part of the distribution system renovation plan. The main business and technological goals of the IPAC standard for distribution feeders are summarized below:

- the reduction of the capital, maintenance and operating expenditures

- the need to improve system reliability and at the same time to decrease the service downtime for greater customer's satisfaction

- the need for breaker and protection & control systems monitoring. Use of the information stored in the relay for abnormal situations detection, systems troubleshooting and preventive maintenance

- the operating requirements for local and remote (via SCADA or EMS systems) monitoring, and trending of the steady state conditions such as system loads and voltages

- the engineering requirement for capturing the system currents, voltages and frequency waveforms during power system transient events. Non-volatile storage of this information in the convenient format for further analysis

- the requirement to increase the number of the digital and analog SCADA points collected from the IPAC system in order to decrease the field personnel workload

- the requirement to decrease the cost and at the same time to improve reliability of the SCADA system, which is associated with the reduction of the number of protective relays used, elimination of RTU's analogue transducers & digital I/Os, and elimination of the vendor specific protocol conversion equipment

3. System and Operations Requirements of IPAC Standard Scheme

The new IPAC scheme must comply with many requirements

established by the various utility services and departments. These requirements are based on various operational practices, engineering solutions and field experience. The summary of these requirements is listed below:

3.1 Set-A and Set-B Protection Relays

PG&E policy in regards to feeder protection requires the use of two multifunctional relays namely Set-A and Set-B, manufactured by two different relay vendors. The main reason for this requirement is to maintain the high level of the reliability and to reduce dependence of the overall IPAC scheme to a single manufacturer.

3.2 Redundant Protection

Both relays must include the basic protection functions in order to provide the sufficient redundancy in protective functions and reliable fault clearing of the most common types of the faults. These basic protection functions are as follows:

a. phase instantaneous (50P) and time overcurrent elements (51P) with optional directional supervision (67P)
b. residual ground instantaneous (50G) and time overcurrent elements (51G) with optional directional supervision
c. phase overvoltage (59) and undervoltage elements (27)

The directional supervision of the above mentioned elements is required for fault direction discrimination and it is normally applicable for the feeders connected to generation facilities.

3.3 Enhanced Protection in Set-A Relay

As per utility regulations and system stability requirements, SET-A is equipped with additional protection and automatic restoration functions. These functions are listed below:

a. automatic reclosing with variable number of shots, "reclose stall", and "stall removal" capabilities replicates the functionality of the existing utility standard recloser

b. underfrequency Protection and Automatic Frequency System Restoration. These features are aimed to comply with Under Frequency Load Shedding (UFLS) and automatic service restoration schemes. The typical PG&E UFLS scheme is implemented inside the dedicated stand-alone frequency relay and presents the limited capability of setting the specific frequency levels operation and restoration time delays for the different feeders. Another disadvantage of the single frequency relay is a loss of function availability during maintenance and relay testing. The new distributed UFLS design is implemented independently in each feeder relay of the substation and allows for individual setting of the scheme parameters for each feeder. At the same time no separate frequency relay is required and the operation of UFLS is independent of the single relay failure

c. Breaker Failure Protection (BFP). According to PG&E

protection requirements for distribution breakers, BFP is applied in a switchgear configuration only. The primary reason is that faults inside the switchgear where the space is very limited can cause substantial damage under breaker failure conditions. The switchgears are usually installed in "indoor" stations, where faults coupled with failed breakers can cause severe damage to the whole station. Switchgears are also being proposed and tested for "outdoor" stations. In some instances BPF may also be recommended and installed for open switchyard breakers depending on the breaker failure consequences

d. Negative Sequence Overvoltage: PG&E standardizes the use of this function in the substations equipped with the fused distribution transformers. The blown fuse of the power transformer can cause the supply of the high level of the negative sequence voltage to the distribution system. The voltage unbalance can cause the severe overheating to the motor loads and tertiary windings of the power transformers. Thus the feeders exposed to the relatively high level of the negative sequence voltage of more than 14% are disconnected within 7 seconds per PG&E criteria. Traditionally each fused transformer is equipped with a single voltage unbalance relay. The new voltage unbalance scheme design allows to either integrate the existing voltage unbalance relay or to use the negative sequence overvoltage function of SET-A relay for each feeder, depending on the station configuration and availability of an existing voltage unbalance relay

e. Direct Transfer Tripping: Interconnection of a distributed generation (DG) to the distribution feeder may require a transfer trip scheme. The IPAC scheme for distribution feeder should be capable to send a direct transfer trip command to a DG facility in case of the feeder protection tripping. This function should be supervised by the dedicated cut in/cut out virtual switch for enabling/disabling of this function locally and remotely in response to DG operational condition

f. "Live Line" Blocking of Close & Reclose: The automatic reclosing and manual closing of the feeder with connected DG on it must be supervised by the line voltage while the feeder breaker is open. The feeder breaker closing will be blocked as long as line side potential is present

3.4 Enhanced Control in Set-A Relay

As per IPAC scheme requirements, the SET-A relay should provide local control capabilities and status indications for the following elements and features;

a. Breaker manual trip and close commands

b. Local/Remote control selector switch

c. Ground Relay and Sensitive Ground Relay (if applicable). Cut in/Cut out. According to PG&E's switching practice the Ground Relay must be cut out during the switching operation of a normally "radial" feeder when the

switching results in a "paralleling" of different sources (or different transformers). This is to avoid ground relays maloperation due to excessive loading unbalances that can occur during the parallel operation. Once the parallel feeder is opened at one end, all ground relays are cut in

d. Recloser Cut in /Cut out. Reclosing functions must be disabled during breaker maintenance

e. SET-A and SET-B Cut in/Cut out. Relay is always cut out for relay maintenance and testing. The relay in cut-out mode maintains the complete functionality, but isolates the tripping and other important output circuits from the scheme. This arrangement allows conducting the relay checks while feeder is in service. The operation of these switches can be done only locally by operators or technicians

f. setting group selector switch. In many instances, a breaker may be used as a substitute for other breakers. In such cases, alternate relay settings are often required. Instead of having to adjust the relay settings manually, it is possible to switch the new setting group with predetermined setpoints suitable for the new application. This operation helps to save considerable time and efforts in setting the relay and consequent new setpoints verification

g. front panel alarms and status indications. Local alarms, status indicators, and targets have always existed inside the stations. In the new implementation of the switches, the switch position is indicated by the dedicated front panel LED versus the physical orientation of the switch handle in the mechanical switches applications. Local alarms and indicators are checked and recorded by the operators as soon as the operator enters the station. In many cases, remotely can be provided only per-group alarm indication, or sometimes single station alarm. For detailed alarm information the operator will have to visit the station and check the local annunciation. The new IPAC scheme provides very comprehensive system status information helping to promptly locate the problem and restore the service

3.5 Communication Interface Requirement

a. SET- B provides the communication interface for the remote controls via SCADA. PG&E primary reason for having one set for local control and another set for remote control via SCADA is "demarcation". This demarcation arrangement is required in order to simplify system troubleshooting, maintenance and operations

b. Remote control of Set-A functions is executed via SCADA-Set-B communication link and Set-A - Set-B hardwired binary inputs-outputs links

3.6 SET-A and SET-B Relays Synchronous Separation

The status of the switches and setting group selectors inside

SET-A and SET-B relays must operate synchronously and must be properly coordinated in case of the relay failure, testing, or cycling of the relay DC control power. The consistency of the SET-A and SET-B virtual switches must be supervised by the appropriate alarm.

3.7 Equipment Integrity and Maintenance

Set-A provides equipment integrity detection and maintenance alarms such as:

a. slow breaker operation

b. trip circuitry failure alarm

c. breaker contact wearing monitoring

d. VT Fuse Failure detection

This information presents a reliable indication for equipment problems and provides the valuable information for optimum maintenance scheduling.

3.8 Multi-level Set Point Templates

The development of the multi-level setpoints schedules templates. The amount of the relay setpoint entries required for the standard application must be limited to the number, which utility planners are normally dealt with. So the basic level template is required to be developed to address the needs of the planners. For non-standard applications the comprehensive template is required. The comprehensive template must have provision for the simple activation of the optional functions and elements such as breaker failure protection, directional overcurrent protection, direct transfer trip option, etc.

3.9 Metering and Recording Requirements

Metering and recording requirements. PG&E requires to have the following data available locally and remotely via SCADA:

a. per phase Load Currents and Bus Voltages. Momentary values and time trend records

b. 3 Phase Real and Reactive Power. The momentary values of these parameters are used for operating purposes

c. one Phase Line Voltage and live line indication while breaker is open. This parameter is required in the application with the generation facility

d. per phase Maximum Demand Current

e. breaker maintenance information such as operations counter, contacts wear estimate data

f. time stamped events recorder

g. fault events oscillography capable of capturing waveforms of the multiple events and storing the records of these events in the non-volatile memory

This information can address the needs of the various utility subdivisions such as operations, system planning, protection engineering, maintenance department, billing department and

so on. In the following section of the paper, capabilities of new generation microprocessor relays, which will be used in the development of IPAC standard in align with the above mentioned system and operations requirements, are described.

4. Capabilities of The New Generation of Microprocessor Relays

The previous generation of distribution feeder protection and control package provided a reasonable level of the protection and control integration. However almost all of the supplementary functions such as metering, cut-in/cut-outs, switches, breaker controls, indication lights and SCADA interface were implemented using the traditional devices and conventional selector switches. The example of the previous generation feeder panel is presented in Figure 1.
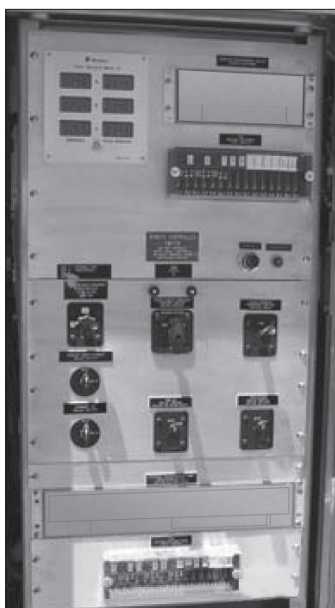

Fig 1.
Existing Standard Feeder Protection and Control Panel.

The technological progress and better understanding of customer's growing requirements by relay vendors led to the development of the innovative relay functionality integrated into one box. These new elements can contribute to the high level of the scheme customization and assist in developing a universal protection and control schemes.

The functionality review of the new elements is presented in this section.

Flexible Programming
The relay is equipped with the universal PLC-style programming tool, which can create the logical sequences required by any application. The logical operators, programmable timers, counters, latches, binary I/O and all the operands internally generated by the relay functions can be used as logic equation entries. A system of sequential operations allows any combination of specified operands to be assigned as inputs to specified operators to create an output. The specially designed logic editor presents a convenient way to compose the logic equations and to inspect the accuracy and the compliance to logic equation rules.

Flexible Protection Elements
These elements present universal comparators that can be used to monitor any analog actual value measured or calculated by the relay or a net difference of any two analog actual values of the same type. The effective operating signal could be treated as a signed number or its absolute value could be used as per user's choice. The element can be programmed to respond either to a signal level or to a rate-of-change (delta) over a pre-defined period of time. The output operand is asserted when the operating signal is higher than a threshold or lower than a threshold as defined per user's choice. Applications could include: positive/negative sequence overcurrent, negative sequence overvoltage, overpower, power factor, temperature differential, frequency rate-of-change etc.

User Programmable Push Buttons (UPPB)
Relay's Faceplate offers user programmable pushbuttons, which are intended to replace the traditional electromechanical switches and can be configured to replicate different types of switches. Each pushbutton can be configured as latched or self-reset.

It can provide the functionality allowing configuring the UPPB in the breaker control application required 2-step breaker control (Select-Before-Operate). In addition the configurable pushbutton LED and front panel display "smart" messaging accomplish the replication of the SCADA based secure breaker control. UPPB also provides the capability of the remote pushbutton control. Separate blocking of the UPPB remote and local controls supports the local/remote control selection.

Another UPPB application utilized in IPAC scheme provides the local and remote single pushbutton execution of the pulse-set/pulse-reset command; for example CUT-IN/CUT-OUT virtual switch. The detailed description of the UPPB can be found in the next section. The UPPB can be easily labeled for added clarity of functionality.

IPAC scheme pushbutton designation is presented in Figure 2
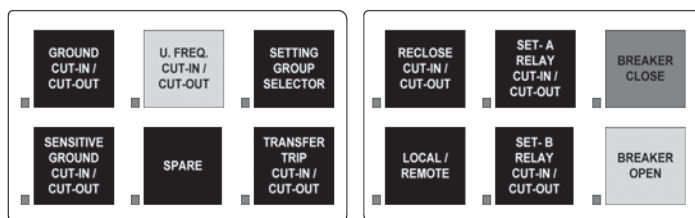
Fig 2.
User Programmable Pushbuttons Designation.

User Programmable LEDs
Relay's front panel is equipped with multiple LEDs which are typically used to provide the annunciation and indications of the functions included in the relay. Any LED can be freely assigned to any one of the operands generated by the relay internal functions or binary I/O's. These LED can conveniently replace the traditional panel stand-alone indication lights and annunciation devices. The LED can be configured as latched or self-reset. Additionally the LED blinking can be implemented using simple logic. These features compliment the complete replication of the typical annunciation panel functionality. The user programmable LED's can be easily labeled for clear

indication of the assigned function.

IPAC scheme user programmable LED's designation is presented in Figure 3.

User Programmable Non Volatile Latches
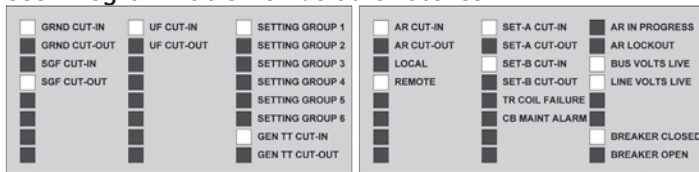
Fig 3.
User Programmable LED's Designation.

Virtual non-volatile latches provide two maintained logical states; set (1) and reset (0) and can be driven to these states by applying any of the operands generated in the relay. The maintained state of the latch is stored in the non-volatile memory and will be restored upon relay rebooting during control power cycling events. In order to sustain the state of the virtual latch even during no control power situations the latch can be assigned to drive the special bi-stable relay outputs. This concept is typically used for the logical implementation of the cut-in/cut-out switches, lockout relays or some other situations when the status of the latching function must be maintained even when the relay control power is down.

Because of the virtual nature of the latch it might be a case when both, the "set" and the "reset" commands are active at the same time. Hence the latch has an option to be configured as a "set" or "reset" dominant depending on the application requirements.

Configurable Selector Switch

Seven-position virtual selector switch is intended to replicate the mechanical counterpart.

The digital technology allows for enhancements in functionality and makes it universal.

The element provides for two control inputs. The step-up control allows stepping through selector position one step at a time with each pulse of the control input, such as user-programmable pushbutton or any other relay operand. The 3-bit control input allows setting the selector to the position defined by a 3-bit word.

The element allows pre-selecting a new position without applying it. The pre-selected position gets applied either after timeout or upon acknowledgement via separate inputs (user setting). The selector position is stored in non-volatile memory. There are 3 different restoration modes "upon relay reboot" available as settable options;

   a. restoration of the switch position stored in the non-volatile memory.
   b. synchronization of the switch position to the current 3-bit word.
   c. first try to synchronize the switch position to the current 3-bit word, but if this attempt is unsuccessful restore the switch position to the value stored in the non-volatile memory.

The SYNCH/RESTORE mode can be useful in some applications where selector switch is employed to change the setting group in the redundant (2 relays) protection schemes.

Digital Counters

The universal bidirectional digital counters are capable of incrementing and decrementing the number of the stored pulses, starting to count from the preset value. The additional functional inputs can reset the counter to the preset value, block the counter operation, freeze the element at the current count and also provide the freeze removal command. The typical applications of this element are a breaker operations counter and a watt-hour meter.

Digital Timers

The universal digital timers provide the additional capabilities to the relay programmable logic. The wide setting range and possibility to integrate the pickup and drop-out time delays in the same timer provides the multiple applications options to this element.

Configurable contact inputs and contact outputs

The modular design of the relay allows for the selection of the number of the relay physical inputs and outputs per application requirements. Each input can be configured as a logical input to any internal relay function. The wide range of the input operational thresholds provides additional universality to this element.

Contact outputs can be assigned to respond to any generated inside the relay operand.

Various types of the contact outputs address the requirements of the different applications such as fast operation, high interrupting capability, use of the normally open or normally closed contacts, bi-stable relays, integrity supervision of the control circuits and trip current monitoring.

Fig 4.
New Feeder Protection and Control Panel Layout.

All the above mentioned elements plus some others such as universal analog inputs and outputs, resistance temperature detector (RTD) inputs, user programmable displays provide the new system design solutions and allow for almost complete elimination of the stand-alone panel devices.

The layout of the feeder panel utilizing many of the innovative relay elements is presented in Figure 4.

front panel pushbutton or remotely via the SCADA, SET B communication link and SET-B, SET-A hardwired inputs/outputs interface. The simplified block diagram of CI-CO virtual switch is presented in Figure 5.

The local operation of CI-CO switch is implemented as one pushbutton control versus 2 pushbuttons set/reset control. This is to accommodate the maximum number of the virtual switches
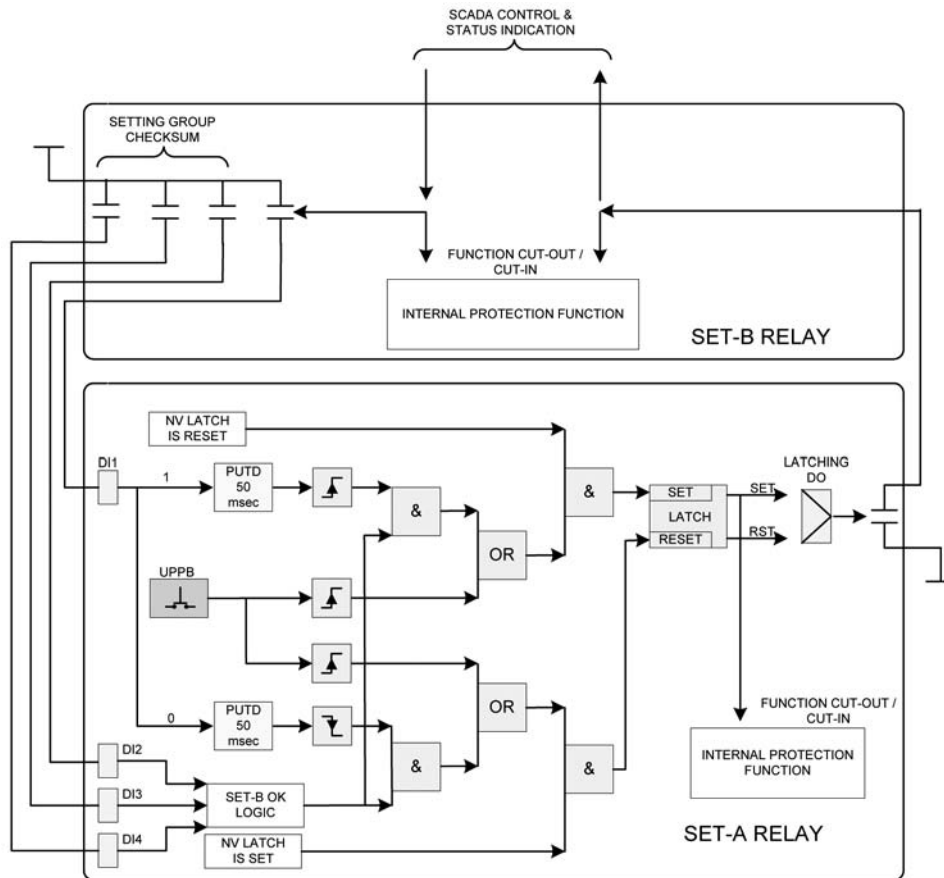
Fig 5.
Generic CUT-IN/CUT-OUT Switch Logic Diagram.

5. Customized Functions For IPAC Scheme

To meet IPAC standard requirements, many control functions were developed innovatively while utilizing the latest features of new generation protective relays.

Some of them are described in this part of the paper.

Cut-In/Cut-Out Switch
In this section the general principals and actual implementation of the Cut-in/Cut-out (CI-CO) switch of the single relay function such as Ground Fault, Underfrequency, Recloser etc, are reviewed.

Consider that the same protection function, which must be cut-in and cut-out, resides in both relays; SET-A and SET-B.

Per application requirements this protection function control must be communicated to both relays, simultaneously, unless one of the relays is out of service. Thus the CI-CO Switch is implemented as a closed loop control.

CI-CO Switch can be controlled locally from SET-A relay's

and assign them to the 12 available user programmable pushbuttons for local control. The self–reset operation mode of this pushbutton is selected versus the maintained mode in order to enable the full remote control capability to the virtual switch. The use of the maintained mode of the pushbutton doesn't allow remote reset of the switch if it were to be set locally.

Remote control is executed via SCADA - SET-B Modbus interface. When command has been received in SET-B relay it will cut-in or cut-out the internal protection function and will issue the latching command to the self-reset contact output of SET-B. The maintained SET-B output is wired to contact input of SET-A and will drive the internal virtual latch inside SET-A. This virtual latch provides the CI-CO signal to the SET-A internal protection function and also it operates the latching output of SET-A, which is wired to SET-B binary input. This signal indicates the status of the CI-CO function in SET-A relay. Inside SET-B relay this signal will be checked with the status of the same function maintained in SET-B and the resulting status or discrepancy alarm will be communicated to remote location via SCADA.

The local control of CI-CO switch is executed in a similar manner. In this case the command is initiated by SET-A user-programmable pushbutton. This command will be communicated to SET-B and will control the SET-A relay internal function. Status of CI-CO switch is indicated on the relay front plate user-programmable LED's panel. The feedback status of the function received from SET-B relay will be compared with CO-CI status in SET-A. In case of mismatch the discrepancy alarm will illuminate the designated front panel LED.

The functionality of this scheme during abnormal protection system conditions, such as relay failure, relay testing, relay power cycling, and relay restoration, have also been taken into consideration.

The following requirements were implemented in the logic in order to handle the abnormal situations:

1. If a relay fails or intentionally taken out of service, the out of service relay status must be communicated to the in-service relay in order to block commands issued by the abnormal relay and prevent accidental operation of the CI-CO function of the in-service relay.

2. If a relay cycles the control power, all the virtual CO-CI switches must be restored to the pre-fault states. All the commands issued by the rebooting relay must be ignored by the in-service relay.

3. Prior to restoration of a relay previously taken out of service for maintenance it is required to match manually all the states of the virtual switches to the states of the corresponding switches of "in-service" relay.

4. The duration of the switching command must be at least 50 milliseconds in order to prevent false operation of the function due to the contacts bouncing. This operation time delay is also utilized in the logic to block the incoming command issued by the partner relay during power loss event.

For example, let us consider the situation when the SET-B relay loses control power for 2 hours. During these 2 hours CI-CO switch of SET-A relay has been switched locally from the "cut-in" to the "cut-out" position.

The pre-failure status of the switch is "cut-in"; virtual non-volatile latches in both SET-A and SET-B relays are in "set" position. Contact output in SET-B, which is wired to SET-A digital input is energized, latching output in SET-A relay is in "set" position and hence the corresponding digital input of SET-B is "hot". When SET-B power drops down it removes relay control power and de-energizes all the relay output contacts, providing the "switch cut-out" command to the corresponding input of SET-A relay, but at the same time it provides the SET-B failure indication to SET-A relay. According to the special requirements execution of the CI-CO command is delayed, so that the "SET-B-failure" signal comes first and blocks execution of the CI-CO command. When power to SET-B has been restored, the relay starts to reboot and will restore all the memorized in the non volatile memory states of the logic parameters and contact outputs. Upon rebooting SET-B relay issues the cut-in command and communicates "SET-B OK" status to SET-A relay. But at the same time "SET-B OK" logic inside SET-A relay declares "SET-B OK" status with 0.5 seconds time delay, thus ignoring the false "CUT IN" command coming from SET-B relay. During these 500 milliseconds SET-B relay will acknowledge the new state of the CI-CO output as "cut-out" and will synchronize SET-B switch status to SET-A.

SET-B Failure is declared in SET-A relay based on the status of 3 SET-A digital inputs directly wired to SET-B outputs. If all 3 inputs are not energized SET-A relay logic assumes that setting group of SET-B relay is undefined or control power is down, hence SET-B relay is declared non operational. The diagram of SET-B FAIL/OK is presented in Figure 6.
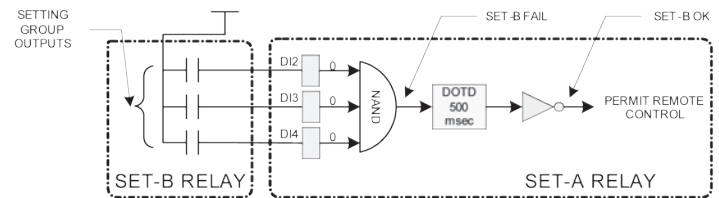

Fig 6.
SET-B FAIL/OK Logic Diagram.

Setting Groups Synchronization
This application requires the use of the multiple setting groups and it is obvious that the setting groups in both relays must be synchronized as long as both relays are in service.
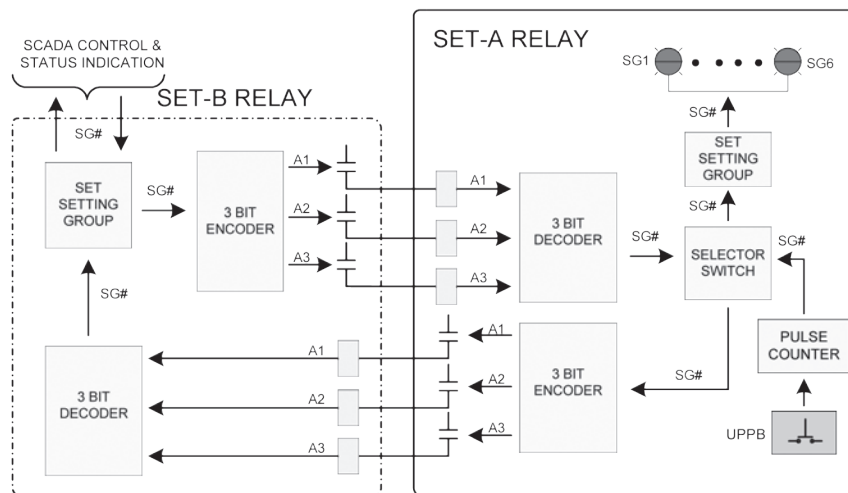

Fig 7.
Setting Group Block Diagram.

Inputs / Outputs Status			Setting Group (SG#)
A1	A2	A3	
ON	OFF	OFF	Setting Group 1
OFF	ON	OFF	Setting Group 2
ON	ON	OFF	Setting Group 3
OFF	OFF	ON	Setting Group 4
ON	OFF	ON	Setting Group 5
OFF	ON	ON	Setting Group 6
OFF	OF	OF	No Change

Fig 8.
Setting Group Encoding Table.

The setting group change can be executed remotely, from SCADA or locally, from front panel pushbutton. The simplified setting group block diagram and the encoding table are presented in Figures 7 and 8 respectively.

Actually the setting group change logic is developed based on the virtual selector switch control element. Let us review the implementation of the setting group control in SET-A relay.

Selector switch element is configured in SET-A relay as a "6 maintained position switch", where each position is used to activate the corresponding setting group in SET-A relay, and also used to transfer the setting group information via 3-bit decoder and a hardwired "output/input" interface to SET-B relay. This 3-bit information is encoded inside SET-B relay and activates the matching setting group in SET-B. Active setting group of SET-A relay is also indicated by front panel user programmable LED's.

There are 2 methods available in IPAC scheme to select the new position of the virtual selector switch and consecutive setting group activation.

* the first method (Local Control) is to press the assigned user programmable pushbutton (UPPB). Number of times that UPPB was pressed with less then 5 second intervals between pulses is interpreted as number of Switch position operations and when 5 seconds of inactivity is expired SELECTOR SWITCH asserts the pre-selected position. In other words if the initial active Setting Group is # 1 and you press UPPB three times with 2 second intervals between operations the Setting Group 4 will become active 9 seconds after the first UPPB operation. All the interim SELECTOR SWITCH positions and the corresponding setting groups will be skipped

* the second method (Remote Control) is to apply a 3 bit external signal from the SET-B relay to SET-A relay. The selector switch position will be changed according to the decoded position number supported by the acknowledgment signal. The acknowledgment must come shortly (10-15 milliseconds) after any 3-bit activity coming out of SET-B relay. In this manner the almost simultaneous setting group change is insured in both relays during the remote setting group control. The acknowledgement signal is formed as any rising or falling edge of any of 3 inputs (3-bit signal). The exception is when all of the signals become "zeros". In this case the setting group in SET-A relay will remain unchanged. The 3-bit control is supervised by status of SET-B relay and will be available only if SET-B relay is operational

The special logic is required to address the selector switch (setting group) behavior during relay power up or power down cycles. When power to the relay is applied or restored after control power loss the relay attempts to synchronize the setting group position to SET-B active group. But if all inputs coming from SET-B's 3-bit outputs are 0, or SET-B relay is not in service, then SET-A will restore the last active setting group memorized in the non-volatile memory of the relay.

Autoreclose and Autorestoration.
Implementation of the application requirements of the autoreclose and frequency restoration logic presented some challenges. Even the comprehensive standard autoreclose function available in the relay couldn't cover all the special features and details, required by the utility's criteria. Use of the internal relay programmable logic elements helped to provide the high level of the autoreclose scheme customization and implement all mandatory and optional scheme requirements.

According to the system requirements automatic breaker closure may be performed due to any of the following system conditions:

* feeder restoration after the transient fault

* restoration after recovery of the system voltage to an acceptable level of balance and magnitude

* restoration after recovery of the system frequency to an acceptable level

The first two conditions are related to the multi-shot autoreclose (AR) function configured and customized in SET-A relay. The third condition is related to the frequency restoration logic, which is custom developed per utility specification and also placed in SET-A relay.

The initiation logic of the AR function is presented in Figure 9. The recloser is initiated each time breaker makes transition from closed to open state (52-B status). There are of course some exceptions (NOT AR TRIPS) for example; when breaker is tripped manually or in response to the underfrequency condition. The utility's approach to declare the AR initiation (breaker open status, except some special conditions) differs from the concept offered by the relay's standard autoreclose scheme. The standard autoreclose initiation is declared when breaker is closed (must condition) and initiation signal has been received.
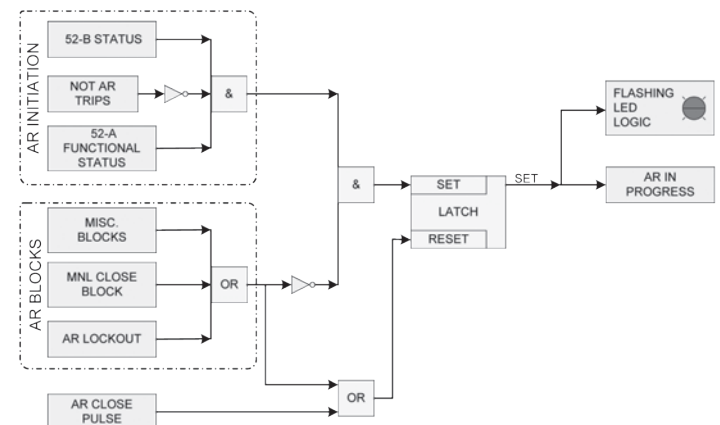

Fig 9.
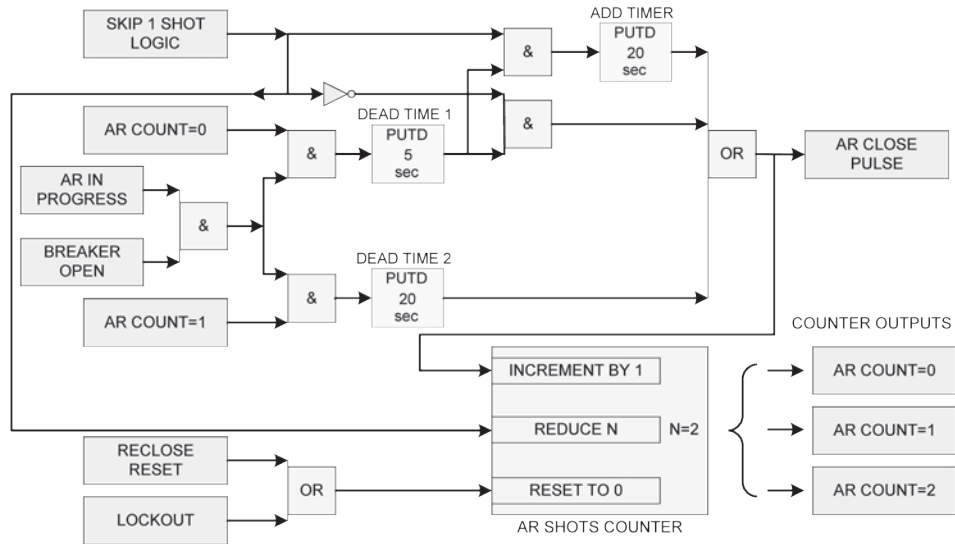*Reclose Initiation Logic Diagram.*

Fig 10.
Reclose Closing Logic Diagram

Thus autoreclose logic requires the functional "breaker closed" state to be defined. This state is implemented in programmable logic. For autoreclose logic, the breaker is declared closed when it is actually closed and 50 milliseconds after 52-a contact changes it's state from closed to open.

Breaker is also declared closed (for autoreclose logic only) whenever breaker is open and previously applied AR stall condition has been removed.

AR initiation will be blocked if the reclose function is locked out, upon a "manual close" command or due to the other miscellaneous blocking functions such external blocking, abnormal voltage, operational cut-out of AR function and a few other conditions.

While reclose is initiated it will seal itself in the "in progress" mode. The flashing front panel LED provides a visual indication of the "AR in progress" status.

"AR in progress" will be reset whenever the AR issues the closing command or the reclose blocking of any kind becomes active. The simplified logic diagram of the AR closing logic is presented in Figure 10.

According to the utility's criteria the recloser should have 2 closing shots with settable (usually 5 and 20 seconds) dead times respectively. For feeders with excessive fault duties the first reclosing shot may be omitted and only one reclose with 25 seconds time delay be executed.

The AR dead time timers will start to count down when the AR function is declared in progress and breaker is open. The active timer is selected based on the AR counter accumulation status.

If the counter accumulation status is equal to 0 then the "DEAD TIME 1" timer which is responsible for the first shot will start counting down. If the counter accumulation is equal to 1, indicating an unsuccessful first reclosing shot then the "DEAD TIME 2" timer which is responsible for the second shot will start counting down.

If the counter accumulation is equal to 2, or in other words counter reaches its maximum accumulation, then AR logic applies the "lockout" and prevents any further AR operation. Maximum accumulation of the counter can be also reached at AR COUNT equal to 1 in the situation with high fault duty, where the first AR shot is skipped. The same signal also reduces the maximum level of the "number of the shots" counter in order to accomplish the adequate functionality of the whole standard reclosing scheme.

If the reclose cycle is successful and the feeder is back in service, the reclose function will "reset" and become available for the new cycle, 65 seconds after the successful breaker closure.

If the reclose cycle is not successful and the breaker remains tripped after the last available shot the reclose function will
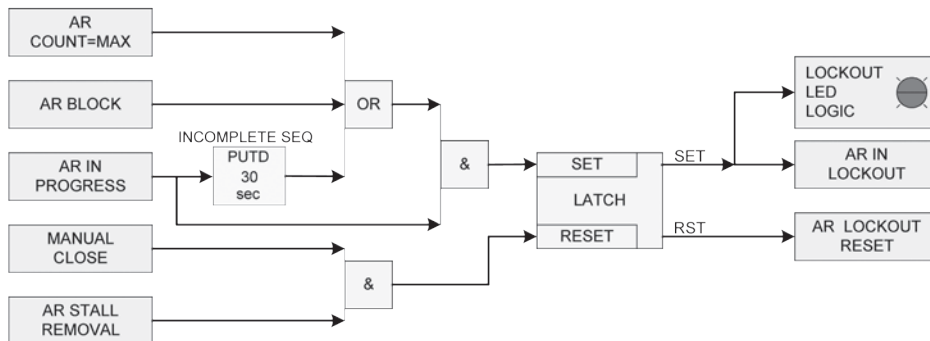

Fig 11.
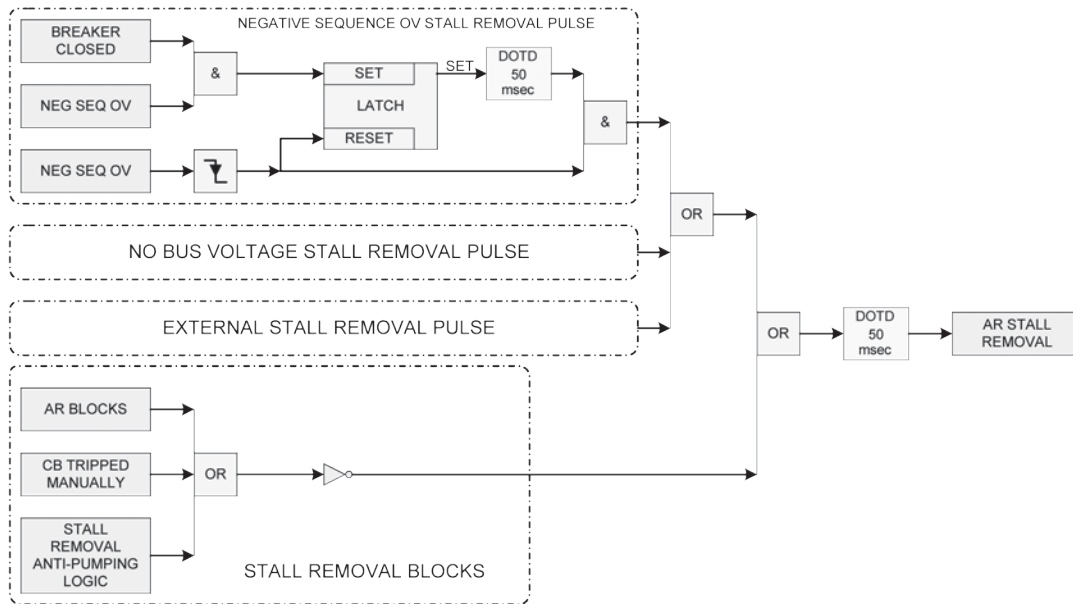*Reclose Lockout Logic Diagram.*

Fig 12.
Reclose Stall Removal Logic Diagram.

go into "lockout" and will remain locked out until the feeder is closed manually. The simplified AR lockout logic is presented in Figure 11.

According to this diagram the AR "lockout" can be applied only during the reclose cycle (Reclose in progress status). It can also be applied when the "reclose" function attempts to proceed to the next shot, due to an unsuccessful "reclose" attempt, where the maximum number of shots has been reached. The AR "lockout" will be applied if the blocking signal of any kind becomes active while reclose is in progress. Another cause for AR "lockout" is the incomplete sequence, when the AR "in progress" status remains active longer than the "DEAD TIME" setting. In our application the incomplete sequence is set to 30 seconds.

There are two methods available to reset an AR "lockout" condition:

- manual close (see Fig 11.)

- lockout reset upon stall removal

According to the utility requirements the developed AR scheme must support the reclose stall feature. This feature must temporary disable the "reclose" function due to some abnormal system conditions such as:

- "no bus voltage" condition, presumably because of the upstream reclosing operation

- negative sequence overvoltage condition, presumably because of the power system loss of any phase situation

When the condition causing the reclose stall has been restored to normal due to successful upstream reclose in case of "no bus voltage" stall or due to high voltage side transformer fuse replacement in case of negative sequence overvoltage stall, then the reclose full cycle will be resumed

Figure 12 demonstrates the simplified logic of the stall removal mechanism. It is very important to ensure that the reclose stall is removed only from the same system condition that it was

applied. The same "apply-remove" logic blocks are presented for all system conditions configured to stall the recloser. The stall removal is inhibited if AR function is blocked or the feeder breaker has been opened manually. The stall removal "anti-pumping" feature provides one time operation in order to prevent multiple "apply-remove" actions due to some unstable system conditions or sensing device failure. The designated logical timer determines the minimum time between 2 consecutive "stall removal" operations.

Overfrequency Automatic Closing

The described feeder protection and control scheme provides an automatic restoration capability after underfrequency tripping events. There are two different overfrequency restoration levels are implemented in the scheme:

- frequency overshoot; this level is developed to address the situations when the frequency is restored to the level well above the rated system frequency of 60Hz. In this case in order to maintain the system load-generation balance a high speed breaker closing is required

- overfrequency restoration; this level is developed to address the situations when the frequency is partially restored
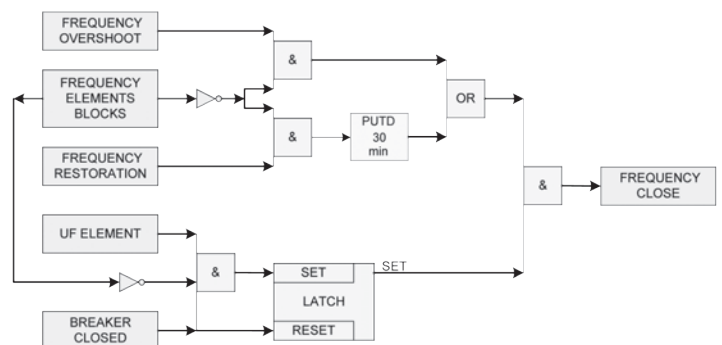

Fig 13.
Overfrequency Automatic Closing Logic Diagram.

to the level slightly below the rated system frequency of 60Hz. In such case, the restoration time delay is in the order of minutes and it is determined by the power system frequency event recovery plan

The simplified logic diagram of the Overfrequency Automatic Closing is presented in Figure 13.

The frequency restoration scheme becomes operational only if it was previously armed by the underfrequency event. The underfrequency arming is supervised by the closed status of the breaker in order to prevent an inadvertent automatic closing of the feeder breaker, which was intentionally left open. All the frequency elements are supervised by the relevant blocks such as relay cut-out status, frequency cut-out status, low voltage condition, etc.

Slow Breaker Maintenance Tool

Based on the utility's request, a "Slow Breaker" detection logic to be used as a breaker maintenance tool, was programmed in the relay and implemented in the scheme.

This tool is intended to verify the main breaker contacts travel time during the breaker "close" and "open" operations and to compare this time to the reference breaker operation times. If the actual operation time exceeds the reference time then the slow breaker condition will be declared and the corresponding alarm is communicated to the local and remote interfaces.

The breaker status is declared open if no current is detected in all 3 phases and the auxiliary breaker contact 52-B is closed.

The breaker status is declared closed if current is detected in all 3 phases and the auxiliary breaker contact 52-A is closed.

This scheme provides the correct results during on-load breaker operation but it is not always reliable for detection of a slow breaker during unloaded feeder breaker operations.

The self-explanatory simplified logic diagram of the slow breaker tool is presented in Figure 14.

6. Conclusions

The new state of the art Integrated Protection And Control (IPAC) design has been developed as a joint effort of the distribution engineers and P&C experts from relay vendors and the Pacific Gas and Electric (PG&E). The IPAC design offers universal and reliable distribution protection and control solution to PG&E with a potential for substantial future cost savings. Additionally, the IPAC design is convenient to operate, useful for preventive maintenance and easy to troubleshoot.

The IPAC design for distribution feeders considered all of PG&E's technical requirements. The successful implementation of IPAC design has established a new utility standard for multiple installations of the switchyard distribution feeders within PG&E.

The key benefits of the innovative IPAC design are listed below:

1. Improved reliability and security as two independent sets of microprocessor relays from two different manufacturers are used.

2. Cost effective solution as many traditional protection and control functions such as Breaker Failure Protection (BFP), and traditional switches, auxiliary relays, metering devices are integrated in the same relay box.

3. More flexibility in relay settings/programming and in selectivity of the feeders to be tripped. Examples:

   a. Implementation of Under Frequency Load Shedding (UFLS) and the Automatic Frequency Recovery Restoration schemes on SET-A relay for each individual feeder as compared to centralized implementation of this scheme in one single relay in traditional design

   b. Implementation of Negative Sequence Overvoltage scheme for detection of single phasing conditions of fused distribution transformers within each relay as compared to centralized implementation of this scheme in one single relay in traditional design
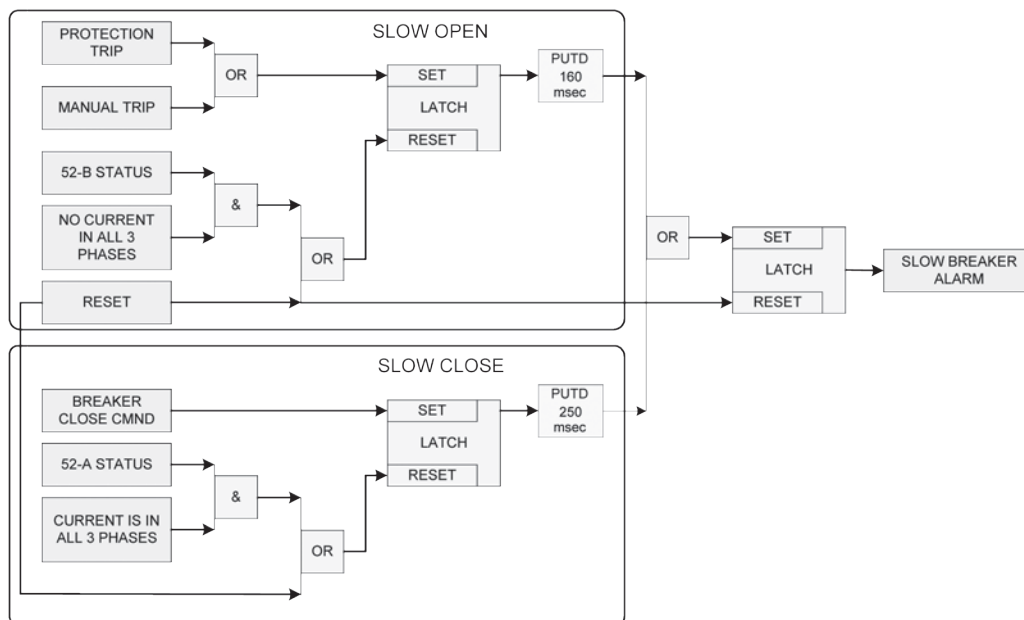

Fig 14.
Slow Breaker Detection Logic Diagram.

c. Provisions for Direct Transfer Trip and Reclose Blocking features. Reclose Blocking function will be installed on every feeder as a standard feature in anticipation of future Distributed Generation (DG) interconnections

d. Development of new monitoring features such as the "Slow Breaker" Maintenance Tool

4. Additional cost savings, as all required data recording, metering, and event information have been implanted within both microprocessor relays with local and remote retrieval capabilities.

5. Standardized solutions such as universal multilevel relay templates to facilitate relay setting calculations and error checking.

Despite the fact that many of the challenges to accomplish harmonious functionality of all features between two independent sets of relays have been successfully resolved, new challenges and concerns are recognized as the field experience is gained with the new design. Scheme behavior concerns about issues such as; DC Voltage fluctuations, relay contacts de-bounce timing, and field personnel/operator intervention could be of interest for further investigation and monitoring by utilities and relay manufactures.

Since the successful introduction of this IPAC design, many of the new and retrofit feeder installations have been upgraded to the new standard, and they are successfully operating and providing a reliable and secure service to the thousands of PG&E customers.

7. References

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[4] M. P. Pozzuoli "The Universal Relay. The Engine For Substation Automation" GE Publication GER-3995, 1998

[5] W.C New "Load Shedding, Load Restoration and Generator Protection Using Solid-state and Electromechanical Underfrequency Relays" GE Publication GET-6449

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Improving data throughput on a wireless IED network

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Chattanooga Electric Power Board

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Edison Automation Inc.

1. Abstract

The Chattanooga Electric Power Board (CEPB) is a municipal electric utility, serving the city of Chattanooga, Tennessee, with a service area of 600 square miles and a population of approximately 350,000. The initial 900 MHz radio system was installed by MDS in 1992 as the primary communications medium for CEPB's large SCADA system, which provides extensive monitoring and control capabilities at 25 transmission, and approximately 150 distribution substations along with critical switching devices. The network was comprised of a 6-hop link backbone point-to-point radio system, feeding 6 Multiple Address System (MAS) master radios for substation communications. CEPB's business model emphasizes excellent customer service and zero outages, making the company's supervisory control and data acquisition (SCADA) system a critical component when it comes to meeting these goals with both reactive and proactive measures.

Although the company was satisfied with the performance of its existing PTP-MAS radio system, CEPB was looking to evolve its communications to include an IP data path for end devices. Specifically, CEPB has a project underway to upgrade the RTUs to fully support IP communications end-to-end and then deploy DNP/IP protocol as a replacement for DNP Serial. Increased data speeds and bandwidth supported by the LEDR-iNET upgrade were required to elevate RTU communications beyond the present baud rate. Once fully implemented, SCADA Master – RTU communications will more closely resemble a flat network with significantly increased communication speeds and improved data throughput. From a system maintenance perspective, the ability to interrogate, configure, upgrade and manage all components comprising the entire radio network via the inherent Ethernet connectivity was extremely attractive as a practical method to improve diagnostic and troubleshooting techniques from the desktop, reduce or eliminate site travel time and increase overall productivity. Embedded SNMP traps provide a good snapshot overview of the health and performance of all radio components for casual review, while providing a method to quickly determine any area of the system which may require more in-depth analysis or inspection. New generation components would also further ensure high availability and redundancy of the radio infrastructure.

2. Evolving to support the digital future

When CEPB installed its large radio system in the early 1990s, they made a significant investment in the hardware infrastructure. For example, the existing MAS is comprised of six tower sites strategically located on the geographic boundaries of CEPB's customer service area.

The original analog point-to-point (PTP) backhaul system originated from the utility's control center, emanating to each of the six tower sites where the MAS equipment was located. This provided six distinct areas of radio coverage, designated by unique frequencies and the equipment within those areas. The six communications channels provided by the six MAS sites provided an organized method of polling 170-plus RTUs by the SCADA master.

Microwave Data Systems (MDS) and their full-service partner Edison Automation, worked together with CEPB to upgrade their system while re-using the legacy infrastructure and equipment.

This included:

- replacing the aging licensed system consisting of 960 MHz analog PTP backhaul and 928 MHz digital MAS master equipment and remote radios

- acquiring faster communication speeds with an immediate path to support end-to-end IP-capable equipment (typically RTUs, IEDs, cameras and SCADA master)

- consolidating all radio and network components for single-point management and monitoring of performance

- reusing existing infrastructure (antennas, coax, etc) at all master and remote radio sites

- performing installation, staging, testing and cutover with minimal downtime

The final step was probably the most significant. The existing radio system was operational and supporting full communications for a large SCADA system, therefore, it was imperative that the construction, configuration, testing, and commissioning of the new system occur with minimal interruptions to the existing system.

3. Evolve, Consolidate, Accelerate: The IP Solution

To preserve CEPB's investment in its legacy network and existing infrastructure, existing antennas, coax, and support equipment were retained and retrofitted to the new electronic equipment to provide a stable, operational system without having to make a "forklift" upgrade of the support infrastructure. Components

of the new system include:

- 4 head-end MDS LEDR radios (Figure 1) with routers at the control center, with two LEDR links supporting two independent hops over the same LEDR backhaul link

Fig 1.
The LEDR Digital Radio

- 6 tower sites comprising a redundant LEDR PTP backhaul radio
- 6 MDS iNET Access Points (APs) each with router and network switch (Figure 2)

Fig 2.
MDS iNet 900™

- 170+ remote MDS iNET radios
- PC for remote configuration, control and performance monitoring of all radio equipment through SNMP trap services and remote telnet administration
- firmware in the radio equipment that can be upgraded across the network
- Ethernet network routing, which allows the communications network to better manage bandwidth at each tower and for all remotes associated with the network

CEPB took advantage of replacing an aging analog point-to-point/multiple address system with the new technology offered in digital point-to-point solutions and frequency hopping spread spectrum radios. MDS replaced the analog PTP backhaul system with LEDR radios while the MAS system was replaced with the MDS iNET 900, an unlicensed, frequency hopping spread spectrum radio.

With the IP based radio infrastructure, CEPB has migrated to the new radios via a temporary DNP3 serial connection from the RTU to the MDS iNET radio at the substation. The iNET radio came equipped with both a serial and Ethernet port to make future migration easier. At the time of migration to an IP end-to-end system, only reprogramming of the iNET radio to activate the Ethernet port will be required. From the iNET to the access point, through the LEDR radios to the headend router, DNP3/IP can be supported. Currently at the headend, the data must be converted back to DNP3 serial for interfacing with the

SCADA Master front-end-processor (FEP). RTU components and the SCADA master are currently being upgraded to provide full Ethernet connectivity. Once this is accomplished within the next 2-3 years, end-to-end IP will be fully operational in the CEPB network.

With the new MDS LEDR-iNET radio system and MDS NETview MS™, CEPB can now monitor and manage the entire radio system from the desktop. Full-featured SNMP traps provide a real-time overview of system health and performance while remote configuration and firmware updates are fully supported at the desktop--often eliminating road trips to the site for these activities.

4. Greater throughput, bandwidth, and real-time monitoring

Unlicensed spread spectrum allows higher speeds and faster data rates, which coupled with the end-to-end IP connectivity offered by the MDS iNETs, were enticing elements of the upgrade design.

RTU/substation data capacity (bandwidth) of the system was increased by virtue of the new LEDR-iNET radio system, to prepare for future needs required for DNP/IP communications. Once the serial-to-IP conversion presently used is eliminated, the end-to-end transit should be virtually transparent with no latency. With an approximate cost of $450k to establish an IP infrastructure to serve 170 locations, and $3,500 per location, CEPB is convinced this migration is the most cost-effective way to replace legacy equipment and gain many benefits including increased data bandwidth and faster RTU communication response.

The new MDS iNET/LEDR network provides the primary communication medium for a new fault isolation - automation scheme on CEPB's 46kV subtransmission system. CEPB has developed automated software running on the SCADA master servers, to automatically detect faults, identify the path of the fault, implement automatic sectionalization and load recovery. Pole-mounted PT/CT sensors are used to detect fault currents through specific nodes on the circuit, thus identifying the passage – or lack of – of fault current at that node. The goal of the automated process is to reduce customer outages for improved SAIDI/SAIFI, while automatically identifying and isolating suspected faulted line segments between controllable nodes (motor-operated switches) on the circuit.

CEPB targeted deployment of the automated schemes on its 46kV subtransmission system to gain significant reduction of the total customers impacted by a permanent outage. The 46kV automated isolation/recovery process, typically accomplishes fault isolation and load recovery within 1-2 minutes after feeder lockout, compared to 10-15 minutes typical with system operator involvement. The automated system logic is designed to closely mimic standard operating procedures, operations and decisions normally executed by system operators, only much faster. Logic is built into the automation scheme computer code to incorporate and fully support all safety requirements including lockout/tagout procedures, device clearances, equipment availability and/or malfunction and other business

Improving data throughput on a wireless IED network

processes applied to the electrical system. From a business case standpoint, the cost/benefit quickly adds up by taking the minutes of outage time saved, times the number of incidents per year, times the number of customers per feeder. Currently 20 46kV circuits are automated, with a plan to do 20 per year for the next 2 to 3 years.

Major benefits realized from the 46kV Automation Scheme have been significant reductions in the total number of customers affected by a permanent outage on 46kV subtransmission feeders. Typical customer counts on any given 46kV circuit can range from a low of 2000 customers to a high of 8000 – 10000 customers. The automation logic is implemented such that once the faulted circuit segment has been identified and isolated, the majority of the remaining unfaulted circuit can be recovered via the original source feed or other alternate feeds. Oftentimes, the entire customer load is recoverable with only an unloaded portion of the circuit isolated as faulted. The resolution of recoverable circuit segments – i.e. customer load – is enhanced by the addition of remotely controlled motor-operated switches at key nodes in the circuit. The ability to either totally isolate historically problematic circuit segments is possible or the ability to provide multiple alternate feeds into the affected area is greatly enhanced, ultimately increasing the chances of maximum load recovery.

Historically, system conditions are most affected by prevalent thunderstorms of the spring and fall seasons which tend to be the most violent and destructive. It is in these times of system disruptions that the automation schemes provide a deterministic solution to fault isolation – load recovery "in the background" as the storm rages around everything else. Since the automation scheme closely follows normal manual switching of the circuits, safety is reinforced and maintained throughout. With approximately 20 circuits thus far having such automated recovery abilities, the potential numbers of customers that can be quickly restored from an outage increases dramatically.

5. Seamless transition to new system

All of the equipment for the new system was configured, staged, and made operational on a test bench prior to the actual installation. In the end, the actual cutover occurred one channel (LEDR/AP frequency) at a time while the legacy PTP/MAS equipment was left intact with the new LEDR/AP equipment installed side-by-side.

6. Lessons learned

The most significant lesson to be learned from CEPB's conversion/upgrade product was the necessity of detailed and exact planning for both the physical conversion and the required RF changes. Other lessons:

- ensure AP-iNET RSSI coverage is robust for one watt unlicensed spread spectrum radio system before replacing five watt MAS system

- remember that environmental conditions change. Be sure to check and recheck antenna height near obstructions (buildings, trees, terrain) for remote sites

- complete intermodulation studies to ensure adjacent channel and/or intermod interference won't diminish remote RSSI/SNR characteristics

- develop a flexible, robust, network/IP-addressing scheme before deployment to permit separation and management of numerous radios and other IP equipment

7. The results: One year later

CEPB has successfully operated its LEDR/MDS iNET system for over one year. They have the newest radio technology available today and an IP data path from their substation to the Operations Center for various IP devices in the future. CEPB is enjoying the ease of single-point management and performance monitoring of all radio and network equipment, they can perform self-documentation of system performance, errors, or problems.

Most important: CEPB has maintained and even enhanced its excellent customer service and record for zero unplanned outages.

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Secure Substation Automation for Operations & Maintenance

Byron Flynn
GE Energy

1. Abstract

Today's Cyber Security requirements have created a need to redesign the Station Automation Architectures to provide secure access for Operations and Maintenance Systems and Personnel. This paper will review several architectures being used and planned by utilities today.

Several real world architectures will be reviewed including

1. Serial SCADA & Dial-up Maintenance,

2. Serial SCADA & LAN based Maintenance,

3. Combined LAN for SCADA and Maintenance and;

4. Separate SCADA WAN/LAN and Maintenance WAN/LAN.

Each architecture will include various methods of User authentication and secure access to various station IEDs including relays, meters, RTUs, PLCs and station servers. This will include configuration access, maintenance access, and manual and automatic data retrieval of fault data.

2. Background

In August of 2003, NERC issued the Urgent Action Cyber Security Standard 1200. This standard was set to expire in August of 2005 but was given a 1 year extension. A new standard originally called Standard 1300 and now named the NERC Critical Infrastructure Protection (CIP) Cyber Security Standard.

As of January 16, 2006, the current version of the document is Draft 4 [1]. The section headings are:

> CIP-002 Critical Cyber Asset Identification
>
> CIP-003 Security Management Controls
>
> CIP-004 Personnel and Training
>
> CIP-005 Electronic Security Perimeter(s)
>
> CIP-006 Physical Security
>
> CIP-007 Systems Security Management
>
> CIP-008 Incident Reporting and Response Planning
>
> CIP-009 Recovery Plans for Critical Cyber Assets

According to NERC:

Bulk Electric Systems are "defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." [2]

Critical Assets are those "facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System." [3]

Critical Cyber Assets are "Programmable electronic devices and communication networks including hardware, software, and data." [4] "Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a Control Center; or,

R3.3. The Cyber Asset is dial-up accessible." [5]

3. Definitions [6]

3.1 Certificate Authority

A certificate authority or certification authority (CA) is an entity which issues digital certificates. In cryptography, a public key certificate (or identity certificate) is a certificate which uses a digital signature to bind together a public key with an identity – information such as the name of a person or an organization, their address, and so forth. The certificate can be used to verify that a public key belongs to an individual.

CHAP
Challenge Handshake Authentication Protocol is an access control protocol for dialing into a network that provides a moderate degree of security. CHAP uses encryption of random values with the client's password for authentication.

HTTPS
Hyper Text Transport Protocol Secure is a secure version of HTTP, the communication protocol of the World Wide Web, invented by Netscape Communications Corporation to provide authentication and encrypted communication. Instead of using plain text socket communication, HTTPS encrypts the session data using either a version of the SSL (Secure Socket Layer) protocol or the TLS (Transport Layer Security) protocol, thus ensuring reasonable protection from eavesdroppers, and man in the middle attacks.

3.2 Identification Factors

There are generally four Identification Factors that are used for authentication. None of them are entirely foolproof, but in order of least to most secure, they are:

1. What You Know – passwords are widely used to identify a User, but only verify that somebody knows the password.

2. What You Have – digital certificates in the User's computer add more security than a password, and smart cards verify that Users have a physical token in their possession, but either can be stolen.

3. What You Are – biometrics such as fingerprints and iris recognition are more difficult but not impossible to forge.

4. What You Do – dynamic biometrics such as hand writing a signature and voice recognition are the most secure; however, replay attacks can fool the system.

PKI
Public Key Infrastructure is an arrangement that provides for third party vetting of, and vouching for, User identities. It also allows binding of public keys to Users. Public Keys are typically in certificates.

PPP
Point-to-Point Protocol is the most popular method for transporting IP packets over a serial link between the User and the ISP. Developed in 1994 by the IETF, PPP establishes the session between the User's computer and the ISP using its own Link Control Protocol (LCP). PPP supports CHAP authentication.

SSL
Secure Sockets Layer is the primary security protocol used on the Internet. Originally developed by Netscape, it validates the identity of a website and provides an encrypted connection for transactions. SSL uses HTTPS protocol. Use of SSL requires a certificate from a Certificate Authority.

Secure Connection Relay
In Secure Connection Relay, a client outside the security perimeter establishes an SSL connection with a gateway, which then makes an unencrypted TCP connection to another TCP address on the substation LAN and relays traffic between the SSL connection and the TCP connection.

Secure Terminal Server
In Secure Terminal Server, a client outside the security perimeter establishes an SSL connection with a gateway, which then opens a serial port and relays traffic between the SSL connection and the serial port.

Secure Data Concentrator
This capability provides secure SSL encapsulation for any networked SCADA protocol on the concentrator.

TLS
Transport Layer Security and it predecessor are cryptographic protocols which provide secure communications on the Internet. There are slight differences between SSL 3.0 and TLS 1.0, but the protocol remains substantially the same.

T-F A
Two Factor Authentication requires two authentication factors before accessing a system and is considered strong authentication.
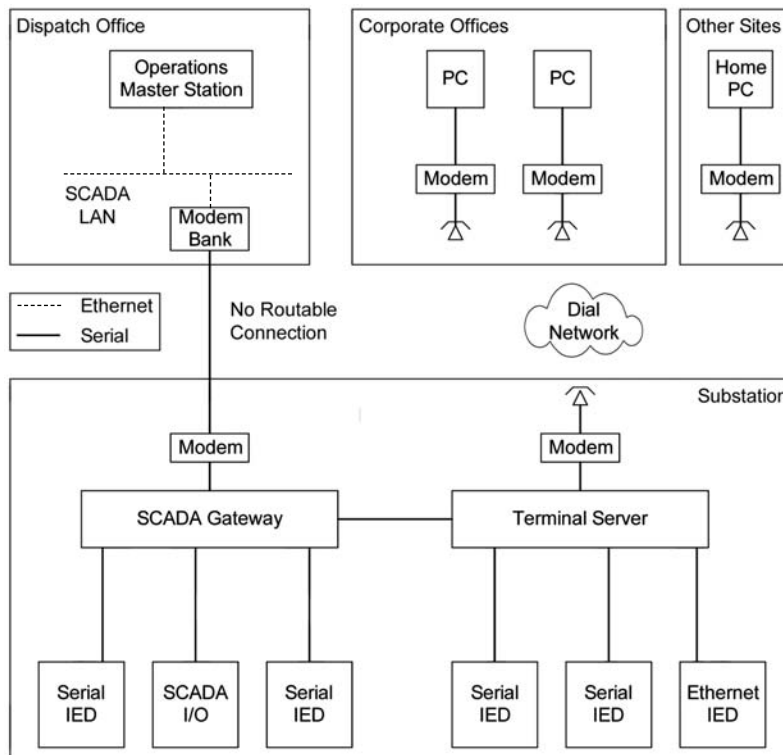

Fig 1.
Existing Architecture.

4. System Architectures

4.1 Introduction

Applying the appropriate level of security to a complex system is one of the biggest challenges utilities are facing today. These challenges are amplified because for security reasons, it is very difficult for utilities to share security best practices outside of the personnel directly responsible with that security. While this paper does not reveal specific architectures being used by any utility, it attempts to outline several typical architectures with various levels of security.

By its nature, security will always be a "cat and mouse" game where new threats require new security methods. Establishing a security strategy also requires a balancing act where any method of restricting access must be balanced with the critical nature of the asset and the limitations placed on employees with substation cyber access rights. It is important and useful to review the various threats to a security system. They are [7]

- the Hacker. The proverbial teenager just looking to break into things. May not even want to do any damage. They often have a lot of computing power and expertise in corporate networking, but typically will not know anything about power systems or utility protocols.

- the Vandal. Indistinguishable from the Hacker except for motive. Wants to break things, and doesn't really care what. Less common than the Hacker, but more dangerous.

- the Terrorist. This is the attacker people are most afraid of, but is actually less likely to occur than many others. Wants to do specific damage and will probably research the target's network and operations. Would need to know something about power systems and utility protocols. To get this information, could enlist the help of...

- the Disgruntled Employee. This is one of the most dangerous of potential attackers, because they already know the utility's security systems, procedures and weaknesses.

- the Competitor. Utilities are required to communicate with, and therefore share networks with, their competitors. The competitor is probably an uncommon but extremely dangerous threats to the utility network because:

  a) utilities cannot simply prohibit all access, but must limit what data competitors can see.

  b) competitors already know about power systems and probably quite a bit about their target's network.

  c) their attack, if it occurs, will likely be subtle, i.e. eavesdropping rather than denial of service, and therefore harder to detect.

- the Customer. Unfortunately, utilities' customers may also be a threat. They are an especially dangerous threat because they often want to commit fraud rather than to simply damage the electrical network. As noted with competitors, the customer's attack may be hard to detect because all they want to do is modify a few key values.

The following portion of this paper reviews several methods of establishing a secure connection to block unauthorized access and allow appropriate access to the two most common types of data in the substation, often referred to as – SCADA or Operational Data and Maintenance or Non-Operational Data. These architectures are representative of systems in-use or being planned by Utilities today.

4.2 Common System

The Figure 1 contains the most common architecture today for access of substation data for Operations and Maintenance personnel.

The Dispatch office connects to the station over a dedicated communications line using a SCADA protocol. The Maintenance Users connect from any computer with a modem to the IEDs through an unsecured port switch. The Unsecured Port Switch can send data to the SCADA Gateway via a standard SCADA Protocol. The connection is made using a SCADA protocol supported by both boxes, commonly DNP. The SCADA Gateway is typically the master and Port Switch is the slave. This connection is limiting and it can be difficult to share data from the SCADA IEDs with the Port Switch. It is also impossible for User's connecting to the Port Switch to access the SCADA IEDs through that connection. Each device must be connected directly to the Port Switch for the remote PCs to access the IEDs.

The need for a Station LAN increases as additional IEDs support Ethernet communications, such as protective relays, RTUs, PLCs, meters, and DFRs. As Ethernet-based IEDs are added to the substation, the common architecture is changed as shown below to support remote connection to the Station LAN.

4.3 Current Station LAN Architectures

Many IEDs contain the ability to communicate via a LAN port. The Figure 2 contains an initial architecture for access of substation data for Operations and Maintenance personnel.

The Port Switch has been replaced by a Terminal Server, which can provide the ability to connect from a remote PC to serial, or Ethernet devices. This capability is provided using PPP. PPP provides the ability to connect to the Terminal Server with Telnet and then tunnel through to the serial IEDs. The Terminal Server would also allow the remote PC to connect directly to the Station LAN. Many Ethernet IEDs and Terminal Servers can also provide web pages to be viewed by browsers connected locally to the Station LAN or remotely via dial-up.

The SCADA Gateway has also been upgraded to include an Ethernet connection to the Station LAN. This provides the ability to remotely access data from the Ethernet IEDs through the Dial-up Port.

4.4 Security

The Port Switch is typically secured with a password only; the Terminal Server can be secured with login IDs and support CHAP. CHAP provides an increased level of security however, it provides only single factor authentication, anyone who has
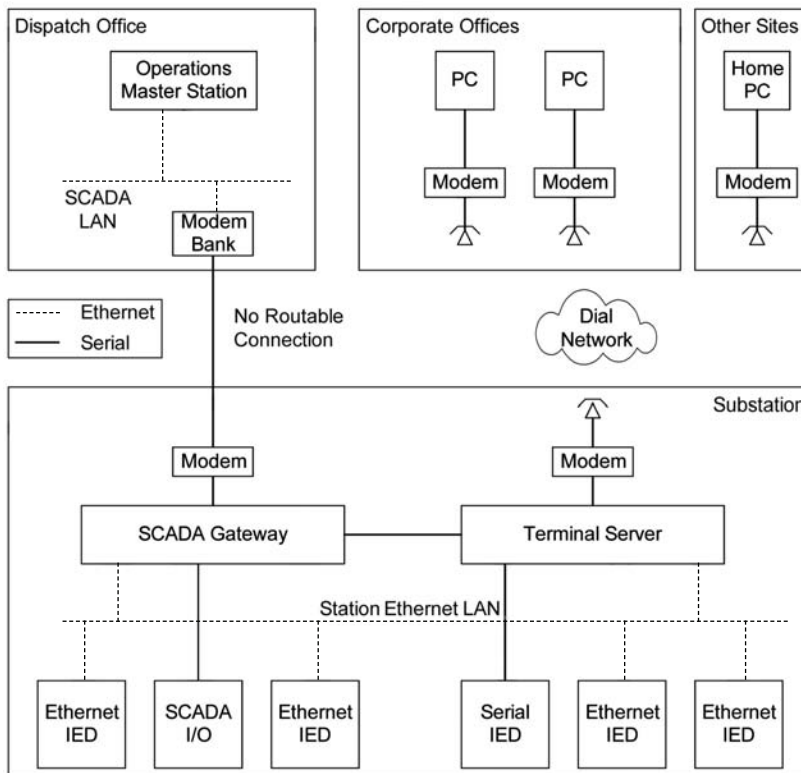
Fig 2.
Existing Architecture with a Station LAN.

the password could log into the Station from any modem. Furthermore, the Ethernet devices would not be secured unless routing was disabled in the Terminal Server between the remote connections and the Ethernet IEDs. Then Ethernet access would not be possible remotely.

5. Secure Architecture #1 – Dial-Up

The gateway meets the NERC security criteria, provides protocol conversion and data concentration for both the Serial and Ethernet IEDs. The gateway also polls those IEDs and concentrates the data in an internal database. Then web pages are generated to display the non-SCADA data providing a convenient tool for viewing fault data from the Stations IED relays together on one web page. Other IEDs can also be displayed including transformer or breaker monitoring and diagnostics, metering, and all the various station analogs including MW loading, voltages, PF, etc.

In order to meet the NERC CIP, two additional capabilities need to be added: the addition of a second authentication factor and the ability to audit successful or unsuccessful login attempts. The architecture shown in Figure 3 illustrates system with the additional NERC CIP functionality.

The system in Figure 3 uses PPP and CHAP providing one authentication factor. SSL and PKI provide a second authentication factor through the use of digital certificates on each PC. Each PC must have SSL and utilize either an additional hardware or software based authorization key before attempting to access the Maintenance Gateway. The Maintenance Gateway will also need to be configured for that User's access and authorization rights. The authorization rights would include rights on the gateway such as View, Control,

Configuration or Security Administration and the specific serial or Ethernet IEDs the User is permitted to directly access.

Strong authentication is achieved through the use of the two factors, the User's ID and password (under CHAP) "Something They Know" and either a hardware or software key/certificate "Something They Have".

The gateway also must record and report successful or unsuccessful login attempts. This supports the NERC CIP requirements of "Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days." [8].

A useful tool to enable security administration for this architecture and the subsequent architectures is a Certificate Authority. A Certificate Authority provides a convenient method to manage Certificates for the Gateways, Master Stations or PC Users. Some Gateways come with an initial Certificate valid for a specific period of time after which a new certificate would need to be issued. As new Users request access to the stations a new certificate would be generated for that user. This tool could also generate a revocation list when a user's access rights are removed.

5.1 Remote access to IEDs

Once the User has been authenticated by the Gateway, the Station IEDs can be accessed remotely. Serial IEDs are accessed through serial tunneling software on the Gateway.
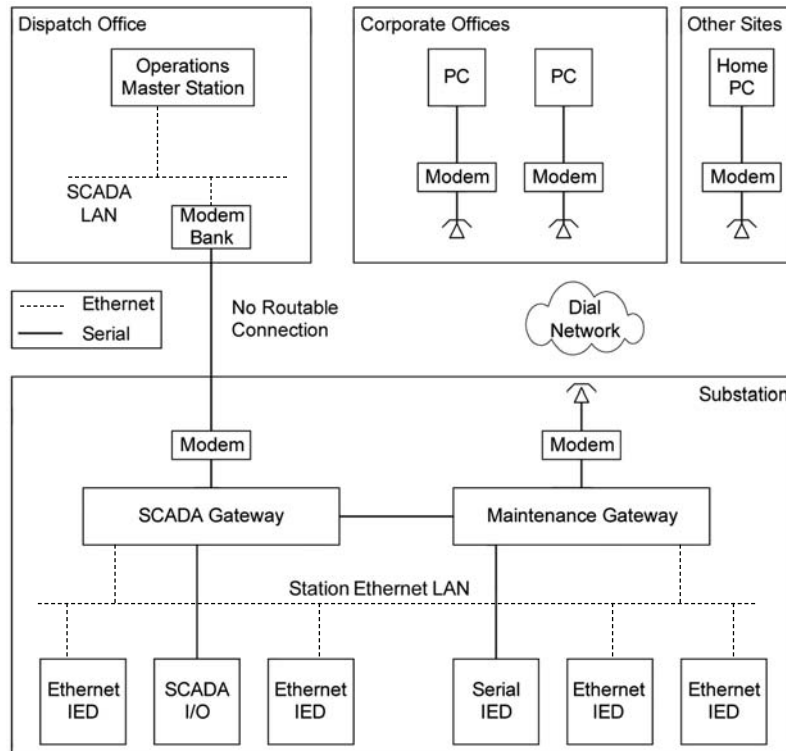
Fig 3.
Secure Dial-Up System.

If the IED software supports Ethernet access, then the serial IEDs are accessed through a serial tunnel established by the Gateway. The User can then access the IED using the IED's native software. The User can connect directly to the IED if that software supports connecting using an Ethernet connection. Otherwise, the User would need to run a virtual serial port software program. That software creates a virtual serial port that the IED software access which redirects the channel to the Gateway and the IED.

The Gateway does control the particular serial and Ethernet IEDs the remote User can access based on their Username and certificate. The serial IEDs are accessed using Secure Terminal Server for the IEDs that the User has authorization to connect. The Gateway also allows an Ethernet connection only to authorized Ethernet IEDs using Secure Connection Relay. These methods restrict remote User access to only the IEDs that the User is authorized to access.

5.2 System Advantages

This system offers security and flexibility. It is the most similar to the dial-up techniques being used today by many Utilities to remotely access the station's non-operational data and IEDs. This architecture provides capabilities of secure access by authorized Users from virtually any dial line.

5.3 System Disadvantages

This system, however, has some significant limitations. Access speeds can be one of the biggest challenges. Also, this technique requires the use of either hard token for each authorized User or a soft token/certificate installed on each User's PC.

Administration of the system is also very demanding. Each Gateway must contain a listing of authorized Users and their IED access rights. This makes the NERC requirement of removing remote access within 24 hours of termination of authorized employees difficult and time consuming.

6. Secure Architecture #2 – Dial-Up Maintenance Server

A similar architecture that allows for centralized password administration of dial circuits is shown in Figure 4. This architecture includes a Secure Dial-Up Maintenance Server installed behind a firewall and connected to a modem bank. This system provides the ability to connect to the Maintenance Gateway and the Station IEDs using a similar technique as the previous Architecture but includes the convenience of LAN connection by the PCs.

Users connect through the Corporate LAN through a firewall to a Maintenance Server. This server provides two-factor authentication with User ID with Password and SSL with PKI including hard token or soft token/certificate. Additionally, each User must have access to the server through the firewall on the network.

The Maintenance Server can be tied to a central Authentication Server which can support Single Sign On (SSO). SSO allows users to only remember one user-ID and password for the Corporate System and for the Maintenance Server/Gateway. It also allows users to authenticate once to gain access to Corporate resources and the Maintenance Server/Gateway. The Authentication Server also can optionally support one time password package (e.g. RSA SecureID).
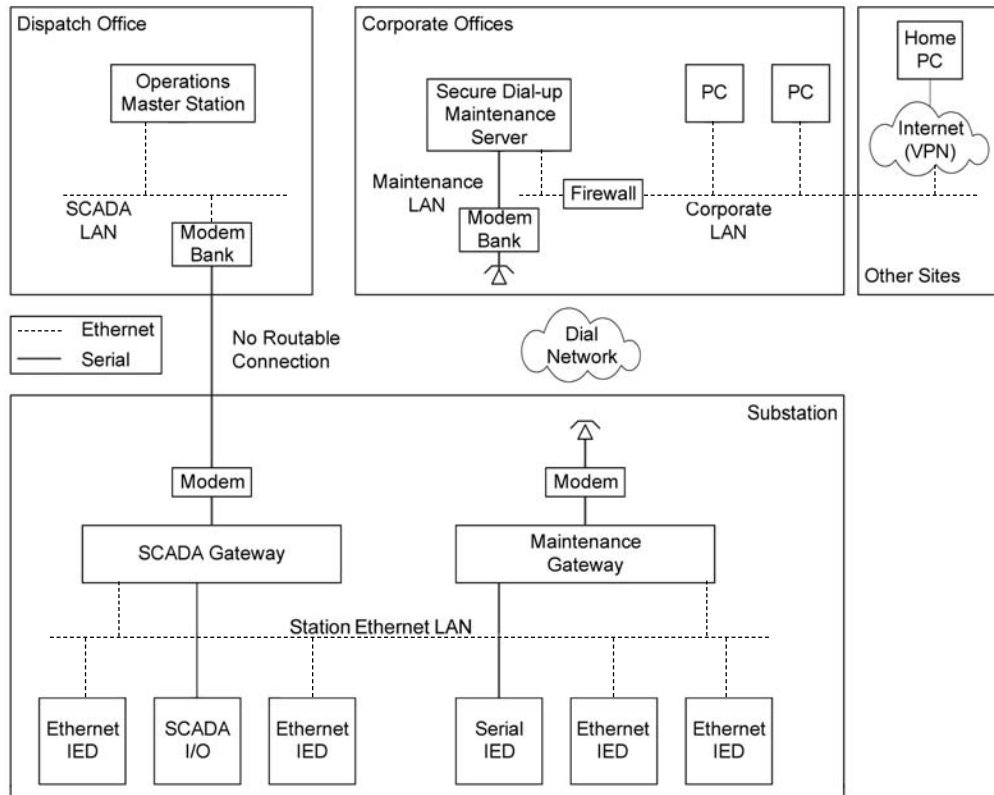
Fig 4.
Serial Maintenance Server.

While the Authentication Server becomes a centralized authority, the Maintenance Server still manages the User's access rights in each Gateway. When a User wants to log-in to a Gateway over the WAN, the User is authenticated by the Maintenance Server then the access rights are set up with the Gateway. The Gateway tracks successful or unsuccessful login attempts. .

Performing authentication on a central server makes it much easier to meet the following CIP requirement: "The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets." [9].

Once a User is authenticated, the server then presents a pick list of substations and IEDs. The User then selects one of the choices and the Maintenance Server then dials one of the modems to the appropriate Maintenance Gateway in the Station using PPP. The Server maintains a randomly generated Maintenance Gateway Password and the appropriate SSL and PKI soft token/certificate for access to the Gateway. The Maintenance Server sends the authenticated User's ID to the Maintenance Gateway for audit trail and sends that User's specific access rights to the Gateway. This allows specific access control for the Gateway's Web Pages, the serial IEDs and the Ethernet IEDs.

The Maintenance Server contains the necessary scripts to establish Gateway pass-through connection to the appropriate IED. Users connecting to the system from a home PC will use their approved method of connecting, usually VPN, to the Corporate LAN and then access the Maintenance Server over that LAN.

As in the previous architecture, the Gateway must maintain a log of success or unsuccessful login attempts for retrieval by the System Administrator.

This method of accessing the system provides some convenience to the Users, as they don't have to remember the phone number for the stations. They also don't need to remember the script necessary to access a particular IED, as the scripts are stored in the Dial-Up Maintenance Server. The Dial-Up Server also randomly establishes and routinely changes the passwords on each Station Gateway. Security is improved since the Gateway's uses a strong password that is kept private.

6.1 Remote access to IEDs

Once the User has been authenticated by the Maintenance Server and the Server connects to the Gateway, the Station IEDs can be accessed remotely by running the appropriate script on the Server. The Server establishes the access control in the Gateway and enables/disables access as appropriate with these scripts. As with the previous architecture, the serial IEDs are accessed through serial tunneling software on the Server and Gateway and Ethernet IEDs are accessed using Secure Connection Relay. These methods restrict remote User access to only the IEDs that the User is authorized to access.

6.2 System Advantages

This system is also secure and flexible and it provides secure access without the requirement of specific Username and Password and maintenance rights at each Gateway because the Maintenance Server provides centralized administration. Whenever the access rights of a User change, the Administrator only changes the Maintenance Server. Significantly reducing the effort required by the Administrator over a system without

a Maintenance Server. Users also don't need to learn different access address or IED scripts to connect to remote devices.

6.3 System Disadvantages

This system requires users to have LAN access to the Maintenance Server before they can access the Gateways in the Station. This will require User's to change the method of accessing the system. Two-factor authentication is still required at the Maintenance Server because it has become another secure access boundary to the Stations. This system also has the speed limitations inherent of dial-up access.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

7. Secure Architecture #3 – O&M Shared High Speed Connection

The architecture shown in Figure 5 adds a WAN connection to the substation shared between the Operations and Maintenance areas. In addition, the dial-up access exists as a backup to the WAN based stations or as an example of a mixture of WAN and dial-up stations.

The O&M WAN connection changes method of access for both Operations (SCADA) and Maintenance access. Both are accessing the station using routable protocols and therefore both access methods fall in the NERC security requirement.

7.1 SCADA Access

SCADA access to the station would utilize a routable SCADA protocol such as DNP3, Modbus IP or IEC 61850. Cyber security for the SCADA system includes SSL using Secure Data Concentrator mode. The Secure Data Concentrator mode allows for SSL security to be applied to any routable SCADA protocols.

Obviously, this requires the security capabilities match for both the SCADA Master Station and the Gateway. Additionally both systems must recognize the other's certificate and SSL/TLS encryption.

7.2 Maintenance Access

The maintenance access is similar to the connection in the previous examples, User-ID with a strong password authentication and SSL with PKI. But now WAN based Gateways are accessed over the WAN eliminating the need for serial PPP. Serial PPP would only be used for substation without WAN connection or as a backup. The speed of the connection will be much faster and more reliable than dial-up.

Also, because both SCADA and Maintenance share the same WAN it would be useful if the WAN is designed to support prioritizing SCADA packet over Maintenance packets so that there is no impact on SCADA whenever large files are being copied to the Maintenance Server.

7.3 Remote access to IEDs

This system is similar to the previous option but provides a LAN connection to the Gateway. Utilizing Secure Connection Relay,
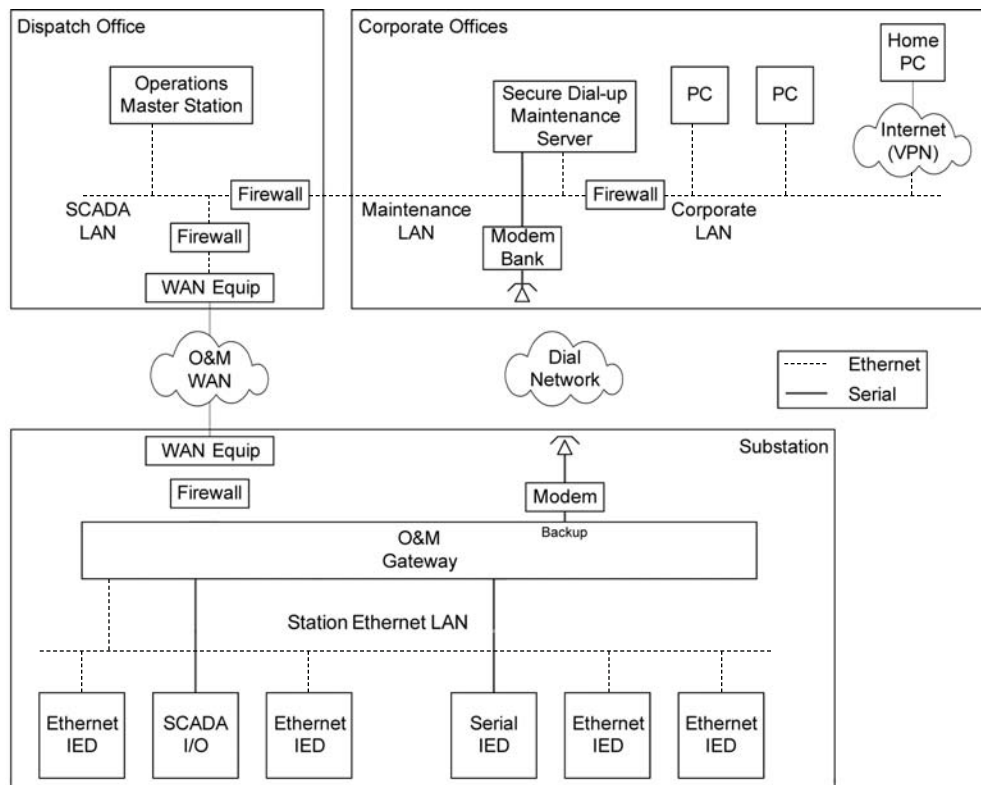

Fig 5.
Shared O&M WAN.

the Server establishes the access control in the Gateway and enables/disables access as appropriate with these scripts. As with the previous architecture, the serial IEDs are accessed through serial tunneling software on the Server and Gateway and Ethernet IEDs. These methods restrict remote User access to only the IEDs that the User is authorized to access.

7.4 System Advantages

This architecture has similar advantages to the previous system and operates at LAN speeds. This provides a significant performance boost for User access.

By sharing the communications channel between the Operations and Non-Operations access, the costs providing two connections is reduced and the two connections can share the bandwidth and performance improvements of the higher speed line. It may be necessary to add the ability to prioritize the Operational traffic over the Non-Operational traffic in the LAN equipment connected to the communications channel.

This system has the advantages of supporting SSO and centralized access right control. Allowing user accounts to be administered in a single location.

7.5 System Disadvantages

Sharing the LAN connection to the Gateway by both Operations and Maintenance can increase the security risks. It is necessary to prevent unauthorized users from gaining access anything on the Dispatch Center. Often this system provides a Maintenance LAN connection that is physically restricted and not connected to the Corporate LAN, increasing security and reducing flexibility for various users.

This system also requires users to have LAN access to the Maintenance Server before they can access the Gateways in the Station. Two-factor authentication is still required at the Maintenance Server.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

8. Secure Architecture #4 – Separate O&M High Speed Connection

This architecture is more popular than the previous architecture where the SCADA and Maintenance WANs are separated into two networks. This could be a completely separate communication channel or a part of a Virtual LAN or VLAN. A VLAN provides the capability for the WAN/LANs to coexist on the same physical network or network equipment. Otherwise, this system is identical to the functionality of the previous system.

8.1 Remote access to IEDs

This system is similar to the previous options but separates the two LAN connections to the Station. Often this connection is operated over the same physical connection using two Virtual LANs, or V-LANs. Equipment connected to each end of the communications channel separate the two V-LANs into two separate physical LANs at each end. Often, this equipment also allows the ability to dynamically assign channel bandwidth between the two V-LANs as necessary.
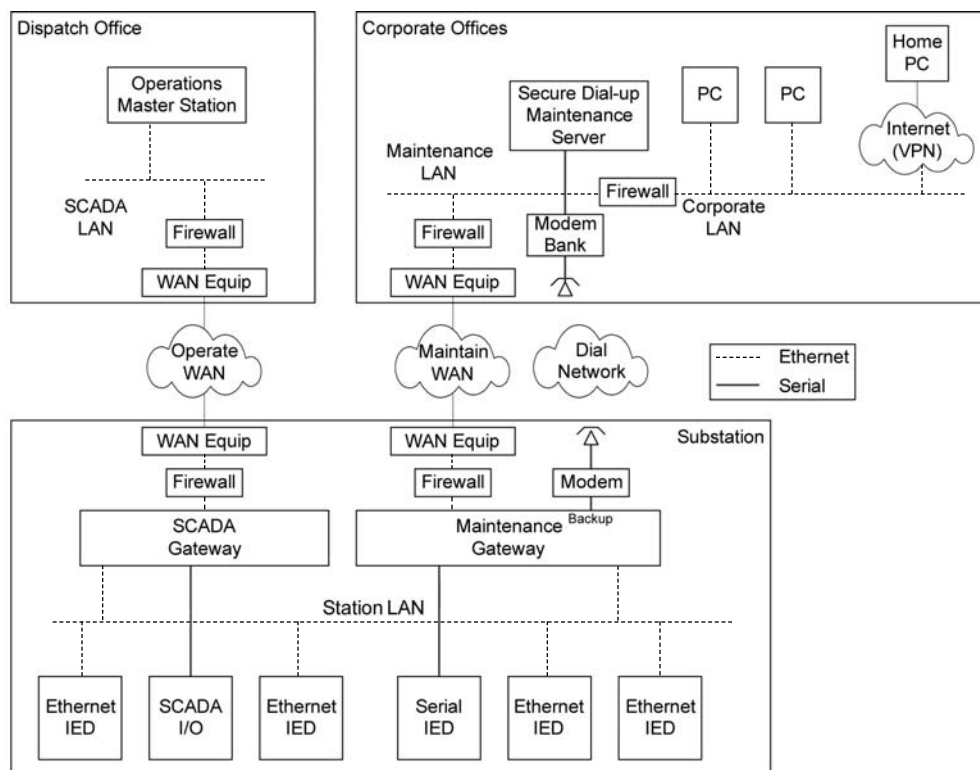

Fig 6.
Separate O&M WAN.

8.2 System Advantages

This architecture has similar advantages to the previous system and operates at LAN speeds with improved security because there is no connection to the Operations LAN from the Maintenance LAN.

By sharing the communications channel using V-LANs between the Operations and Non-Operations access, the costs can be reduced and the bandwidth can be shared while reducing the security risks.

This system has the advantages of supporting SSO and centralized access right control. Allowing user accounts to be administered in a single location.

8.3 System Disadvantages

This system also requires users to have LAN access to the Maintenance Server before they can access the Gateways in the Station. Two-factor authentication is still required at the Maintenance Server.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

9. Secure Architecture #5 – Separate Station and Corporate LANs

This architecture breaks the routable connections between the Maintenance LAN and the Corporate LAN or the Station LAN. This architecture is functionally identical to the system previously described however it provides an improved level of security and isolation of the various functions.

IEDs that need to share data with both the SCADA and the Maintenance Gateway must do so over a non-routable connection. Those IEDs must communicate over two communication channels or the two Gateways to share IED data serially between the Operations and the Maintenance Gateways. This breaks the routing connection between the two LANs in the substation completely.

The Corporate LAN is also disconnected from the Maintenance LAN. A new Maintenance Database Server is added to the system with two NIC cards. The Maintenance Server is designed not to create a routable connection between the two LANs. The Maintenance Gateway in the station will automatically send data and oscillography files to the Maintenance Database Server. Users on the Corporate LAN can access the substation data on the Maintenance Database Server without having a direct connection to the station. The Maintenance Server must be secured to prevent a Corporate LAN User from gaining access through to the Maintenance LAN.

Devices connected to the Dispatch Office side of the Maintenance LAN can access the Maintenance Gateway and with SSL and PKI can access the serial and Ethernet IEDs directly. Of the security architectures discussed here, this architecture is the most secure but can be the most complicated.

9.1 Remote access to IEDs

This system is similar to the previous options but separates the Maintenance LAN from the Corporate LAN. It also separates
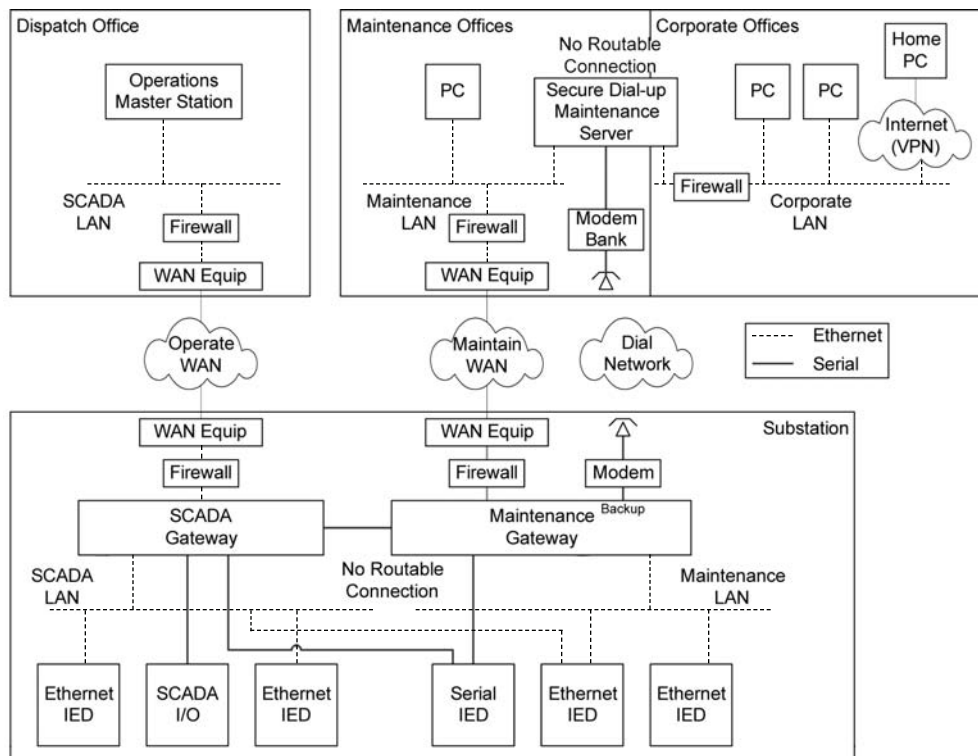

Fig 7.
Separate O&M Station LAN.

the Station Operations and Maintenance LANs. Access to the IEDs is only provided by users connected directly to the Maintenance LAN. Users on the Corporate LAN can access a new Maintenance Database Server which provides data from the Station IEDs and the Gateway without providing remote access from users outside the Maintenance LAN.

9.2 System Advantages

This system provides the greatest level of security between the Corporate LAN and the Maintenance LAN because there is no routable connection between the two LANs. User's can access data from the Stations on the Maintenance Server and can access the IEDs directly from the Maintenance LAN which is often only available in a physically secure location. Two-factor authentication is no longer required by the Corporate LAN Users because they cannot gain access to the Gateways directly from the Corporate LAN.

This system has the advantages of supporting SSO and centralized access right control. Allowing user accounts to be administered in a single location.

9.3 System Disadvantages

This system is more complicated and restricts remote access only to users who have LAN access to the Maintenance LAN before they can access the Gateways in the Station. Two-factor authentication is still required at the Maintenance Server for these users. This system also is more expensive and requires dual serial communications to the IEDs and/or a serial data connection between the SCADA and Maintenance Gateways.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

10. Summary

As utilities seek to balance the critical nature of the asset and the cyber threat with the access requirements of authorized Users, the search for solutions will continue to be an ongoing challenge for both Utilities and Security Solution Suppliers. Most Utilities are implementing a mix of the architectures outlined in this paper depending on the critical nature of the asset and the communications available to the site.

Answers to the following questions will help determine the architecture that fits best:

- what Users need access to the data from the IEDs and who needs direct access to the IEDs?

- what type of communications exists or is economically available?

- what type of substation architectures are implemented or planned? Do they include Ethernet?

- will the Maintenance LAN and Operations LAN be

connected? At the Substation, share a communications line, or at the dispatch office?

- how will the Corporate LAN be connected to the system if at all?

- will authorized Users be able to access the data or the IEDs from remote locations?

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Addressing Window Type Transformer Proximity Errors

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1. Abstract

This paper documents the problem of window type current transformer transformation errors in the presence of stray magnetic fields and presents a practical approach to addressing the problem. Specific situations that present a problem for window type current transformers are identified. A method for calculating local saturation will be outlined and validated by test on different field configurations. Alternative methods to address the issues are introduced that can be validated by the model.

2. Introduction

It is known that situations that result in stray magnetic fields can produce window type current transformer (CT) transformation error problems. This is particularly true when primary currents are very large, cores are relatively small. The primary conductor is not centered and the core is oddly shaped, however, the primary current carrying conductors change direction soon after exiting the CT window, or other phase conducts are in close proximity to the outside edge of the CT window. Further, it is worth noting that, not only are these situations possible, they are probable, and exist to some degree in almost every CT installation.

This paper reviews the problems associated with mechanical layout complications. Test data is presented to document the nature of the problem. Several situations are addressed. Test data is presented in a format that leads logically to the problem prediction method suggested in this paper. Next, a method is be defined and verified that allows for the prediction of transformation errors. The error prediction method is independent of the often very complicated magnetic configurations in which window type CTs are expected to operate. The technique in fact, predicts a problem that result from the sum of all of interacting field shaping mechanical layout conditions and the particular characteristics of the CT itself.

Finally, techniques for minimizing errors are presented. Aside from the obvious approach of changing primary conductor routing, which is an expensive or nearly impossible task, techniques are explained that can be performed adjacent to, or even within, the CT housing.

3. CT Saturation Issues

Window type current transformers are almost never installed in a uniform magnetic field. Fortunately, they are resilient passive devices. The end user rarely observes the effects of field non-uniformity. This is primarily because the CT core is not typically saturated. CTs normally operate at relatively low flux density. The stray magnetic fields that should not couple to the core of the CT pass through the CT core, exiting as they entered. The effect is that they do not impact the resulting secondary current signal.

Problems result when the magnetic flux density in the CT core exceeds what the normally very efficient material can support. In this situation, we say that the core is saturating. Universally accepted techniques are practiced which use manufacturer supplied excitation curves for overcurrent analysis. Industry standard methods of overcurrent specification also exist [1] [2]. But all of these only address performance expectations in uniform magnetic fields.

Significant problems can result when the sum of all current carrying conductors cause the magnetic flux density in the CT core to exceed the material capacity in localized regions. In this situation, we usually say that the core is saturating locally. There are no well-defined techniques to address this situation, even though the situation is very common. Some switchgear manufacturers test CTs in standard locations, and some specification engineers ask for cross current compensation, but often fail to specify a complete description of the installation environment that is required to thoroughly define the degree of required compensation.

Until localized core saturation occurs, the metering accuracy is only slightly affected by non-uniform core flux density. Due to the fact that most relay applications do not require high accuracy in overcurrent conditions, the effect of the locally reduced material permeability and the resulting higher magnetizing losses is usually negligible.

Localized core saturation does not necessarily have the catastrophic effects that entire core saturation has on signal loss. It will be later illustrated that local core saturation will cause the CT error to grow significantly, but it does not cause the almost complete loss of signal that results from saturating the entire core. It is not safe to make generalized assumptions about magnitude and wave shape distortion. A well-designed system will avoid this issue by preventing local saturation. This paper offers guidelines on how to design such a system.

4. Localized CT Saturation

Situations that result in localized CT core saturation can be divided into two categories: Lack of concentricity of fields that should couple to the CT core and the presence of fields that are in proximity to the CT that should not couple.

Concentricity problems result when the primary current carrying conductors are not centered in the CT window, or the CT window is irregular in shape. It is common to use bus conductors that are rectangular in shape, which inherently brings the edge of the bus closer to one side of the CT, but more serious problems result when, out of convenience, the CT is allowed to rest on the face or the edge of a bus bar. It is also common to use more than one cable to carry current, and installers are usually content to simply verify that all conductors pass successfully through the CT window. In situations where differential current is to be measured, as in the case of ground fault detection, users often fail to group conductors to cancel magnetic fields that should not couple to the CT core. Finally, and probably the most detrimental situation, is the practice of abruptly turning the primary conductor that passes through a window CT. For example, it is common practice to mount CTs on low voltage bus bars and slide them back against a 90° turn within power handling distribution equipment.

The second, and probably the more difficult issue to address, is the proximity of adjacent conductors. This usually involves the presence of two other phases in a three-phase system or the return conductor of the same phase. Further complicating this situation is that these conductors rarely extend in a straight line and may turn abruptly very near the CT. Interference from the same phase is prevalent in fused switch and circuit breaker applications where bus bars leave riser bus, pass through the circuit protection device and out the back of the gear.

The goal of a switchgear, generator, or control equipment manufacturer to shrink gear and reduce size and losses is a complicating factor for the use of window type CTs.

5. Saturation Phenomena Documentation

The following examples indicate how window current transformers can be saturated by poor concentricity and the presence of a nearby current carrying conductor.

A. Concentricity

A 1000:5, C50, CT was mounted as indicated in Figure 1. Primary current was passed through the window in a 46" × 46"
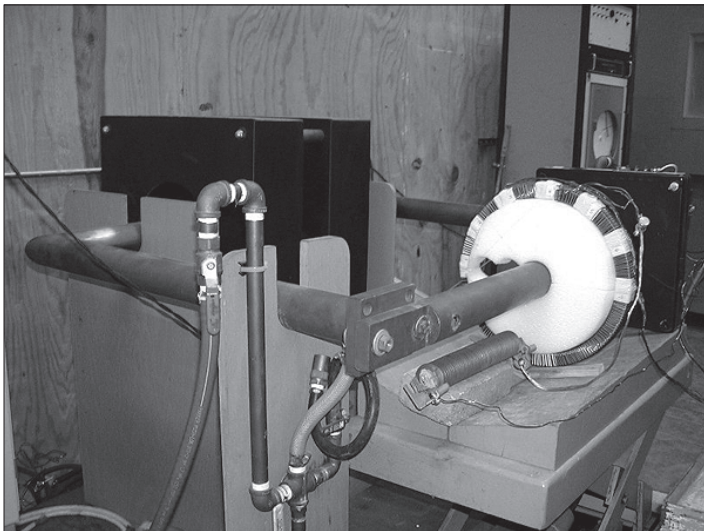

Fig 1.
Concentricity Test Configuration.

square path. This large path was used to ensure that the return conductor had very little influence on the unit under test. In order to measure the flux in the core, search windings were placed at 30° intervals around one hemisphere of the toroidal core.

Knowing the proportional relationship of flux density to induced voltage, it is possible to measure the local flux density in the core with the use of a search winding located over the core in the area of interest.
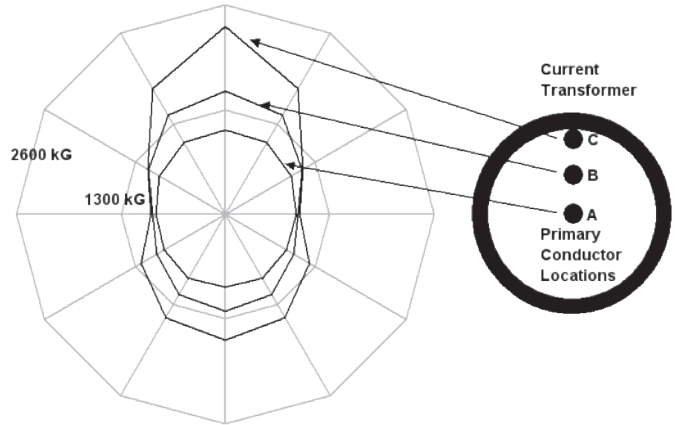

Fig 2.
Core Flux Density Characteristic due to Lack of Concentricity at 1kA.

The relationship of induced voltage to core flux @ 60 Hz:
$$E = 1.72 * B * A * T * 10^{-5} \tag{1}$$

Where:

E = Voltage sensed by a search coil

$\mathbf{B}$ = Flux in the core (gauss)

A = Area (sq. in.)

T = Number of turns

(This formula will change slightly based on particular assumptions like core material stacking factors, etc.)

Provisions were made to move the primary conductor from the center position to a position midway between the center and the inside edge, and then against the inside edge. At 1000 A, the voltage was measured and plotted in a radar plot to indicate the magnitude of flux in the core around the circumference of the toroidal transformer. The distance from the center represents the magnitude of the flux density and the angular location represents the angular location on the CT core. This flux density is plotted in Figure 2. The inner circle represents the search coil voltage with the primary in the center of the CT window. The shape is round and exactly the magnitude predicted by equation #1 based on the CT core size, winding resistance and a connected 0.5 Ω burden. The highest magnitude of flux density resulted from positioning the primary conductor against the transformer inside wall. Near the bus bar, the flux density was over 2.5 times the calculated density. The curve in between the extremes represents a 50% displacement of the primary conductor.

Figure 3 indicates where problems start to arise. The primary current was raised from 1kA, to 5kA, then to 10kA. This plot has been re-scaled to indicate all three current levels. Additionally, a circle is drawn at 18k gauss - the point at which the core starts
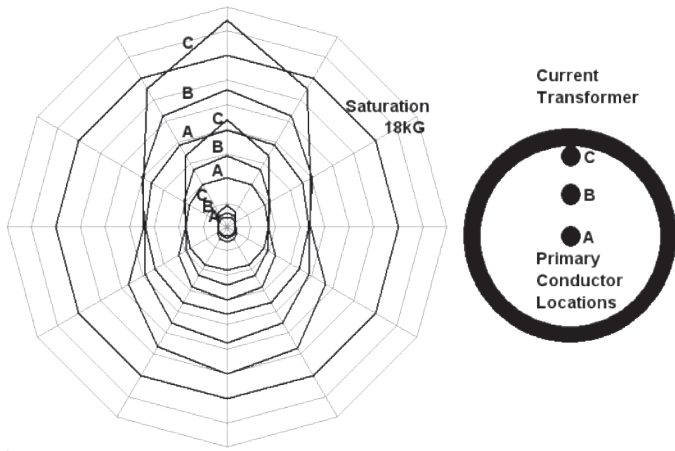
Addressing Window Type Transformer Proximity Errors

Fig 3.
Core Flux Density Characteristic due to Lack of Concentricity - At 1kA, 5kA, and 10kA.

to saturate and transformation begins to fail. At 10x nominal rating, or 10k amperes, this CT is saturating at maximum primary conductor offset. Notice that the shapes of the curves are identical at each current level and grow in magnitude proportional to the primary current. This fact will be critical in our predictive model to follow.

B. Proximity

The same 1000:5, C50, CT was tested with the primary current routed through the center of the window. This time the return conductor was intentionally passed in close proximity to the outside of the CT window. See Figure 4 for the set-up.

The diameter of the mean magnetic path was 13.75". The center of the return conductor was located first at 6.875", then at 3.375", then at 1.25" from the centerline of the CT wall. Figure 5 represents the voltage measured, which is exactly proportional to the flux density in the core measured at 30° intervals. At 8kA it can be seen that the core starts to saturate locally when the return conductor is closest to the CT wall. Again notice that,
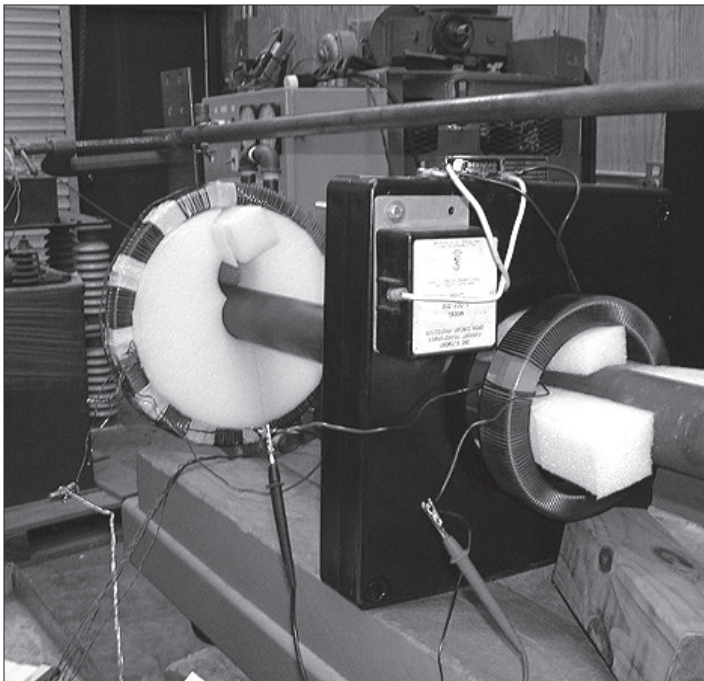

Fig 4.
Proximity Test Configuration.

as in the cases of poor concentricity, the shapes of the curves are identical at each current level and grow in magnitude proportional to the primary current. Again, this fact will be critical in our predictive model to follow.

Figure 6 is a plot of the flux intensity measured in a CT where the primary conductor is routed through the center of a 1000:5, C50 CT, but the bus turns 90° just 3.375" from the center of the current transformer. It can be observed that the shape of the flux plot is quite odd, indicating that the distortion can be either subtractive or additive depending on the actual bus layout. But as before, the shapes of the curves are identical at each current level, and grow in magnitude proportional to the primary current.

Data was taken at other CT ratios, bus configurations and CT shapes to explore the compounding effect of stray field problems. In all cases, the error was noted to track linearly, as in all the configurations illustrated herein.
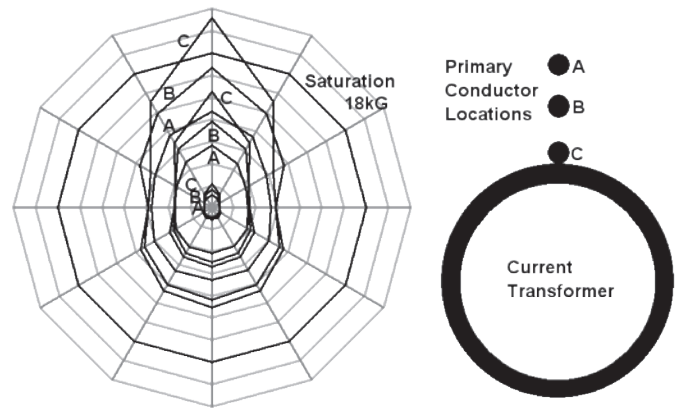

Fig 5.
Core Flux Density Characteristic due to Proximity of a return conductor - At 1kA, 5kA, and 8kA.
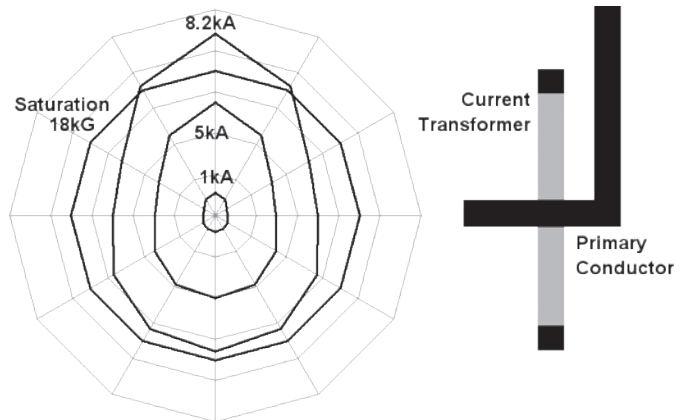

Fig 6.
Core Flux Density Characteristic due to a primary conductor turn of 90° - At 1kA, 5kA, and 8.2kA.

6. Problem Characterization

While attempts have been made to calculate the extent of local CT saturation, they have proven to be both cumbersome and complicated, so that they are virtually ineffective for the practitioner [3]. Further, they are inadequate because the problems that result in local saturation are almost always compounded by the combination of phase shifts and physical layout complexity.

The ultimate solution lies in the scalability of the flux density in the localized region of a core based on a fixed mechanical system by observing small signal phenomena. Then protection, and sometimes even metering, flux density levels can be calculated to see if the CT will experience saturation.

It is very easy to calculate the expected flux density in a CT core based on the internal resistance, the connected burden, the primary to secondary turns ratio, and the magnitude of primary current. CT designers do this routinely and with very high accuracy. If this expected flux density is subtracted from the stray flux density measured by search coils, then an error, or "nuisance" flux level can be determined for any region of a CT core. Further, based on the similarity of curve shapes, it is possible to extrapolate this error to any desired operating level to see if a problem exists in an application.

Returning to our examples, we will plot the following: Stray Voltage/Primary Current vs. Angular Location, where the absolute value of "Stray Voltage/Primary Current" represents the absolute value of a normalized error signal. Angular Location is the position on the core. Figure 7 is a plot of concentricity test data indicated in Figure 3. Figure 8 is a plot of proximity test data indicated in Figure 5, and, Figure 9 is a plot of proximity test data indicated in Figure 6. The magnitude and profile are very hard to predict, but fortunately, once known, the profiles are easily and accurately scalable.

The plots serve to verify that the relationship between stray voltage (i.e. stray flux density) and primary current is linear at any particular region of the core. The plots that overlap are actually at different primary currents. The shifts in the clusters of data reflect different bus bar arrangements.

To the casual observer, it is obvious that data need only be gathered from the regions where the flux density peaks because this is where the core will first saturate. Going forward it becomes clear that it is not necessary to plot the data in Figures 7, 8 and 9. The critical information can be gathered from one or two search coils located on the CT where the CT core will be most influenced by a current carrying conductor. Other tests were performed at only the test points of concern to verify that this linearity exists for all CTs.

To the practitioner, the ability to identify a problem can be reduced to a simple process:
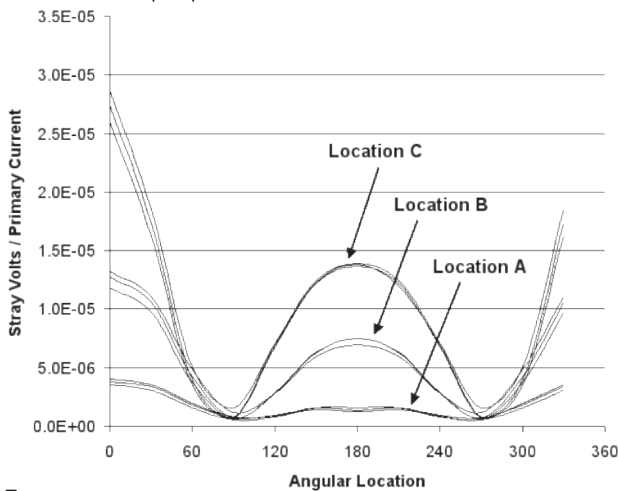

Fig 7.
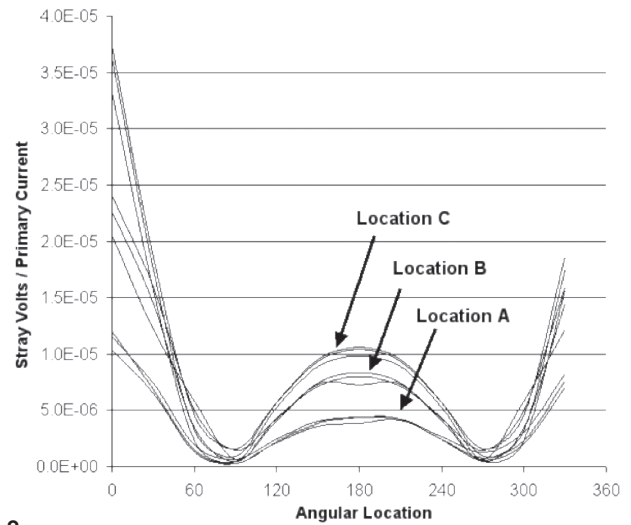*Normalized error due to Lack of Concentricity - At 1kA, 5kA, & 10kA.*

Fig 8.
Normalized error due to Proximity of a Return Conductor - At 1kA, 5kA, & 8kA.
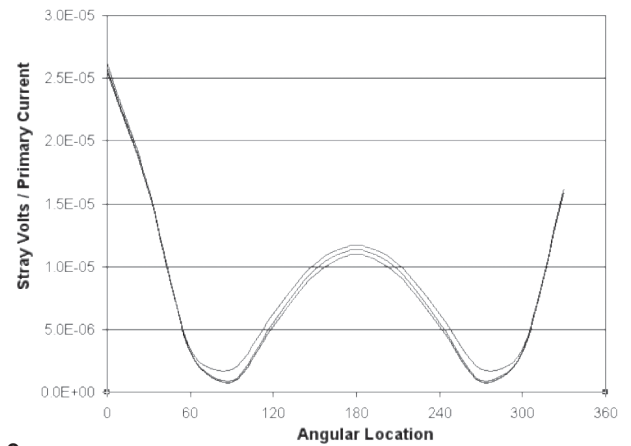

Fig 9.
Normalized error due to a primary conductor turn of 90° - At 1kA, 5kA, & 10kA.

1. Lay out a simple simulation test at a low current level.

2. Using one or more search coils, measure the total local Voltage (V_{TL}) in any area of concern (most probably where conductors are closest).

3. Calculate the voltage that corresponds to the "expected" low level flux in the test (V_L).

4. Subtract the calculated "expected" low level voltage (V_L) from the voltage measured by the search coil (V_{TL}), and multiply this difference by the ratio of the "expected" final primary current (I_H) divided by the primary test current level (I_L). This will yield the expected high current voltage due to stray flux (V_{EH}).

5. Finally add to this expected stray flux voltage (V_{EH}) the calculated "expected" core flux voltage (V_H) for the final high primary current.

6. Calculate the voltage that corresponds to saturation flux density for the CT construction in question (V_{SAT}).

7. If the extrapolated stray flux voltage (V_{EH}) plus the calculated expected final flux voltage (V_H) is greater than the saturation point voltage (V_{SAT}), then the CT will not perform accurately because this section will be in saturation.

The following must be true to ensure no local saturation:

$$V_{SAT} \geq V_{EH +} V_H \qquad (2)$$

Where

V_{SAT} = Volts/Turn from a core at saturation

V_{EH} = Volts/Turn in a region of a core due to stray fields at maximum current

V_H = Volts/Turn requirement at the application high current level in an ideal magnetic field condition necessary to support the connected burden

V_{EH} is derived from linear extrapolation from a test set-up data as follows:

$$V_{EH} = (V_{TL} - V_L) * (I_H / I_L) \qquad (3)$$

Where

V_{TL} = Volts/Turn measured at the test level

V_L = Volts/Turn requirement at the test level in an ideal magnetic field condition necessary to support the connected burden

I_H = Actual in-service maximum current

I_L = Test set-up current

It is recognized that interference can be difficult to model. Some sources will be out of phase and others will have a magnitude that is not proportional to the primary signal. Metering simulations will usually be balanced three phase currents, while circuit protection simulations will typically be unbalanced, based on various fault conditions. It is incumbent on the simulation designer to address these permutations by defining proper boundary conditions. As an aid to the designer it is worth observing that in-phase opposing flux will be more detrimental than phase shifted flux. Therefore, it may be possible to envelop three-phase problem situations with single-phase test configurations. Scaling of primary conductors, transformer cores, wire resistance and burdens is not recommended without further investigation. This model is intended only for the identification of local core saturation due to increases in current magnitude.

7. Model Verification

Use this technique to analyze two transformers.

Case Study #1

A toroidal 5000:5 CT of mean diameter 9.34" is mounted on a centered primary bus bar. A return conductor is routed 2.875" from the centerline of the mean diameter. Will this CT saturate at the nominal current of 5kA?

The unit was tested at 1250 amps to predict performance at 5000 amps.

Based on the transformer design and connected burden the following was calculated:

$V_{SAT} =$ 0.0463 Volts/Turn

V_L = 0.00265 Volts/Turn

V_H = 0.0106 Volts/Turn

Using the equation:

$$V_{EH} = (V_{TL} - V_L) * (I_H / I_L)$$

Then

$$V_{EH} = (0.0196 - 0.00265) * (5000 / 1250) = 0.0678$$

Next we must satisfy this condition:

$$V_{SAT} \geq V_{EH} + V_H$$

Since 0.0463 $\geq$ 0.0678 + 0.0106 is not true, the CT will be in local saturation.

By calculation, the total search coil voltage should have been 0.0678 + 0.0106= 0.0784 volts. The voltage measured was 0.0686, indicating saturation. And indeed, the ratio error of the CT was measured at -4.8%.

Case Study #2

A rectangular 1000:5 CT with nominal core dimensions of 4.875" by 10.625" is mounted on a bus bar offset 2.44" from the short leg of the core. See Figure 10 for a picture of the set-up. A return conductor is routed 2.44" from the centerline of the long leg. This test represents an offset primary, nearby return conductor and a less than ideal core shape. Will this CT saturate at the nominal current of 1kA? Will this CT saturate at the nominal current of 3kA?

The unit was tested at 500 amps to predict performance at 1000 and 3000 amps. The local saturation voltage was measured at the point closest to the return conductor.

Based on the transformer design and connected burden the following was calculated:
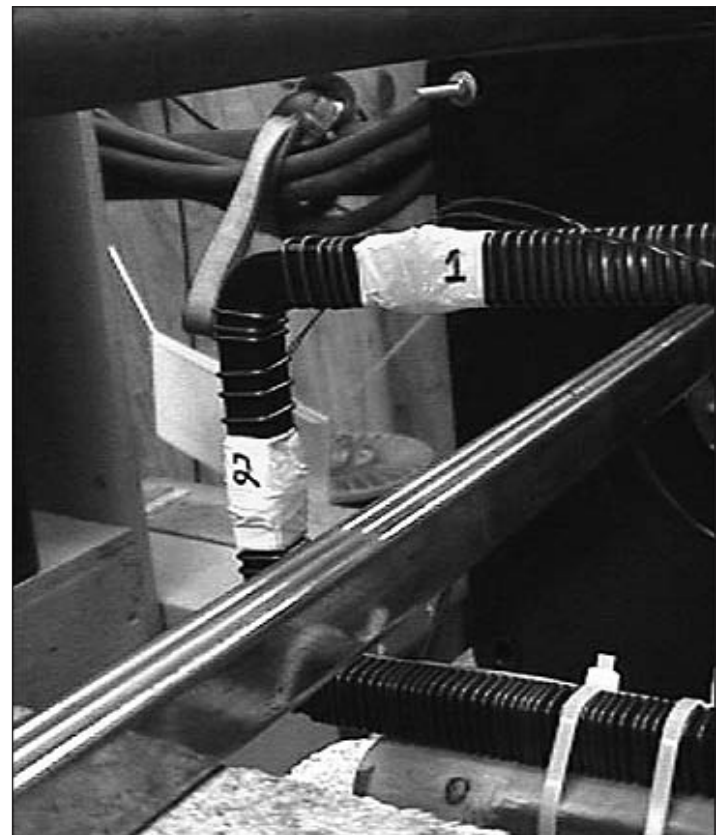

Fig 10.
Rectangular CT Proximity Test Configuration.

$V_{SAT} = 0.0735$ Volts/Turn

$V_L = 0.00273$ Volts/Turn

$V_H = 0.00545$ Volts/Turn

Using the equation:

$V_{EH} = (V_{TL} - V_L) * (I_H / I_L)$

Then

$V_{EH} = (0.0160 - 0.0.00273) * (1000 / 500) = 0.0265$

We must satisfy this condition:

$V_{SAT} \geq V_{EH} + V_H$

Since $0.0.0735 \geq 0.0265 + 0.00545$, the CT will not be in local saturation. The unit was found to be accurate at 1kA by test.

To verify the model, the predicted voltage of $0.0265 + 0.00545 = 0.031$ volts/turn was compared to the measured voltage of 0.032 volts/turn.

This calculation was repeated for a 3000 amp primary, using the same relationship of:

$V_{SAT} \geq V_{EH} + V_H$

Now, since $0.0735 \geq 0.0795 + 0.016$ is not true, then the CT should be in gross local saturation. The unit was tested and found to be 8.8% in error.

8. Addressing Local Saturation

At least four methods can be employed to address local saturation: Magnetic shielding, core size increase, transformer redesign with larger secondary wire, and cross current compensation.

Magnetic shielding is usually accomplished with a stack of laminations within the housing of a CT case or between the CT and the problem source of flux. The size of the shield may sometimes be a problem, and tests must be performed at maximum current levels to verify that the shield works as intended. Care must be taken to secure the shield to reduce noise and to make sure that it will remain in place due to magnetic forces. Do not use the modeling method of section 5 to scale the effectiveness of this technique.

A brute force method of solving the problem of localized core saturation is to increase the cross sectional area of the core. It is a straightforward exercise to return to section 6 of this paper and see that by increasing the capacity of the core to handle more voltage, saturation can be avoided.

Another simple method that can be employed, when the CT has many turns and is not in gross saturation is to increase the secondary magnet wire gage. Remember that the flux in the core is proportional to the required voltage to drive the secondary current. In many cases, the resistance of the wire in a high ratio CT may be greater than the connected "burden". Most CT designers are well aware of the fact that a larger magnet wire used for the secondary winding construction may reduce the voltage demand to a level where the CT will come out of saturation. It is often possible to reduce the sum of the

stray and required flux in a local region of a core by reducing the required flux.

Cross current compensation, sometimes called "core balance compensation", has become the shielding method of choice by many who do not have the option to increase the core size or wire size due to weight, size, or cost constraints. The practice is usually to involve some portion of the secondary turns in parallel compensation, then to wind the balance of the secondary turns over the compensation windings in series with the compensation windings. These parallel windings are located in quadrants, or sections. If a major problem is being addressed, several layers of windings may be connected in parallel before the balance of the CT winding is series-connected. See Figure 11 for a typical winding configuration. The function of these parallel windings is to allow current to flow between them to counter the unbalanced flux in the core. Only the number of sections wound and the wire resistance in the sections limit the effectiveness of parallel winding. As the resistance in the paralleled wire sections approaches zero, then the voltage (and flux) in the core approaches a balance.
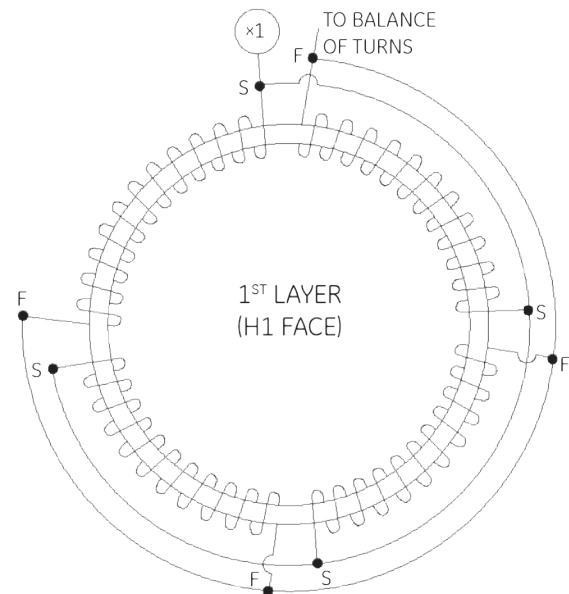

Fig 11.
Windings on a Cross Current Compensation Transformer.

Figure 12 indicates how the addition of cross current compensation vastly improves flux unbalance in the transformer used for the proximity error example in Figure 4. The small inner circle represents ideal balanced flux density. The outer circle represents saturation flux density. Note how much better that CT performs with the addition of 8 sections of core balance windings.

It is important to note that if cross current core balance compensation is used to eliminate a local core saturation problem, then the fix can be verified using the scaling technique of section 5.

9. Conclusions

The identification of probable CT saturation problems is simple in an ideal situation where concentricity with primary conductors is
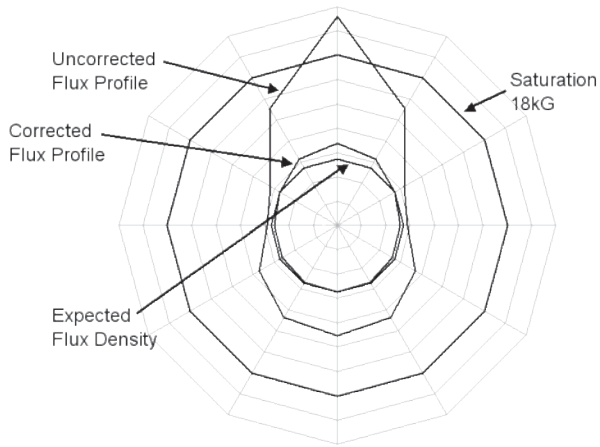
Fig 12.
Core flux density due to proximity of a return conductor before and after the addition of core balance windings at 8kA primary current.

ensured and the influence of other current carrying conductors is not an issue. This "ideal" situation is rarely the case, so caution should be observed under the following conditions, particularly when they are compounded: Primary conductors are not centered in a window, the core is not toroidal, the CT is expected to operate at very high current levels momentarily, other current carrying conductors are in very close proximity to a CT, a current carrying conductor turns abruptly very near the CT, the core cross section is small compared to the diameter of the CT.

11. References

Standards:

[1] IEEE Std. C57.13-1993, "IEEE Standard Requirements for Instrument Transformers"

[2] IEC60044-1: 1997, "Instrument Transformers- Part 1: Current Transformers")

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Transformer Protection Principles

1. Introduction

Transformers are a critical and expensive component of the power system. Due to the long lead time for repair of and replacement of transformers, a major goal of transformer protection is limiting the damage to a faulted transformer. Some protection functions, such as overexcitation protection and temperature-based protection may aid this goal by identifying operating conditions that may cause transformer failure. The comprehensive transformer protection provided by multiple function protective relays is appropriate for critical transformers of all applications.

2. Transformer Protection Overview

The type of protection for the transformers varies depending on the application and the importance of the transformer. Transformers are protected primarily against faults and overloads. The type of protection used should minimize the time of disconnection for faults within the transformer and to reduce the risk of catastrophic failure to simplify eventual repair. Any extended operation of the transformer under abnormal condition such as faults or overloads compromises the life of the transformer, which means adequate protection should be provided for quicker isolation of the transformer under such conditions.

3. Transformer Failures

Failures in transformers can be classified into

- winding failures due to short circuits (turn-turn faults, phase-phase faults, phase-ground, open winding)
- core faults (core insulation failure, shorted laminations)
- terminal failures (open leads, loose connections, short circuits)
- on-load tap changer failures (mechanical, electrical, short circuit, overheating)

Conditions	Protection Philosophy
Internal	
Winding Phase-Phase, Phase-Ground faults	Differential (87T), overcurrent (51, 51N) Restricted ground fault protection (87RGF)
Winding inter-turn faults	Differential (87T), Buchholz relay,
Core insulation failure, shorted laminations	Differential (87T), Buchholz relay, sudden pressure relay
Tank faults	Differential (87T), Buchholz relay and tank-ground protection
Overfluxing	Volts/Hz (24)
External	
Overloads	Thermal (49)
Overvoltage	Overvoltage (59)
Overfluxing	Volts/Hz (24)
External system short circuits	Time overcurrent (51, 51G), Instantaneous overcurrent (50, 50G)

- abnormal operating conditions (overfluxing, overloading, overvoltage)
- external faults

4. Innovative GE Multilin Solutions to Transformer Protection Applications

4.1 Differential Characteristic

The major operating challenge to transformer differential protection is maintaining security during CT saturation for external faults while maintaining sensitivity to detect low magnitude internal faults. CT saturation reduces the secondary output current from the CT, and causes a false differential current to appear to the relay. GE Multilin differential relays meet this challenge in the following ways:

- the restraint current is based on the maximum measured winding current, as opposed to the traditional magnitude sum of the currents. This ensures ideal restraint for the actual fault condition, balancing sensitivity and security.

- the differential element uses a dual slope-dual breakpoint characteristic. The differential element can be set to account for both DC and AC saturation of the CTs, ensuring security, while maintaining sensitivity.
Available in the T60, T35.

4.2 Inrush Inhibit during Transformer Energization:

The transformer energization resembles the condition of an internal fault. If no inhibiting mechanism is provided, the differential element will trip. The magnetizing inrush current has significant 2nd harmonic content. The level of 2nd harmonic current can be used to differentiate between inrush and a fault condition. The UR T60 and T35 GE Multilin transformer relays use two different 2nd harmonic modes to inhibit the differential element for inrush.

Traditional 2nd harmonic blocking – The traditional 2nd harmonic restraint responds to the ratio of the magnitudes of the 2nd harmonic and the fundamental frequency currents.

Adaptive 2nd harmonic blocking– The adaptive 2nd harmonic blocking responds to both magnitudes and phase angles of the 2nd harmonic and the fundamental frequency currents. The differential element correctly distinguishes between faults and transformer energization, when the 2nd harmonic current is less than the entered 2nd harmonic setting. While levels of 2nd harmonic during inrush often do not go below 20%, many transformers are susceptible of generating lower 2nd harmonic current during energization. Setting the 2nd harmonic restraint below 20% may result in incorrect inhibit of the differential element during some internal fault events. The adaptive 2nd harmonic blocking allows settings in the traditional 20% range, while maintaining the security of the differential element against inrush.

Available in the T60, T35.

Ground fault current for impedance grounded neutral transformer for faults at different % of the winding.
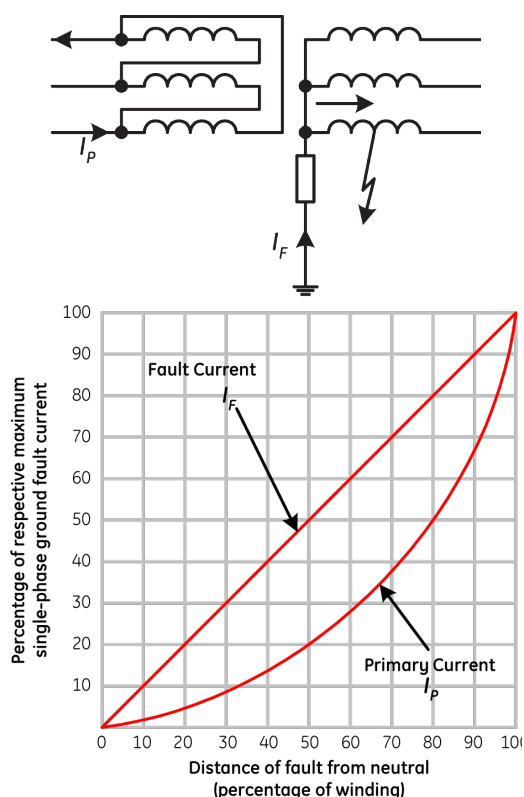
An alternative method for inrush inhibit is also available, where either current, voltage, or breaker status is used to indicate a de-energized transformer. The threshold can be lowered during energization of the transformer as indicated either by breaker contact, current or voltage sensing, and will last for a settable time delay. This allows settings of less than 20% for inrush inhibit during transformer energization.

Available in the 745.

4.3 Sensitive Ground Fault Protection to limit Transformer Damage

Differential and overcurrent protection do not provide adequate protection for wye-connected windings with grounded neutrals. Faults close to the neutral produces lesser fault current as shown by the current distribution curve. The restricted ground fault function can be used to provide differential protection for such ground faults, down to faults at 5% of the transformer winding. Restricted ground fault protection can be a low impedance differential function or a high impedance differential function. The low impedance function has the advantage to being able to precisely set the sensitivity to meet the application requirement. This sensitive protection limits the damage to the transformer to allow quicker repair. The restricted ground fault element uses adaptive restraint based on symmetrical components to provide security during external phase faults with significant CT error. This permits the function to maximize sensitivity without any time delay.

Available in the 745, T60.

4.4 Overflux Protection

Transformer overfluxing can be a result of

*   Overvoltage
*   Low system frequency

A transformer is designed to operate at or below a maximum magnetic flux density in the transformer core. Above this design limit the eddy currents in the core and nearby conductive components cause overheating which within a very short time may cause severe damage. The magnetic flux in the core is proportional to the voltage applied to the winding divided by the impedance of the winding. The flux in the core increases with either increasing voltage or decreasing frequency. During startup or shutdown of generator-connected transformers, or following a load rejection, the transformer may experience an excessive ratio of volts to hertz, that is, become overexcited. When a transformer core is overexcited, the core is operating in a non-linear magnetic region, and creates harmonic components in the exciting current. A significant amount of current at the 5th harmonic is characteristic of overexcitation.

Available in the 745, T60, and T35.

4.5 Winding hot-spot temperature protection

The transformer winding hot-spot temperature is another quantity that should be used for protection of transformers. Protection based on winding hot-spot temperature can potentially prevent short circuits and catastrophic transformer failure, as excessive winding hot-spot temperatures cause degradation and eventual failure of the winding insulation. The ambient temperature, transformer loading, and transformer design determine the winding temperature. Temperature based protection functions alarm or trip when certain temperature conditions are met.

GE Multilin relays use IEEE C57.91 compliant thermal models to calculate the winding hot-spot temperature and the loss of life of the winding insulation. The top-oil temperature may be directly measured, or calculated from the ambient temperature, load current, and transformer characteristics. In addition, the calculations may use a monthly model of ambient temperature, eliminating the need for external connections to the transformer and relay. This winding hot-spot temperature and transformer loss of life information is used in thermal overload protection to provide alarming or tripping when unacceptable degradation of the transformer winding insulation is occurring.

Available in 745, T60.

4.6 Application Capabilities

GE Multilin transformer protection relays are suitable for different transformer protection applications, including medium voltage and high voltage transformers of any size, dual secondary transformers, auto-transformers, three-winding transformers, transformers with dual-breaker terminals.

In addition, these relays are designed for both new and retrofit installations. New installations typically use wye-connected CTs, and internally compensate the measured currents for the phase shift of the protected transformer. Traditional installations may use delta-connected or wye-connected CTs that externally compensate the measured currents for the phase shift of the protected transformer. GE Multilin accommodates both methods as simple configuration settings.

Beyond these typical applications, GE Multilin transformer protection relays can be applied on more advanced applications.

4.7 Phase shift transformers

Phase shift transformers – phase shift transformers purposely introduce a variable phase shift between the primary and secondary voltage. This phase shift is not a multiple of 30 degree, but is adjustable in small increments, to allow operators to change the phase angle between parts of the power system to control power flow in the system. GE Multilin relays are successfully applied for protecting phase shifting transformers.

4.8 Split-phase autotransformers

Split-phase autotransformers – are single-phase auto-transformers connected in parallel to make a large three-phase bank. The differential protection from GE Multilin can be used to identify turn-turn faults in one of the auto-transformers without operating the entire bank.

5. Typical applications

This section highlights some typical application of GE Multilin transformer protection relays. This section is not intended as a comprehensive list of possible applications. For questions about the correct relay for a specific application, please contact GE Multilin.
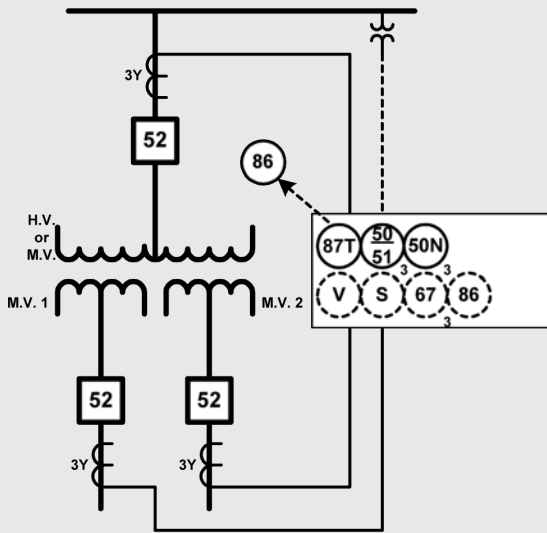

Transformers 750kVA and above, MV Windings
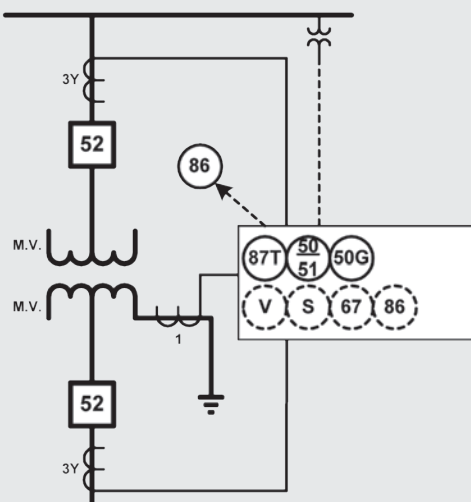
Typical Functions		Additional Functions	
87T	Differential	67	Directional overcurrent
86	Lockout auxiliary	V, S	Voltage and Power metering
50/51	Overcurrent and short circuit		
50G	Ground fault		

Functions	Typical Product Order Code
Typical Functions	745-W2-P5-G5-HI-T T35-N00-HCH-F8N-H6P-MXX-PXX-UXX-WXX T60-N00-HCH-F8N-H6P-MXX-PXX-UXX-WXX
+ Harsh Environment Option	745-W2-P5-G5-HI-T-H T35-N00-ACH-F8N-H6P-MXX-PXX-UXX-WXX T60-N00-ACH-F8N-H6P-MXX-PXX-UXX-WXX
+ Voltage and Power metering	745-W2-P5-G5-HI-T T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Directional overcurrent	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
Lockout Standalone Integrated	HEA61-A-RU-220-X2 T35-N00-HPH-F8N-H6P-MXX-P4L-UXX-WXX T60-N00-HPH-F8N-H6P-MXX-P4L-UXX-WXX

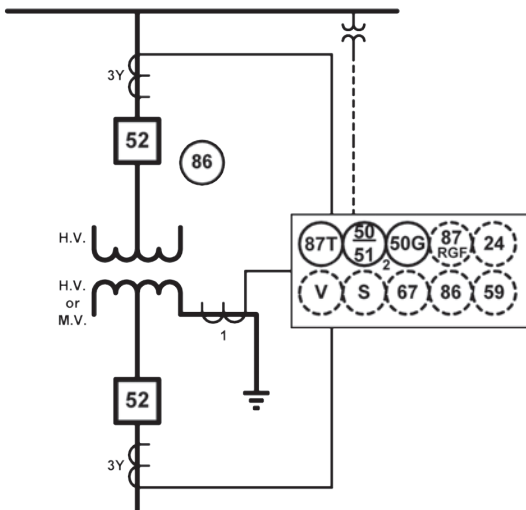## Power Transformers, Dual MV Secondary Windings

Typical Functions

87T	Differential
86	Lockout auxiliary
50/51	Overcurrent and short circuit (three windings)
50N	Neutral ground fault (three windings)

Additional Functions

67	Directional overcurrent
V, S	Voltage and Power metering

Functions	Typical Product Order Code
Typical Functions	745-W3-P5-G5-HI-T
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Harsh Environment Option	745-W3-P5-G5-HI-T-H
	T35-N00-ACH-F8L-H6P-M8N-PXX-UXX-WXX
	T60-N00-ACH-F8L-H6P-M8N-PXX-UXX-WXX
+ Voltage and Power metering	745-W3-P5-G5-HI-T
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Directional overcurrent	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
Lockout	
Standalone	HEA61-A-RU-220-X2
Integrated	T35-N00-HPH-F8L-H6P-M8N -P4L-UXX-WXX
	T60-N00-HPH-F8L-H6P-M8N -P4L-UXX-WXX

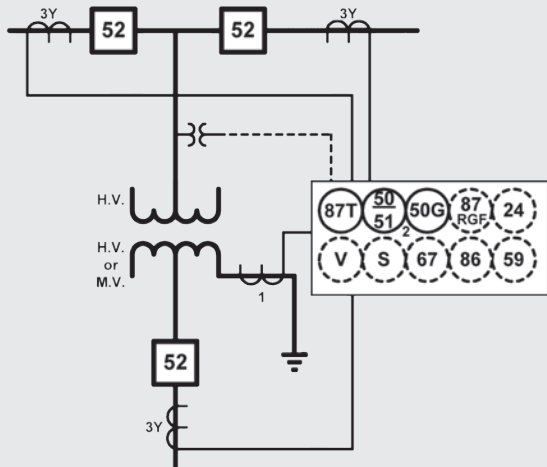## Power Transformers, HV Windings

Typical Functions

87T	Differential
86	Lockout auxiliary
50/51	Overcurrent and short circuit (both windings)
50G	Ground fault

Additional Functions

87RGF	Restricted Ground Fault
67	Directional overcurrent
24	Volts per Hertz
59	Overvoltage
V, S	Voltage and Power metering

Functions	Typical Product Order Code
Typical Functions	T60-N00-HCH-F8N-H6P-MXX-PXX-UXX-WXX
	T35-N00-HCH-F8N-H6P-MXX-PXX-UXX-WXX
	745-W2-P5-G5-HI-T
+ Voltage and Power metering	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	745-W2-P5-G5-HI-T
+ Additional Functions (87G, 67, 24, 59)	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	745-W2-P5-G5-HI-R-T
Lockout	
Standalone	HEA61-A-RU-220-X2
Integrated	T35-N00-HPH-F8N-H6P-MXX-P4L-UXX-WXX
	T60-N00-HPH-F8N-H6P-MXX-P4L-UXX-WXX

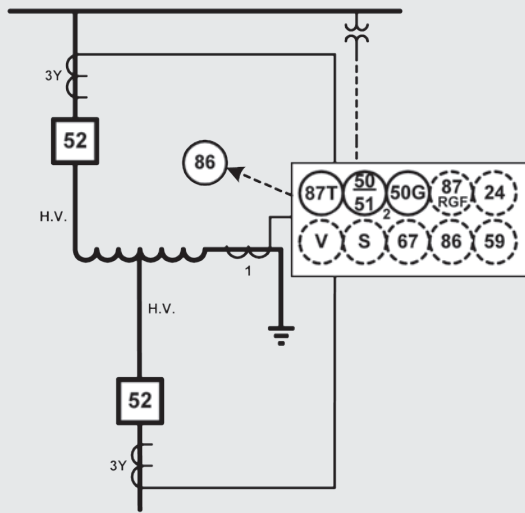## Power Transformers, HV Windings, Dual-Breaker Source

Typical Functions

87T	Differential
86	Lockout auxiliary
50/51	Overcurrent and short circuit (two windings)
50G	Ground fault

Additional Functions

87RGF	Restricted Ground Fault
67	Directional overcurrent
24	Volts per Hertz
59	Overvoltage
V, S	Voltage and Power metering

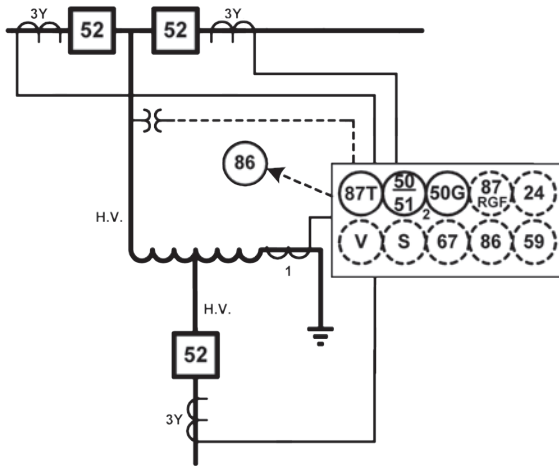| Functions	Typical Product Order Code
Typical Functions	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Voltage and Power metering	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Additional Functions	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
Lockout	
Standalone	HEA61-A-RU-220-X2
Integrated	T35-N00-HPH-F8L-H6P-M8N-P4L-UXX-WXX
	T60-N00-HPH-F8L-H6P-M8N-P4L-UXX-WXX

Auto-Transformer

Typical Functions		Additional Functions	
87T	Differential	87RGF	Restricted Ground Fault
86	Lockout auxiliary	67	Directional overcurrent
50/51	Overcurrent and short circuit (both sources)	24	Volts per Hertz
		59	Overvoltage
50G	Ground fault	V, S	Voltage and Power metering

Functions	Typical Product Order Code
Typical Functions	T60-N00-HCH-F8N-H6P-MXX-PXX-UXX-WXX
	T35-N00-HCH-F8N-H6P-MXX-PXX-UXX-WXX
+ Voltage and Power metering	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Additional Functions	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
Lockout	
Standalone	HEA61-A-RU-220-X2
Integrated	T35-N00-HPH-F8N-H6P-MXX-P4L-UXX-WXX
	T60-N00-HPH-F8N-H6P-MXX-P4L-UXX-WXX

Auto-Transformer, Dual-Breaker Terminals

Typical Functions		Additional Functions	
87T	Differential	87RGF	Restricted Ground Fault
86	Lockout auxiliary	67	Directional overcurrent
50/51	Overcurrent and short circuit (two windings)	24	Volts per Hertz
		59	Overvoltage
50G	Ground fault	V, S	Voltage and Power metering

Functions	Typical Product Order Code
Typical Functions	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Voltage and Power metering	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
+ Additional Functions	T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX
Lockout	
Standalone	HEA61-A-RU-220-X2
Integrated	T35-N00-HPH-F8L-H6P-M8N-P4L-UXX-WXX
	T60-N00-HPH-F8L-H6P-M8N-P4L-UXX-WXX

Auto with Dual-Breaker on both sides and loaded tertiary
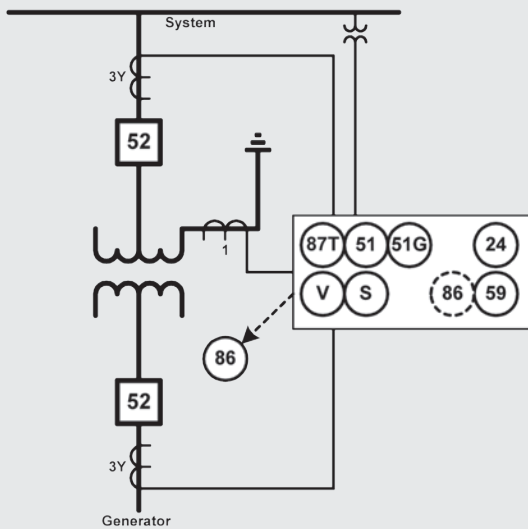

Typical Functions		Additional Functions	
87T	Differential	V, S	Voltage and Power metering
86	Lockout auxiliary		
50/51	Overcurrent and short circuit (three windings)		
50G	Ground fault		

Functions	Typical Product Order Code
Typical Functions	T35-N00-HCH-F8L-H6P-M8N-PXX-U8N-W6P
+ Voltage and Power metering	T35-N00-HCH-F8L-H6P-M8N-PXX-UXX-W6P
Lockout	
Standalone	HEA61-A-RU-220-X2
Integrated	T35-N00-HPH-F8L-H6P-M8N-P4L-U8N-W6P

Generator Step Up Transformer

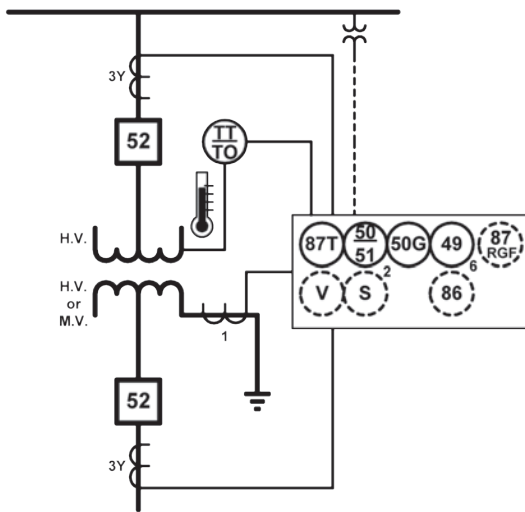| Typical Functions		Additional Functions	
87T	Differential	51G	Ground Fault
86	Lockout auxiliary	24	Volts per Hertz
51	Overcurrent and short circuit (three windings)	59	Overvoltage
		V, S	Voltage and Power metering

Functions	Typical Product Order Code
Typical Functions	**T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-WXX**
Lockout	
Standalone	**HEA61-A-RU-220-X2**
Integrated	**T60-N00-HPH-F8L-H6P-M8N-P4L-UXX-WXX**

Thermal Overload Protection

Typical Functions		Additional Functions	
87T	Differential	87RGF	Restricted Ground Fault
86	Lockout auxiliary	V, S	Voltage and Power metering
50/51	Overcurrent and short circuit (two windings)		
50G	Ground fault		
TT/TO	Top Oil Temperature, RTD or Transducer		
	Winding hot-spot temperature, loss-of-life		
49	Thermal overload protection		

Functions	Typical Product Order Code
Typical Functions	**T60-N00-HCH-F8N-H6P-MXX-PXX-UXX-W5E**
	745-W2-P5-G5-HI-L-T
+ Voltage and Power metering	**T60-N00-HCH-F8L-H6P-M8N-PXX-UXX-W5E**
	745-W2-P5-G5-HI-L-T
+ Additional Functions	**T60-N00-HCH-F8N-H6P-MXX-PXX-UXX-W5E**
	745-W2-P5-G5-HI-L-R-T
Lockout	
Standalone	**HEA61-A-RU-220-X2**
Integrated	**T60-N00-HPH-F8N-H6P-MXX-P4L-UXX-W5E**

Distribution Transformer with no load-side Circuit Breaker
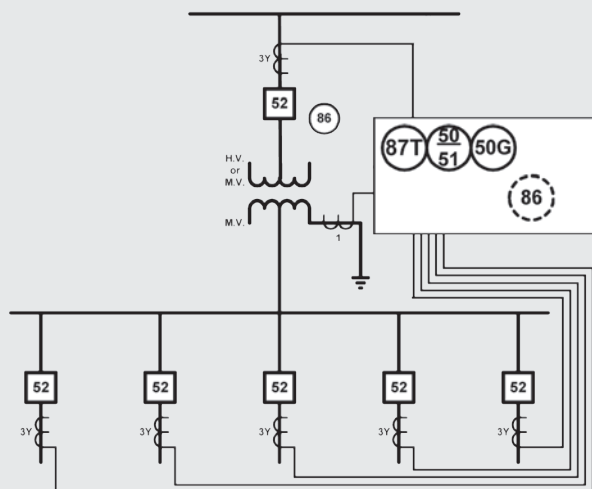
Typical Functions	
87T	Differential
86	Lockout auxiliary
51	Overcurrent and short circuit (two windings)
50G	Ground fault

Functions	Typical Product Order Code
Typical Functions	**T35-N00-HCH-F8N-H6P-M8N-PXX-U8N-WXX**
Lockout	
Standalone	**HEA61-A-RU-220-X2**
Integrated	**T35-N00-HPH-F8N-H6P-M8N-P4L-U8N-WXX**

6. References

IEEE Std C37.91-2000 IEEE Guide for Protective Relay Applications to Power Transformers

0129 -v3

All banks need protection

Today, **shunt capacitor banks** play an increasingly vital role in **blackout prevention** and supporting the growth of **distributed generation** facilities like wind farms. Protecting this equipment has historically involved complex, custom protection schemes consisting of multiple products that rarely addressed the inherent system and bank unbalance.
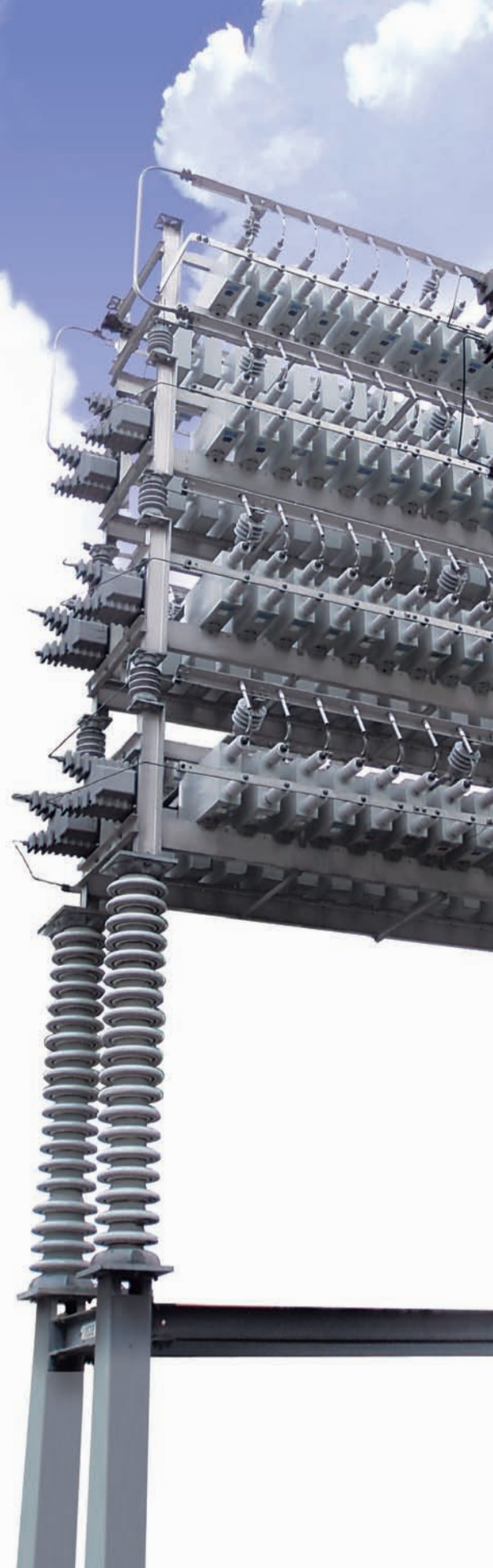
Now, there's a single universal product combining advanced **capacitor bank protection** with **automatic capacitor control**. The C70's superior protection elements provide sensitive protection with unprecedented unbalance compensation while the Automatic Voltage Regulator allows for intelligent automated cap bank control to minimize VAR consumption costs.

*GE Multilin's **C70 Capacitor Bank Protection and Control System** is based on the well-established and proven UR platform*

Multilin

Self-Adaptive Generator Protection Methods

D. Finney	B. Kasztenny	M. McClure	G. Brunello	A. LaCroix
GE Multilin	GE Multilin	GE Energy	GE Multilin	Hydro Quebec

1. Introduction

The setting of many of the functions that are used to protect synchronous generators is relatively straightforward, requiring system or machine data that is readily available to the protection engineer. However, there are occasions where the effective application of a protection function requires detailed measurement and analysis of operational data from the machine. This paper identifies two such functions: Split Phase Protection and 3rd Harmonic Neutral Undervoltage Protection and discuss the particular application issues associated with each. These functions are responsible for detection of two of the most common types of stator winding failures; inter-turn faults and ground faults. A new algorithm is presented that can respond to the influencing system conditions and automatically adapt these functions accordingly. The resulting protection schemes are more sensitive, less likely to mis-operate, and are easier to set than their conventional counterparts.

2. Interturn Faults

A hydroelectric generator is often wound with a double-layer, multi-turn winding. The winding may be a single circuit or there may be two, four, six or eight branches in parallel. Under normal operation there is very little difference in the current in each branch. However, during an internal fault, currents will circulate between the parallel branches of the winding within one phase. Split phase protection takes advantage of this characteristic by measuring the current unbalance between these parallel branches. In hydro machines a significant percentage of stator faults begin as turn-to-turn faults 0. Due to the very high effective turns-ratio between the windings and the shorted turn, inter-turn faults cause extremely high currents in the faulted loop leading to quickly progressing damage.

These faults are not detectable by the stator differential or ground fault protections since there is no difference between the currents at the output and the neutral terminals and there is no path for fault current to ground. If these faults can be detected before they evolve in to phase or ground faults then the damage to the machine and associated downtime can be greatly reduced. Therefore the split phase protection should ideally be sensitive enough to operate for a single-turn fault in the winding of the machine.

2.1 Detection Methods

There are several methods currently in use today.

Scheme A

In scheme A, a neutral point is brought out for each parallel circuit. An overcurrent element is connected between each neutral. During an inter-turn fault, a circulating current is produced in the faulted phase that is passed between the neutrals.
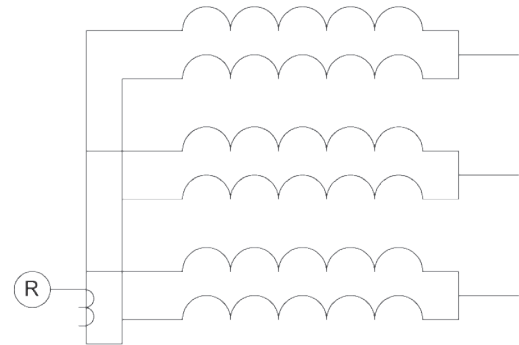

Fig 1.
Scheme A.

Scheme B

In this scheme a differential and restraint signal are derived using currents from both sides of the machine. One current represents the total current in the machine while the other is the current from a CT representing 1/2 the total current. This scheme is also known as "combined split phase and differential" or "partial longitudinal differential".
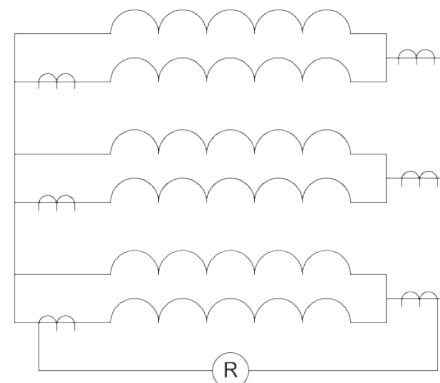

Fig 2.
Scheme B.

Scheme C

In scheme C, the currents from each parallel circuit are used to derive a differential and restraint signal. The relay has a percent slope characteristic. The restraint signal provides security against a false differential produced during an external fault while still allowing fast operation during internal faults. This scheme is sometimes known as "transverse differential".

Scheme D

The scheme shown in Figure 4 also responds to the difference between the currents in the two circuits. However, the summation is done outside the relay.
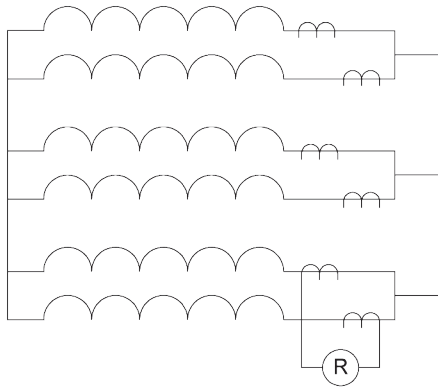
Fig 3.
Scheme C.

Therefore this method cannot derive a restraint signal. An instantaneous element using this signal must be set high enough to avoid pickup during an external fault. This will make the element relatively ineffective for detection of single-turn faults. As such this scheme usually employs a definite time or inverse time characteristic for security.
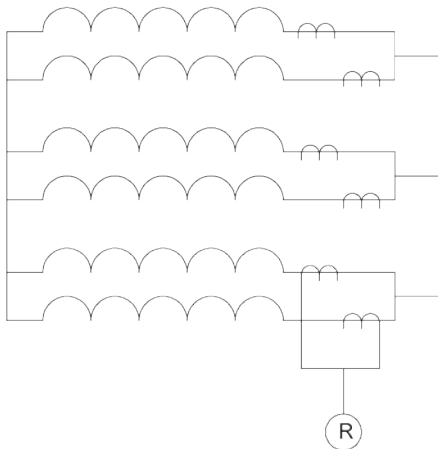

Fig 4.
Scheme D.

Scheme E

In this scheme a window-type CT is used to measure the difference between the current in each circuit, as shown in Figure 5. This method avoids the CT error issues of Scheme D.
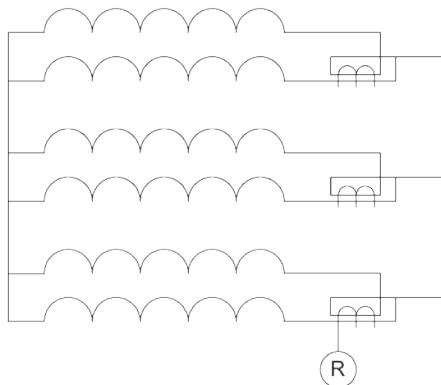

Fig 5.
Scheme E.

2.2 Characterization

Under normal operation the level of the inherent split phase current is usually less then 0.5% of the rated machine current 0. During an external fault many machines produce a transient circulating current. The magnitude of this transient can be several times larger than the steady state current and may persist for upwards of 30 cycles 0. For an internal fault, the magnitude of the circulating current corresponding to a single-turn short is dependent on several factors. These include the type of the winding (adjacent versus alternate pole) and the number of poles.

2.3 Application

A simple calculation can be carried out to approximate the circulating current due to a shorted turn as shown in the example system of Figure 6.
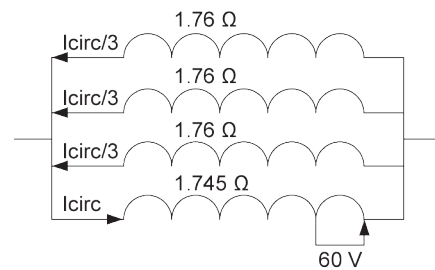

Fig 6.
Interturn Fault.

The machine in this example is rated at 65MVA and 13.8 kV. The stator winding has 4 parallel circuits, each made of 33 series coils and each coil having 4 turns. The rated current is 2700 amps. The winding impedance can be approximated by the leakage reactance (0.15 p.u in this case). Each healthy parallel branch will have 4 times the nominal impedance or 1.76 ohms. The impedance of a single turn is 0.013 ohms. The voltage across a single turn is 60 volts.

$$V_{turn} = \frac{V_{nominal}}{\sqrt{3} \quad N_{turns} \quad N_{coils}} = 60$$

$$I_{circ} = \frac{V_{turn}}{Z_{circuit} \quad Z_{turn} + \dfrac{Z_{circuit}}{N_{circuit} \quad 1}} = 26$$

This corresponds to a circulating current of about 1% of rated current.

2.4 Bypassed Coil

A failure in the winding of a machine requires its immediate removal from service until repairs have been carried out. Often the machine may be supplying critical load to the system. In this instance it is possible to carry out temporary repairs to the machine and place it back in service. These repairs typically entail isolating and bypassing the faulty coil. A machine operated under these conditions may be subject to overheating, magnetic pullover and excessive vibration requiring that it be

operated at a reduced load level. In the context of this paper, the bypassed coil can potentially have a dramatic impact on
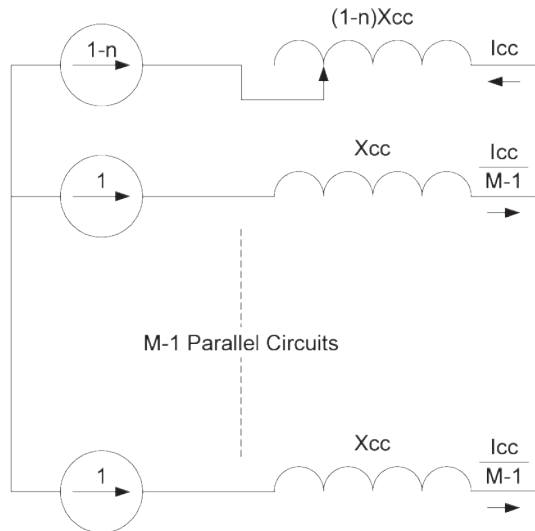

Fig 7.
Operation with a Bypassed Coil.

the inherent split phase current 0.

Figure 7 shows one phase of a machine with M parallel branches and a bypassed coil in one branch. The quantity X_{cc} can be approximated by the leakage reactance X_L 0.

The quantity n represents the number of coils bypassed expressed in per-unit. Inspection of the circuit illustrates the effect of a bypassed coil on the circulating current. It is evident that an interturn fault in a healthy branch (without a bypassed coil), can act to bring the circulating current back towards equilibrium; i.e. the fault may not necessarily translate into an increase in the split-phase current magnitude.

Figure 8 shows the split phase current in a model machine with a small portion of the stator winding bypassed in one phase. Power is displayed in per unit and split phase current in secondary amps. The bypassed winding creates a significant increase in the inherent split phase current. Additionally, the magnitude of
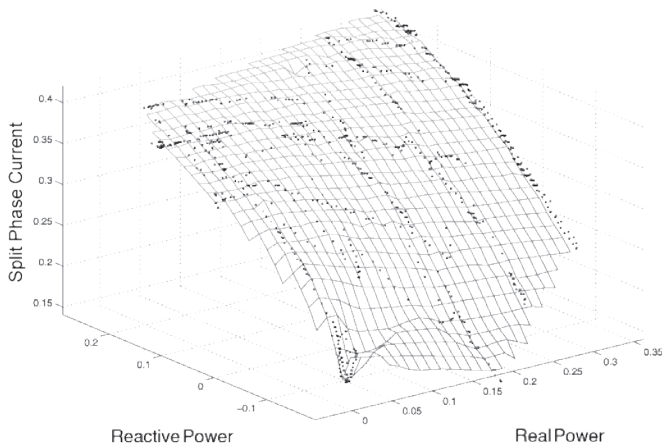

Fig 8.
Split Phase Current Measurements.

the split phase current displays a strong dependency on real and reactive power.

As a result the pickup setting of the split phase protection must

be increased to prevent false operation. This can make the function ineffective for the detection of single-turn faults.

3. Stator Ground Faults

Stator ground faults are short circuits between any of the stator windings and ground, via the iron core of the stator. Typically, when a single machine is connected to the power system through a step-up transformer, it is grounded through high impedance. As a result, the amount of the short circuit current during stator ground faults is driven by the amount of capacitive coupling in the machine and its step-up transformer. Therefore when a ground fault occurs, very small capacitive current flows making the short circuit difficult to detect.

Ground faults can be detected throughout most of the winding through the use of an overvoltage relay responding to the fundamental component of the voltage across the grounding impedance. The magnitude of this voltage is proportional to the location of the fault. Therefore, for faults at or near the neutral of the machine, this element is ineffective 0.

Little or no damage is done to the machine as a result of a ground fault close to the neutral. It does, however, prevent the overvoltage protection from detecting a second ground fault. If a second ground fault occurs, the grounding impedance does not limit the fault current. If the second ground is on the same phase it will not be detectable by the differential. The result can be potentially catastrophic damage to the machine 0. Therefore, a second method to detect faults close to the neutral and effectively prevent widespread damage to the machine is beneficial. This second method is sometimes known as 100% stator ground fault protection.
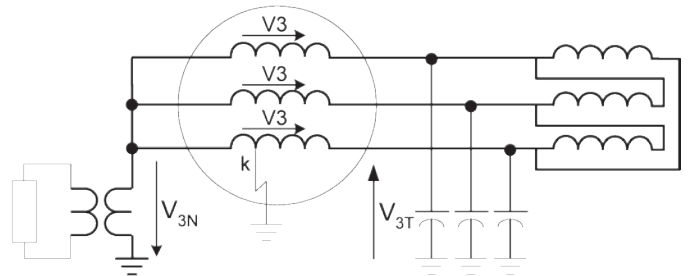

Fig 9.
Stator Ground Fault.

3.1 Detection Methods
Several techniques for 100% stator ground fault detection take advantage of the third harmonic voltage generated by the machine itself 0.

Under normal operating conditions a portion of the 3rd harmonic appears across the generator terminals and a portion appears across the grounding impedance as shown by the green line in Figure 10. For a fault at k, the distribution of the third shifts to the red line. This causes the third harmonic at the neutral to decrease and the third harmonic at the terminals to increase.

If the third harmonic can be measured both at the generator neutral and at the terminals, then a differential scheme can
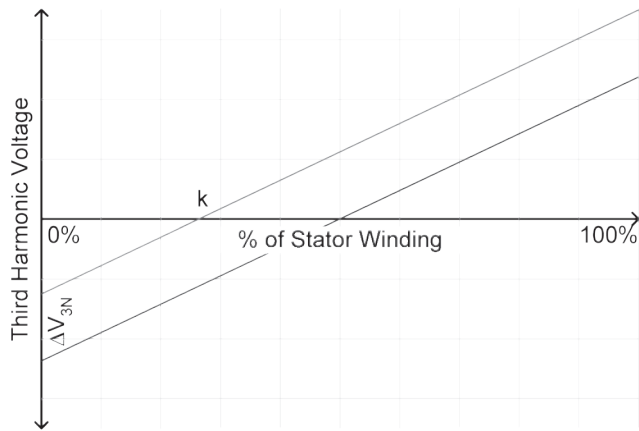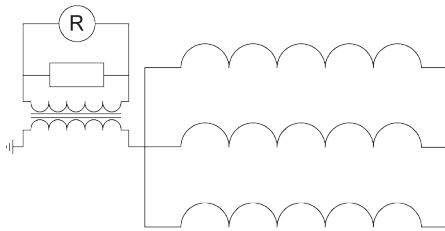
Fig 10.
Third Harmonic Distribution.

Fig 11.
Neutral Undervoltage Scheme.

be applied 0. This scheme is less sensitive to variations in the third harmonic due to machine loading. However, if the VT connection does not permit measurement of the third harmonic at the generator terminal end 0, comparison of the neutral and terminal end third harmonic signatures is impossible, then only the third harmonic neutral undervoltage element may be applied.

The third harmonic undervoltage element uses the voltage that forms across the high impedance ground, which is connected to the neutral point of the generator unless a better path to ground is presented. Figure 12 is an example of the third harmonic voltage measured at the neutral of a generator at various levels of real and reactive loading. Power is displayed in primary units and third harmonic voltage is displayed in secondary volts. During a ground fault close to the generator neutral the third
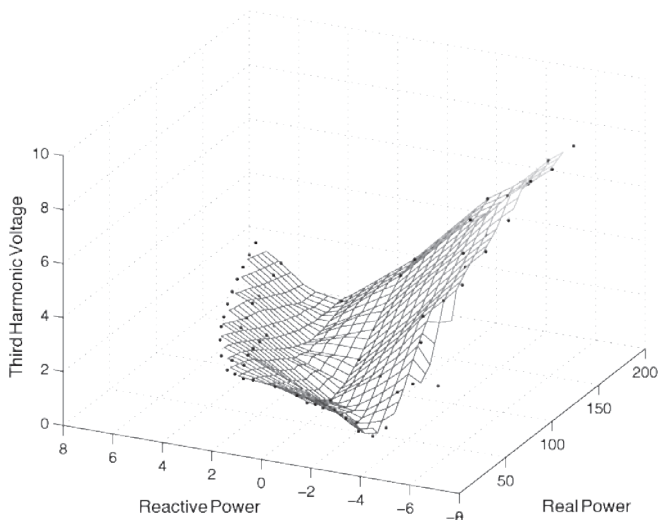
harmonic voltage will decrease or drop to zero.

In the scheme of Figure 11, a neutral voltage is measured from the machine neutral point. During a stator ground fault, the third harmonic will flow into the ground fault, shunting the neutral grounding path, and the measurement of neutral voltage will drop to or near zero.

3.2 Characterization

The characteristic of the third harmonic varies considerably between different machine designs; it can also vary considerably between machines of the same design due to manufacturing variation. Under normal operation the level of the third harmonic neutral voltage can vary considerably based upon machine output (MW), power factor (PF) and machine voltage (kV).

In order to provide optimum protection for the machine, the complete third harmonic characteristic must be found and the setting should be calculated based on this data. Data must be collected and then plotted with output (MW) along the X-axis and third harmonic neutral voltage (V) along the Y-axis as shown in Figure 13.

Once this data is plotted an appropriate tripping voltage should be determined. It should be significantly high such that the protection will function, even when the fault is further up on the winding. The setting must also allow enough margin to allow for variation and errors in the data collection and input accuracy.

A power blocking value should be derived so that it complements the tripping voltage. The local minimums in the third harmonic characteristic should be blocked allowing the highest possible tripping voltage.

There are several options for setting this function.

3.3 Type Testing

A simple method of setting this function utilizes the data from type tests for machines of the same design. Electrical machines of the same design and manufacture can be type tested and a standard set point can be calculated and used. This provides the easiest solution however it is the least effective and can provide less protection or lead to nuisance tripping.

3.4 Site Testing

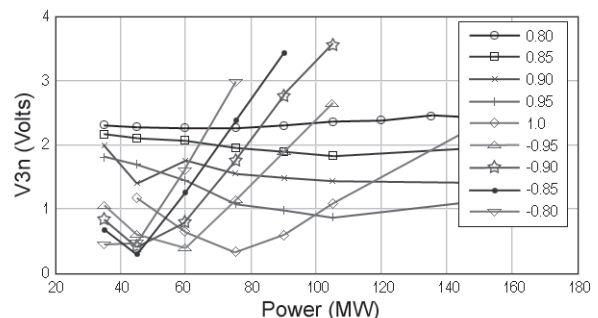The setting can be derived by taking site data for each machine

Fig 12.
Third Harmonic Voltage Characteristic.

Fig 13.
Third Harmonic Neutral Voltage Data.

Self-Adaptive Generator Protection Methods

by running the machine through the range of power output and power factor. Taking data at regular intervals will allow for a sufficiently accurate setting to allow for protection while keeping from false tripping. This method provides good protection but is more expensive than type tests and still allows the opportunity for data collection errors. An example of the data collected during a site test is shown in Figure 13.

3.5 Electronic Data Collection

If a data logger with sufficient memory exists in the applied protective relay 0, data logging can be used to collect operating data over the operating time. This data can be extracted from the data logger and used to calculate the setting. This method provides much more accurate characterization of the third harmonic, however the data may not cover the entire operating region. If the machine has not operated in those regions the protection setting decision may be made with incomplete data, which could lead to nuisance tripping or insufficient protection.

4. Self-Adaptive Protection Principles

The previous sections describe the deviation that can sometimes occur in the operating signals of the split phase and 3rd harmonic undervoltage element, as a result of active and reactive loading of the machine and the resulting problems relating to setting selection. It is proposed that for both functions a method could be derived to automatically adapt to these variables.

The method would measure and log the variations in the operating quantity over time in order to learn the characteristics under various loading conditions and operate based on a departure from this characteristic in order to protect the machine.

Implemented in a microprocessor-based device, data collection would entail sampling the voltages and currents and the operating quantities, filtering digitally, extracting magnitudes/angles using a standard Fourier algorithm, and calculating active and reactive quantities from these.

The method would allow for the protection to become active as soon as the data has been collected. The function could be proactively enabled and disabled to protect for operating conditions where sufficient operation data has been collected and block for operating conditions where insufficient data has been collected.

The function would require a security margin to account for measurement errors.

A best-fit curve could be calculated to approximate the operating characteristic; there are several methods for forming this function. This method would require recalculation of the curve each time data is collected and would be very processor intensive.

Alternately, the operating characteristic could be approximated by an array of data points stored to create a mesh of operating signal values spaced equally over the active-reactive power region. This method requires more memory to store the data but is less processor-intensive.
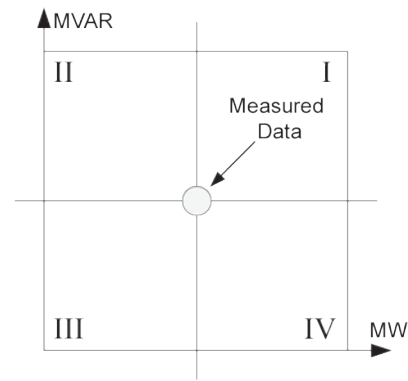

Fig 14.
Operating Data Array.

Data would be collected whenever the machine is in operation. The data would be used to update the array holding the operating data for the machine. Since the array consists of a finite number of elements, the measured value of the operating signal data would not usually correspond exactly to a point in the array (points 1-4 in Figure 14).

Therefore, either the point closest to the measured value could be updated or all four adjacent points could be updated simultaneously.

Before the data could be used for fault detection the data must be validated. This could be a manual operation – the data could be downloaded and analyzed. If satisfactory the function could then be placed in-service.

Alternately, the validation of the data could be automated. In such a scheme, a test could be carried out on the data to determine whether or not it is changing dramatically between successive samples. An additional test would be to examine the smoothness of the characteristic over successive data points.

An important consideration is the number of points in the array required for an accurate representation of the data. The factors influencing this determination include the smoothness of the operating characteristic, the method used to interpolate between points in the array and the accuracy required by the function.

Once the data has been validated it may be used for fault detection. Again, it is unlikely that the measured value of P and Q will correspond to a point in the array.

An expected operating value must therefore be calculated for each value of P and Q. Since this function is adaptive the value must be calculated in real time.

Terminal voltage can have a significant effect on the quiescent value of the operating signal. The signal can be similarly affected during other system disturbances. Therefore it is important to inhibit learning during these periods. This can be achieved by monitoring of the positive sequence voltage and current. Learning is inhibited if the positive sequence voltage is lower than its nominal range. Learning is also inhibited when the positive sequence current is greater than its nominal value. Additionally, some machines may exhibit a significant difference in the operating signal between the offline and online state. In such cases, learning may also be supervised by breaker position. Once system conditions return to normal for a definite

period, normal learning can resume. Similar supervision can be applied in the tripping mode.

5. Development of Adaptive Algorithms

As explained in the previous section adaptive algorithms in this application consist of two parts. First, a learning procedure is required to establish the operate/restraint surface based on the measured data over longer periods of time. Second, an operate logic is required to use the learned surface for tripping at a given time.

This section presents practical ways of implementing such algorithm. The equations are derived for two-dimensional situations, i.e. when a single operating quantity depends on two variables, but can be easily extended onto generalized multi-dimensional cases.

5.1 Learning Procedure

With reference to Figure 15, an operating quantity X under non-fault conditions in a function of two variables, P and Q. In our
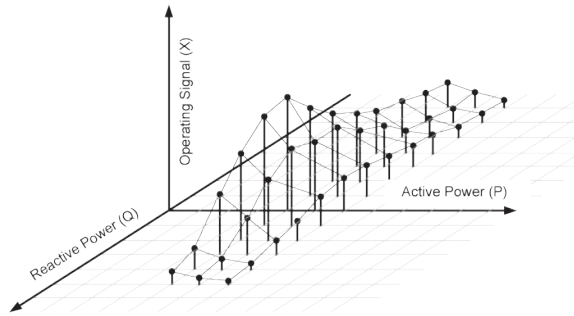

Fig 15.
Normal Operation Surface.

application P and Q are active and reactive power in the export direction, and X is the window CT current magnitude or angle in case of split-phase protection, and the third harmonic voltage magnitude in the case of stator ground fault protection.

The normal operation surface is represented by a finite amount of points in the form of a grid. Assuming the same grid size for the active and reactive power, Δ, the grid coordinates are:

$$P_i = \Delta \cdot i, \quad i = 0 \dots N_{max} \tag{1a}$$

$$Q_j = \Delta \cdot j, \quad j = -M_{max} \dots M_{max} \tag{1b}$$

Note that the active power is assumed positive, as there is no need to keep this method operational under the short periods of abnormal reverse-power operation of the machine. If needed, the implementation can easily be extended to cover all four quadrants of power.

During normal or abnormal operation of the machine, the measuring unit of the relay, returns the following operating point:

$$(X, P, Q) \tag{2}$$

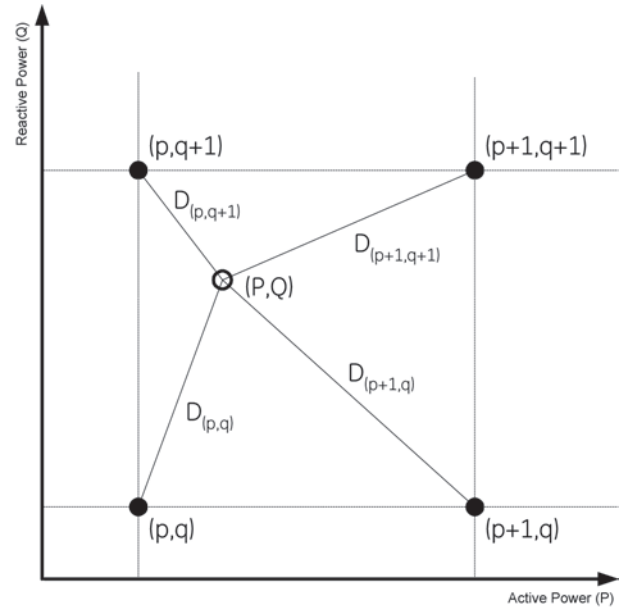First, this point must be related to the finite grid representing the operate/restraint surface:

Fig 16.
Calculation of Distances.

$$p = floor\left(\frac{P}{\Delta}\right) \tag{3a}$$

$$q = floor\left(\frac{Q}{\Delta}\right) \tag{3b}$$

Where floor stands for rounding down to the nearest integer.

The operating point is located between the following four corners of the grid (Figure 16):

$$(p,q)(p,q+1)(p+1,q+1)(p+1,q) \tag{4}$$

During the learning phase, the value of X shall be used to adjust all four corners surrounding the operating point. Different approaches can be used.

In one method, all four points are treated equally and use the same value to adjust the value of the learned X. For example:

$$X_{(p,q)NEW} = (1-\alpha) \cdot X_{(p,q)OLD} + \alpha \cdot X \tag{5a}$$

In the above, a smoothing filter is used for extra security. Only a small fraction of the measurement (α) is added to the previous value. In this way the sought value at the (p, q) point of the grid reaches its steady state asymptotically, and the value of α controls the speed of learning. The higher the α, the faster will be the convergence.

Similar equations are used to adjust the other three corners around the measuring point:

$$X_{(p,q+1)NEW} = (1-\alpha) \cdot X_{(p,q+1)OLD} + \alpha \cdot X \tag{5b}$$

$$X_{(p+1,q+1)NEW} = (1-\alpha) \cdot X_{(p+1,q+1)OLD} + \alpha \cdot X \tag{5c}$$

$$X_{(p+1,q)NEW} = (1-\alpha) \cdot X_{(p+1,q)OLD} + \alpha \cdot X \tag{5d}$$

In another method, the closer the operating point to a given point of the grid, the higher the impact on the learned value for that point of the grid. This can be accomplished using the following equations for learning.

First, the relative distances between the operating point and the four corners are calculated:

$$D_{(p,q)} = \frac{(p \cdot \Delta - P)^2 + (q \cdot \Delta - Q)^2}{2 \cdot \Delta^2} \tag{6a}$$

$$D_{(p,q+1)} = \frac{(p \cdot \Delta - P)^2 + (q \cdot \Delta + \Delta - Q)^2}{2 \cdot \Delta^2} \tag{6b}$$

$$D_{(p+1,q+1)} = \frac{(p \cdot \Delta + \Delta - P)^2 + (q \cdot \Delta + \Delta - Q)^2}{2 \cdot \Delta^2} \tag{6c}$$

$$D_{(p+1,q)} = \frac{(p \cdot \Delta + \Delta - P)^2 + (q \cdot \Delta - Q)^2}{2 \cdot \Delta^2} \tag{6d}$$

These distances can be used to speed up the learning for corners located closer to the operating point:

$$\begin{aligned} X_{(p,q)NEW} &= (1 - \alpha \cdot (1 - D_{(p,q)})) \cdot X_{(p,q)OLD} \\ &\quad + \alpha \cdot (1 - D_{(p,q)}) \cdot X \end{aligned} \tag{7a}$$

$$\begin{aligned} X_{(p,q+1)NEW} &= (1 - \alpha \cdot (1 - D_{(p,q+1)})) \cdot X_{(p,q+1)OLD} \\ &\quad + \alpha \cdot (1 - D_{(p,q+1)}) \cdot X \end{aligned} \tag{7b}$$

$$\begin{aligned} X_{(p+1,q+1)NEW} &= (1 - \alpha \cdot (1 - D_{(p+1,q+1)})) \cdot X_{(p+1,q+1)OLD)} \\ &\quad + \alpha \cdot (1 - D_{(p+1,q+1)}) \cdot X \end{aligned} \tag{7c}$$

$$\begin{aligned} X_{(p+1,q)NEW} &= (1 - \alpha \cdot (1 - D_{(p+1,q)})) \cdot X_{(p+1,q)OLD} \\ &\quad + \alpha \cdot (1 - D_{(p+1,q)}) \cdot X \end{aligned} \tag{7d}$$

Version (7) has an advantage over version (5) when the operating point lingers at the border line between two different segments of the grid – it provides smooth transition between training one set of point versus a different set of points on the grid.

Equations (5) and (7) average the data when forming the operate/restraint surface by means of exponential convergence. A separate check must be designed to decide if a given value learned in the process is final and could be trusted, i.e. used by the operating logic.

Two criteria are used to decide if a given point is properly trained.

First, it is checked if the update process as dictated by equation (5) or (7) stops changing the value. This is determined by checking the increment after the update takes place. For example, when using form (7) one checks:

$$FLG_{1(p,q)} = \left| X_{(p,q)NEW} - X_{(p,q)OLD} \right| < \beta \cdot X_{(p,q)NEW} \tag{8}$$

Where ▯ is an arbitrary value expressing the percentage difference that identifies the steady state is being reached.

The above flag is calculated each time a given point on the grid is updated as a part of the learning procedure that is for all four points surrounding the operating point.

Second, it is checked with the surface emerging in response to learning is smooth. This is determined by checking differences between the surrounding points on the grid:

$$FLG_{2(p,q)} = \left| X_{(p,q)} - X_{(p-1,q)} \right| < \delta \cdot X_{(p,q)} \ \& \ \dots$$

$$\dots \& \left| X_{(p,q)} - X_{(p+1,q)} \right| < \delta \cdot X_{(p,q)} \ \& \ \dots$$

$$\dots \& \left| X_{(p,q)} - X_{(p,q-1)} \right| < \delta \cdot X_{(p,q)} \ \& \ \dots$$

$$\dots \& \left| X_{(p,q)} - X_{(p,q+1)} \right| < \delta \cdot X_{(p,q)} \tag{9}$$

Where ▯ is an arbitrary factor. Equation (9) takes exception for the points on the outer border of the grid – these points have only three, not four, neighboring points.

For a given point on the grid (p, q) to be considered trained, both the flags (8) and (9) must be asserted.

The learning procedure can be summarized as follows:

1. Take the measurement of the operating point (equation (2).

2. Calculate the coordinates of the grid (equation (3).

3. Update the four corners of the grid surrounding the operating point (equations (6) and (7).

4. Calculate the first validity flag for the four updated points (equation (8).

5. Calculate the second validity flag for the four updated points and their neighbors (equation (9).

6. Update the validity flags for the affected points on the grid.

6. Simulation Results

Figures 17-21, illustrate the learning procedure using an arbitrary surface. In this example the operating quantity is given by the following equation:

$$X = P \cdot e^{P^2 + Q^2} \tag{10}$$

For the third harmonic undervoltage function the following design constants are selected:

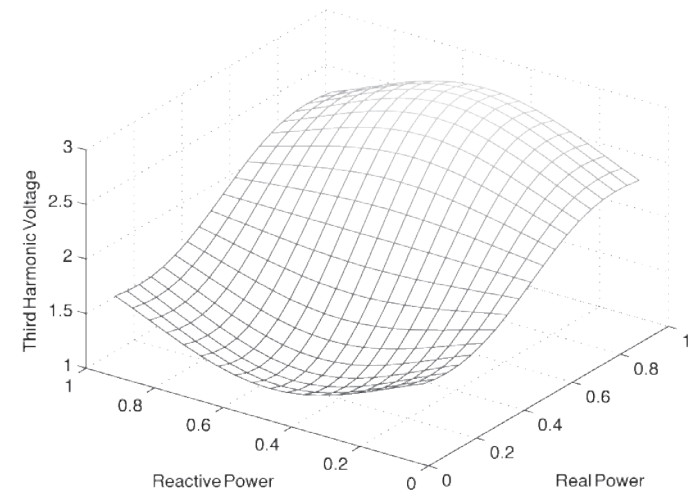$$\Delta = 0.05 pu, \quad N_{max} = 25, \quad M_{max} = 25$$

Fig 17.
Simulated 3rd Harmonic Characteristic.

$\alpha = 0.05, \quad \beta = 0.03, \quad \delta = 0.03$

For the split phase function the following design constants are selected for both the current magnitude and angle:

$\Delta = 0.125pu, \quad N_{max} = 10, \quad M_{max} = 10$

$\alpha = 0.05, \quad \beta = 0.03, \quad \delta = 0.03$

The above means the (P, Q) grid stretches as follows (0,1.25pu) for the active, and the reactive power.

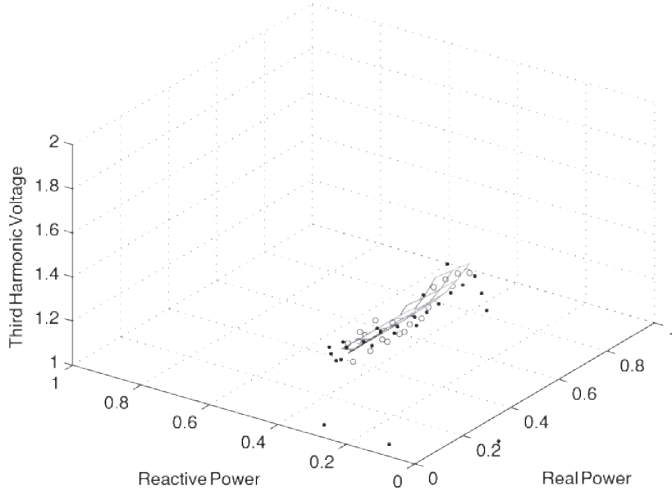Figure 17 presents function (10). This is the target function that should be learned by the procedure.

Fig 18.
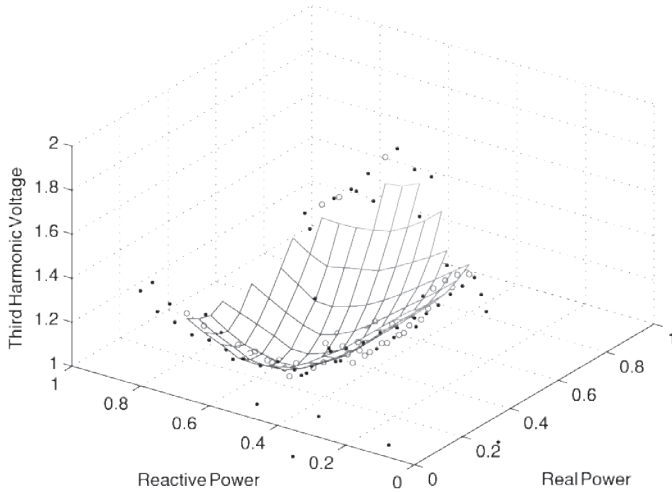*Learned Data at 1.7 Hr at 1 Sample/Sec.*

Fig 19.
Learned Data at 3.4 Hr at 1 Sample/Sec.

During the training, the operating point was varied randomly to wander within the assumed (P, Q) space. For each (P, Q) pair, the X value was calculated per equation (10), thus creating the measured operating point per equation (2). This operating point was injected into the learning algorithm.

Figures 18 and 19 present the shape of the operate/restraint surface at various stages of the learning.

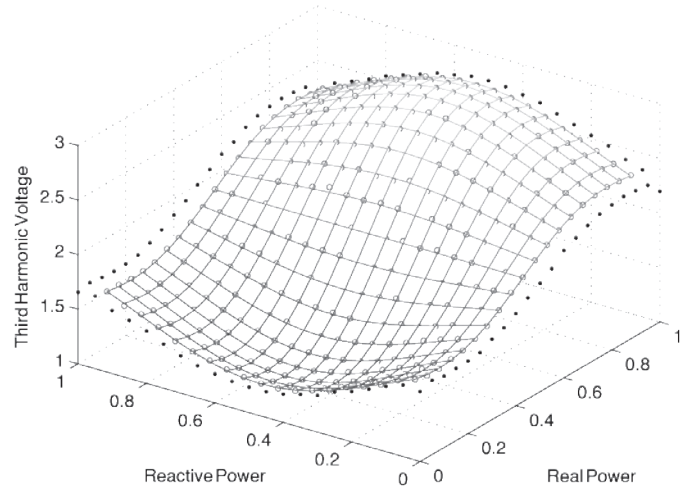These plots display the validity flags for the points on the grid.

Fig 20.
Final Learned Data.

• - "not learned" points of the surface.

○ - "learned" points of the surface.

Figure 20 shows the final learned surface at the end of the process. This shape is identical with the assumed model of the process (10), proving the learning procedure is stable and capable of re-creating the process.

7. Tripping Logic

Before the learned surface can be used to detect sudden changes and be used for tripping, the validity of the learned points on the (P, Q) grid needs to be verified. With reference to Figure 16, a given measurement point is approximated by four surrounding corners on the grid. Operation (3) is executed as a part of the tripping logic to obtain the grid coordinates. All four corners (p, q), (p, q+1), (p+1,q+1), (p+1,q) must be valid in order to proceed.

When valid, the four corners are used to interpolate the expected value of the operating signal. A weighted average can be used for this approximation:

$$D = D_{(p,q)} + D_{(p,q+1)} + D_{(p+1,q+1)} + D_{(p+1,q)} \quad (11a)$$

$$X_{EXPECTED} = \frac{1}{D}\left(X_{(p,q)} \cdot D_{(p,q)} + X_{(p,q+1)} \cdot D_{(p,q+1)} + \ldots \right.$$
$$\left. \ldots + X_{(p+1,q+1)} \cdot D_{(p+1,q+1)} + X_{(p+1,q)} \cdot D_{(p+1,q)}\right) \quad (11b)$$

Where the four distances are calculated for a given value of X using equations (6).

The tripping logic checks for differences between the expected and actual values.

The third harmonic undervoltage function operates if:

$$V_{3N} < X_{EXPECTED} - \Omega \quad (12)$$

Where Ω is a security margin.

The split-phase protection operates if

$$\left| I_{SP} - \left| X1_{EXPECTED} \right| \angle X2_{EXPECTED} \right| > \Pi \quad (13)$$
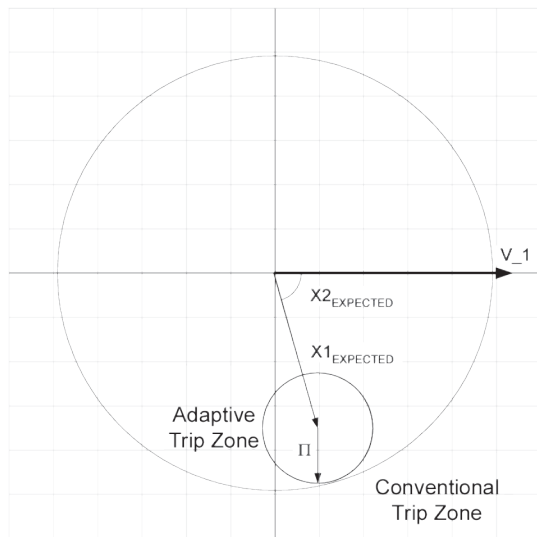
Fig 21.
Adaptive Split Phase Function.

Where $\prod$ is a security margin. The characteristic for the split phase function is illustrated in Figure 21.

In the above operating equations the security margins can be expressed as a fixed values, or as percentages of the expected value, or both in a combination.

Separate learning procedures are executed for the third harmonic undervoltage function, and for each phase of the split phase overcurrent function.

In a practical device it will be necessary to export and import learned data if, for instance the protective device is replaced. Also it will be necessary to signal to the algorithm that a repair has been carried out and it is necessary to re-evaluate the learned data.

8. Conclusion

In the area of generator protection the current state of microprocessor-based technology presents opportunities to overcome the limitations of conventional protection schemes. This paper has focused on two candidates: split phase protection and third harmonic undervoltage. It has been shown that these functions can present challenges for effective application. It has also been demonstrated that adaptive algorithms can be designed to circumvent these problems and can result in a function that is more sensitive over a wider range of operation.

Moving forward the authors intend to prototype the algorithms in a microprocessor-based device and carry out field trials on in-service machines in order to validate the methods, optimize the design constants used in the algorithm, and identify possible opportunities for improvement.

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Distance Relay Fundamentals

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1. Introduction

Distance functions have been in use for many years and have progressed from the original electromechanical types through analog types and now up to digital types of functions. The purpose of this paper is to discuss fundamental features of the three types of functions and possible problems that may be encountered in their design and application.

2. MHO Functions

Simple MHO Function

A simple mho distance function, with a reach of Z ohms, is shown in Figure 1. This diagram is exactly equal to an R-X diagram except that all of the impedance vectors have been operated on by the current I. The mho function uses the current and voltage measured at the relay to determine if the apparent impedance plots within the mho characteristic. The determination is made by comparing the angle between the operating quantity (IZ - V) and the polarizing quantity (V, where $V = IZ_f$). If the angle is less than or equal to 90°, then the fault impedance Z_f plots within the characteristic, and the function will produce an output. If the angle is greater than 90°, then Z_f falls outside of the characteristic and no output will be produced. Assume that the angle of maximum reach (☐) and the angle of Z_L (☐) are equal. On that basis, the conditions shown in 2 will be obtained. The key point to note in this phasor analysis (a convenient way to view relay performance) is the magnitude of the IZ - V (V_{op}) phasor and its relationship to the V (V_{pol}) phasor. Operation will occur whenever V_{op} and V_{pol} phasors are within 90° of each other and provided both Vop and Vpol are greater than the minimum values established by the sensitivity of the relay design. For the balance point fault, IZ-V is zero, therefore no operation occurs, which is expected. For an internal fault, IZ -V and V are in phase, therefore the function operates as expected. For the external
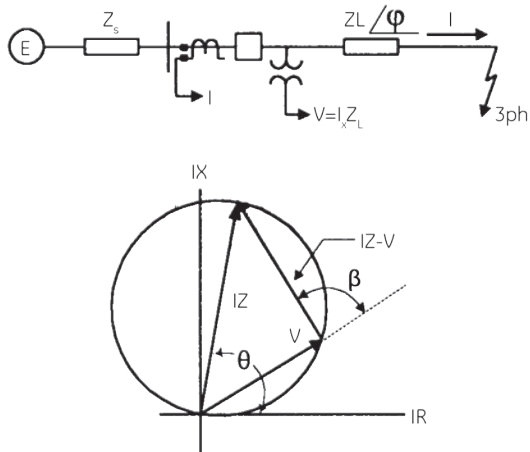
fault, operation does not occur because IZ-V and V are 180° out of phase. Observe that for the balance point fault, the V is exactly equal to IZ. This is true for the three-phase fault shown (also for a phase-to-phase fault) and for a phase distance function only. For a ground distance function, this will only be true if the function includes zero sequence current compensation as discussed later in this paper.

The polarizing quantity for this simple mho distance function is simply equal to the fault voltage V, therefore the function is said to be self-polarized and has the simple characteristic shown in Figure 1. In general, a voltage different than the fault voltage is used to polarize the function and this will have an effect on the characteristic.

a. Balance Point Fault, V=IZ   b. Internal Fault, V<IZ

b. External Fault, V>IZ
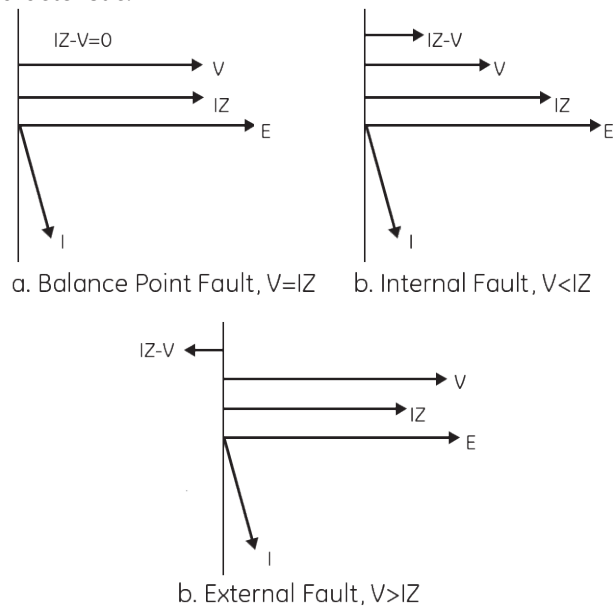
Fig 2.
Phasor Analysis of Operation of Simple MHO Function.

Polarizing Quantity

A number of polarizing quantities have been used in developing phase and ground mho distance functions. Following are some of the more commonly used:

- self-polarized (V_a for Phase A function, V_{ab} for the Phase AB function, etc.)

- positive Sequence Voltage (V_{a1} for Phase A function, V_{ab1} for Phase AB function, etc.)

- quadrature Voltage (V_{bc} shifted leading 90° for Phase A function)

- median (midpoint of V_{bc} to V_a for Phase A function)

- leading phase (V_c shifted leading 240° for Phase A function)

Fig 1.
Simple MHO Function.

$$Z_S = (Z_{S1})/2$$
$$V_{pol} = V_{ab1}$$

a. Mho Phase Distance (Phases AB)

$$Z_S = (Z_{S2} ++ Z_{S0})/3$$
$$V_{pol} = V_{a1}$$

b. Mho Ground Distance (Phases A)

Fig 3.
Variable MHO Characteristic (positive sequence voltage polarized).

An mho function that is other than self-polarized is often described as being cross-polarized. No attempt will be made here to describe the effect of all types of cross-polarization. Suffice it to say that cross-polarization will still result in a circular characteristic, but one that may also swivel and vary in size dependent on system conditions.
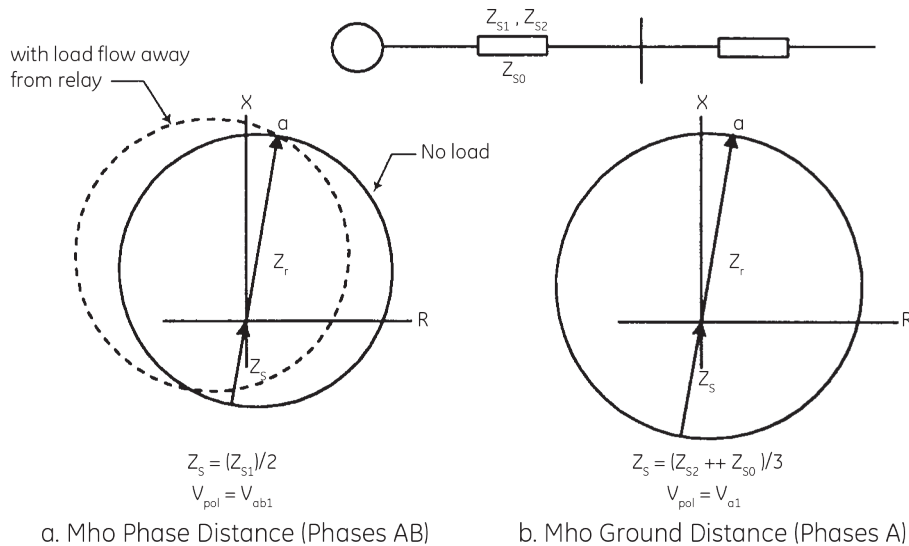
For example, consider the case of a distance function that uses positive sequence voltage as the polarizing signal. The characteristics for a phase distance function and a ground distance function that use positive sequence voltage polarization are shown in Figure 3a and 3b are drawn for a phase to-phase and phase-to-ground fault respectively. As can be seen, these characteristics are not fixed in size, but will vary proportionately with the source impedance directly behind the function. Load flow [1] will cause the characteristic to swivel to the left (as shown) or to the right relative to the forward reach (point a), with the amount and direction of the swivel depending on the magnitude and the direction of load flow. The effect of the swivel and variability is to accommodate more resistance in the fault (to be discussed later) than would be obtained with a self-polarized mho function. Note that the plots of Figure 3 are for faults in the forward (tripping) direction. The function will not operate for an inductive fault behind them.

All mho distance functions require voltage in order to operate. For a fault right at the relay location, the voltage will be very small (approaching zero for a bolted fault), and a self-polarized mho function may not operate for such a fault, whereas a cross-polarized function will, except for a three-phase fault. For a three-phase close-in fault, all three voltages will be very small, therefore operation of any of the cross-polarized functions will be jeopardized because there will be very little, or no voltage available to develop the polarizing quantity. To overcome this deficiency, memory is added to the polarizing circuits.

Memory Action

In electro-mechanical and analog type mho functions, memory is accomplished through the use of tuned filter circuits. The circuits are tuned to the power system frequency and in effect remember the voltage seen by the function prior to the fault.

The filters are designed with a factor sufficient to allow mho function operation until the memory dies away; i.e., during the filter ring-down period typical filter outputs lasts in the order of three to five cycles of power system frequency, which is sufficiently long to allow the function to produce an output and so initiate zone 1 direct tripping or high speed pilot tripping. Time-delayed backup tripping could not be counted on for close-in faults however, because the filter ring-down time is generally not long enough to allow the backup timers to time out.

Memory in digitally implemented mho functions is accomplished using digital techniques, consequently there is no ring-down as with analog filters, and the remembered voltage can be held for any desired period of time. If the remembered time is set long enough, then time-delayed backup tripping can also be initiated for close-in faults. In general, It is best to allow the voltage applied to a mho function to adapt to the system voltage as soon as possible following a system disturbance so that the function is in step with the system when the disturbance is cleared. For example, consider a fault of sufficient duration so that the voltage at the relay may have shifted considerably as the result of a system swing caused by the fault. If the memory is set long enough such that the function is still sensing the voltage prior to the disturbance when the disturbance is cleared, then problems may be introduced. To avoid any possible problems, memory time should be kept to a minimum, or an adaptive memory can be used. An adaptive memory can be implemented by sensing the voltage at the time of the fault. If the voltage is less than a set value (10 percent for example) then the voltage prior to the fault will be remembered and used by the function until the fault is cleared as indicated by reset of the function. On the other hand, if the voltage is greater than the set value, then the voltage prior to the fault will be remembered for a short period of time (5 cycles for example) after which the voltage applied to the function will adapt to the actual voltage. In this way, time-delayed backup protection can be implemented for close-in faults while allowing the function to change to the system voltage with minimum time delay for all other faults.
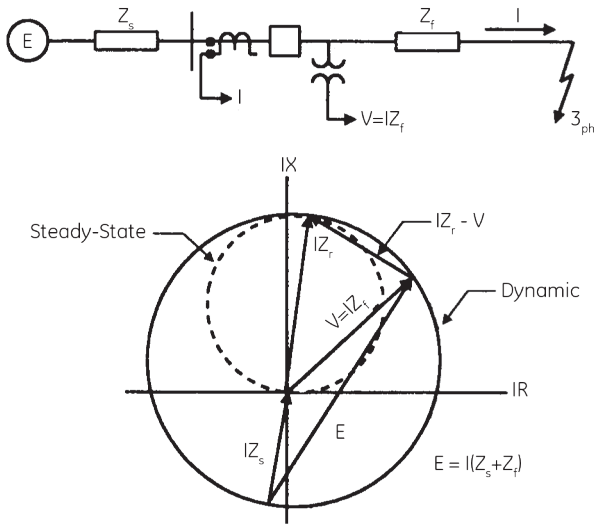
Fig 4.
Dynamic Response.

The result of memory action is to produce a dynamic (time varying) response from the function that is different from the steady-state response. This results in the dynamic and steady-state characteristics shown in Figure 4 (remember that this diagram is the same as an R-X diagram except for the inclusion of the current I). This difference in response comes about because the function is using a different polarizing voltage during the memory period as opposed to that used steady-state. The dynamic characteristic lasts as long as the memory time. If the memory changes with time, as would happen with an analog filter, then the dynamic characteristic changes in time as the remembered voltage changes to the steady-state value. In terms of Figure 4, the function produces the dynamic characteristic using the remembered voltage, E, and then changes to the actual voltage, V to produce the steady-state characteristic. The function in Figure 4 would theoretically operate dynamically because the fault impedance (Z_f) just falls on the characteristic, but it would not operate steady-state because Z_f falls outside of the steady-state characteristic.

Polarizing Voltage Sensitivity

All distance functions require a finite amount of voltage in order to operate. Exactly how much is required is a measure of the sensitivity of the function and is determined by the type and design of the function.

The voltage polarizing sensitivity is set by design and if the voltage at the relay falls below that level then the function will not produce an output except by memory action. If there is no memory, then there will be no output. If the memory is finite in duration, then the output will last just as long as the memory. If adaptive memory is used, then the output will last until the function resets following clearing of the disturbance that initiated operation of the function.

It is possible to design the relay input circuits to sense very low magnitudes of voltage: however, there are good reasons for placing sensitivity limits on the voltage polarizing circuits, the primary purpose being to prevent operation for a fault directly behind the function [2]. Consider the system shown in Figure 5. For a three-phase fault at the location shown, resistance in the arc produces a voltage at the relay that is generally accepted to

be approximately 5 percent or less of the power system voltage [3, 4]. The effect of load flow is to cause a shift in this voltage relative to the relay current because the relay current (Ir) and the total fault current (I_f) are out of phase with each other. The shift in phase in the voltage is more pronounced as the impedance, Z_t, gets larger relative to the impedance, Z_s.
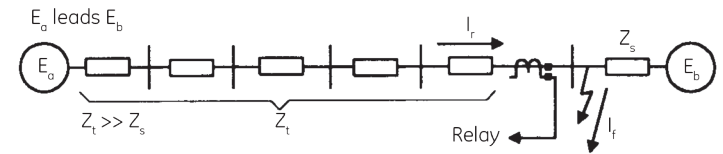

Fig 5.
Fault Behind MHO Function.

A relay that operates on the quantities given in 1, can be easily analyzed for the conditions of Figure 5 by using phasors as shown in Figure 6. The function will not operate dynamically because the angle (A) between Vop and the initial polarizing signal (voltage at relay prior to the fault) is much greater than 90 degrees. If the sensitivity of the voltage polarizing circuit is less than the arc drop, then the mho function will operate steady-state for the conditions shown because the angle (B) between the operating signal, V_{op}, and the final polarizing signal, Varc, is less than 90°. If the sensitivity of the polarizing circuit is greater than the arc drop, then steady-state operation will not occur regardless of the angle. This analysis is predicated on the memory changing from the prefault voltage to the fault voltage during some finite time period. If the fault is cleared before the memory expires, then operation will be prevented. If the memory voltage is held fixed at the prefault value, then operation for this condition will also be avoided. Note that this analysis applies for any function, self-polarized or cross-polarized for any three-phase fault, because the only voltage left to create the polarizing quantity is the arc voltage itself. For phase-to-phase, or phase-to-ground faults (assuming arc resistance only in the fault), a cross-polarized function will perform properly because the unfaulted phase voltages will be available to create a polarizing signal that will not be shifted as much in value as is the arc voltage.
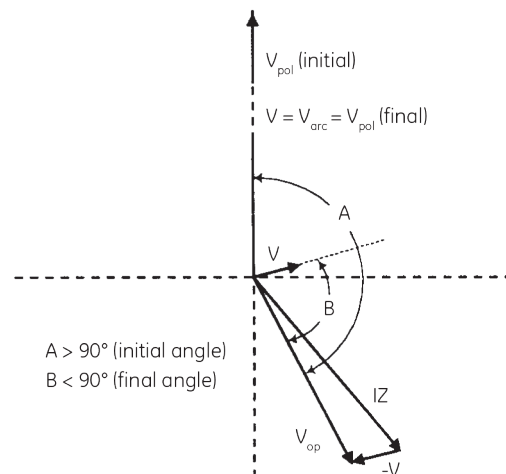

Fig 6.
Phasor Analysis of MHO.

Current Sensitivity

In addition to requiring a finite amount of voltage to operate, a mho distance function also requires a finite amount of current. The amount of current required is fixed by the design of the function and is related to the reach set on the function. For any given reach setting, the function will produce the set reach only for currents above a certain level. If the current is reduced below that level, then the function will start to pull back in reach until a current level is reached at which operation of the function will stop. For example, consider an electro-mechanical mho distance function in which torque must be produced to cause rotation of the element. The torque must be sufficient to overcome the inertia of the element plus the restraining spring that is used to hold the contacts open when no electrical restraining torque is being produced. Sensitivity of an electro-mechanical mho function could be found by examining the so-called bullet curve, an example of which is shown in Figure 7. From this curve, it can be seen that the amount of current required to operate the function is related to the basic ohmic reach of the function; i.e., the higher the basic reach that is selected, the lesser the amount of current required to produce operation. It is for this reason that the instruction books always recommend that the highest basic ohmic reach be used if the desired reach can be obtained through the use of any of the available basic ohmic reaches. For a 3 ohm basic reach setting, the function requires at least 1.5 amperes of current to produce operation. Note however, that the function will reach to only about 80 percent of the set reach at 1.5 amperes and that it takes about 5.0 amperes of current before the full reach will be obtained. The area between 1.5 amperes and approximately 5 amperes is referred to as the region of "pull back" because the full reach of the function is not obtained in this area. The lower portion of the curve shows the area of dynamic operation of the mho function.

Solid state and digital type mho functions do not require torque to operate and have no restraining springs to overcome. Howeve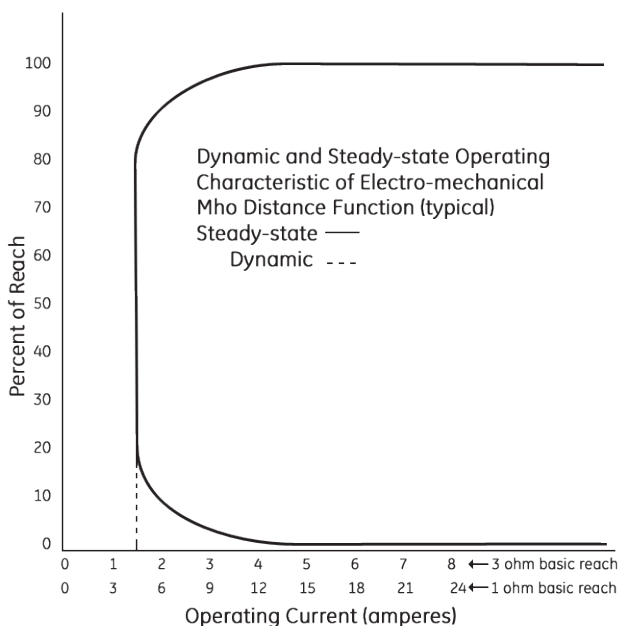r, signal levels must be established below which the functions will not be allowed to operate. This is required to overcome errors and thresholds that are indigenous to any type of electronic equipment and design (analog or digital). Sensitivity of these types of functions can be determined from curves or through equations provided by the maker of the equipment For example, the sensitivity of one type of phase distance function can be calculated as follows:

$$I_{\phi\phi} = \frac{K}{Z_r \times (1 - X)}$$

Where,

$I_{\phi\phi}$ = phase-to-phase current required to produce the actual reach

Z_r = reach setting

X = actual reach/reach setting

K = design constant

The actual reach referred to is the reach that will be obtained at the calculated current level ($I_{\phi\phi}$), taking into account any pull back. If, for example, it is desired to know the current that is required to assure that the function will reach at least 90 percent of the set reach, then X should be set equal to 0.9. Note that the current required to produce a given reach is inversely proportional to the reach setting. Longer reach settings require less current and vice versa. Functions with extremely short reaches may require a significant amount of current to produce operation and may not operate under all conditions.

Arc/Fault Resistance

For a multi-phase fault, an arc is established between the phases that results in a nearly constant voltage drop across the arc that as noted earlier is approximately equal to 4 to 5 percent of the driving system voltage. The arc appears to be purely resistive in nature and because of the constant voltage drop, the resistance varies inversely with the total current flowing in the arc. This is not strictly true for single-line-to-ground faults, wherein there may be an additional drop that is introduced through tower footing resistance, etc. If a midspan-to-ground fault occurs through a tree or fire, for example, then there could be a significant resistive component in the fault. This resistive component does not vary inversely with the current, as does the resistance in an arc, therefore, there could be a significant voltage drop across it. In any event, although the impedance of the fault is considered to be purely resistive, that does not mean that it will appear to be so to a distance function. The effect of load flow and/or non-homogeneity (system impedance angle are different) must be taken into account. This is illustrated in Figure 8.

As can be seen in Figure 8, the effect of load is to shift the resistance so that it appears to have a reactive component. The direction of the shift and the amount of shift depends on the direction and the magnitude of the load flow. System non-homogeneity has a similar effect but not nearly as severe as that caused by heavy load flow.

For a multi-phase fault, the resistance varies inversely with the current because the voltage drop across the arc is constant in magnitude. As a consequence, the system source-to-line
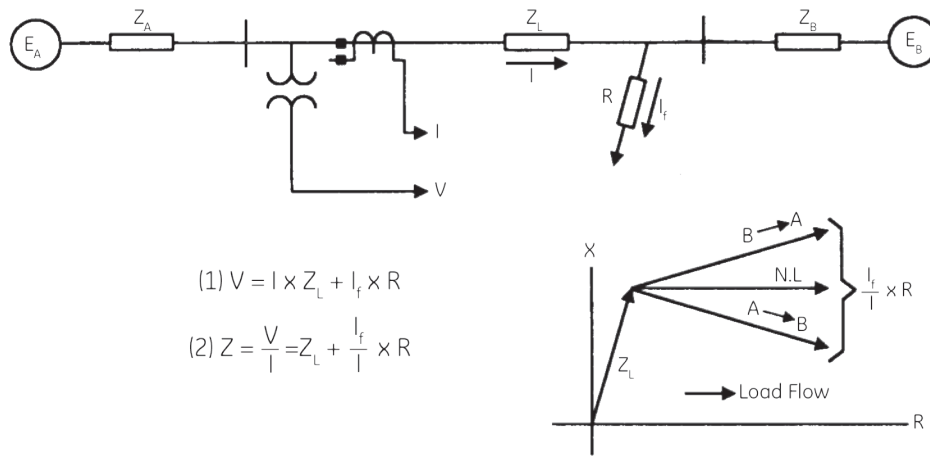

Fig 7.
Typical Bullet Curve.

$$(1)\ V = I \times Z_L + I_f \times R$$

$$(2)\ Z = \frac{V}{I} = Z_L + \frac{I_f}{I} \times R$$

Fig 8.
Effect of Load Flow Figure or Non-homogeneity on Arc/Fault Resistance.

impedance ratio becomes important in the case of multi-phase faults. As the source to line ratio increases, the voltage drop in the arc appears larger relative to the voltage drop in the line itself. The effect is to make the resistance appear to be larger relative to the line impedance as shown in Figure 9. On lines with low source-to-line ratios (typically long lines), the resistive component of the impedance seen by a distance function is very small and may be considered negligible. On the other hand, as the source-to-line ratio increases (typically short lines) the resistive component of the apparent impedance seen by the function can be quite large and can no longer be considered negligible. If the distance function is cross-polarized, then the effect of the crosspolarization will cause the characteristic to swivel in the same direction as the arc resistance itself (see Figure 3), and so preclude operation.

Fig 9.
Effect of Source-to Line (Z_s/Z_L) Ratio.

Infeed affects single-line-to-ground faults similarly, but because the resistance in the fault is linear, the effect can be much more dramatic. The effect of the infeed is to cause the voltage to be magnified in value so that the resistance can appear much larger than it actually is. In this case, the resistance may be so large as to render ground distance functions ineffective. For

example, if the relay current, I, in Figure 8 is 1 ampere and if the fault current, If, is 10 amperes, then from equation 2 of the Figure:

$$Z = Z_L + \frac{I_f}{I} \times R = Z_L + 10R$$

As far as any distance function at the left is concerned, the fault resistance (for a ground fault with linear resistance) appears to be 10 times as large as it actually is thus increasing the chance that the function may not operate. If the fault is cleared at the right terminal, then the distance function at the left will see the true resistance at that time ($I_f = I$) and the function may operate (but not necessarily). At the right terminal of the line the effect will not be as large, and depending on the magnitude of the resistance, a ground distance function located there may or may not operate. If the ground distance function at the right does not operate because the resistance is too large, then the fault cannot be cleared by distance relays, and ground directional overcurrent relays (or a scheme employing current alone) will have to be employed to insure clearing for high resistance ground faults.
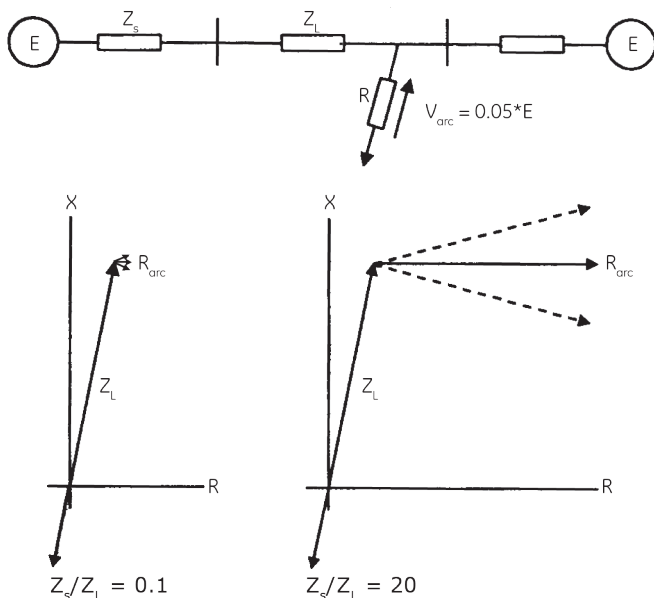
Replica Impedance

Many solid state relay systems (and some electro-mechanical relays) use a magnetic circuit such as a transactor to develop the transmission line replica impedance. A transactor is an iron core reactor with an air gap, and it produces an output voltage that is proportional to the input current. The transfer impedance of the transactor is used to define the reach, Z, and the angle of maximum reach, ⌷ of the mho distance function shown in Figure 1. The transactor removes the DC component from the current signal. Digital relays may use a socalled "software implementation" of a transactor, rather than a physical transactor, to create the replica impedance. In this way, the dc component can be removed from the current derived signal that is used in a digital relay.

In setting mho distance functions, it is desirable to match the replica impedance angle to the line impedance angle as closely as possible. In this way, the function will replicate the line voltage which will lead to an accurate measurement being made. If the replica impedance is set at an angle other than the line angle, then replication of the line voltage will be obtained
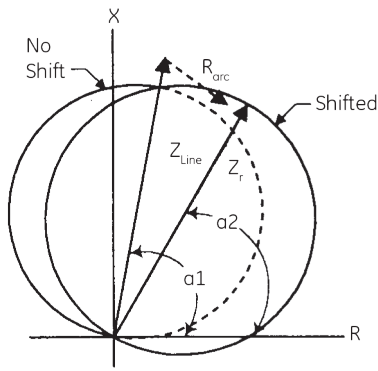
Fig 10.
Phase Shifted Function.

only if there is no dc offset in the current. Any dc offset in the fault current will produce an error in the replicated voltage until the dc offset subsides. The error will be in the direction to promote overreaching if the angle is made lower than the line angle. Of more concern when an angle other than the line angle is used is demonstrated in Figure 10. In this application, the zone 1 function which is typically set to reach 90 percent of the line impedance, has been tipped away from the line in an attempt to obtain greater coverage for arc resistance while still maintaining a reach of 90 percent along the line angle. Greater arc resistance coverage has been obtained, but at the cost of possible overreaching for a fault at the end of the line with fault/arc resistance as shown in the Figure. While not shown, the dynamic response and the variable response of a crosspolarized mho function will exacerbate the problem because the characteristic will be expanded beyond that shown in the Figure.

Zero Sequence Current Compensation

It was shown earlier for a fault at the balance point that the voltage developed in the relay would be equal to the voltage drop across along the line for multi-phase faults. This will not be true for a ground distance function during a ground fault if that function uses only the faulted phase voltage V, the faulted phase current 1, and a reach setting that is based only on the
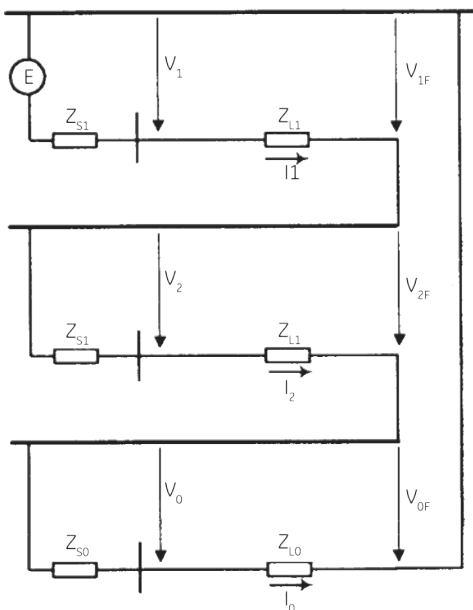

Fig 11.
Sequence Network Connections for SLG-Fault.

positive sequence impedance (Z_{L1}) of the line. For a phase A to ground fault at the location shown on the system of Figure 1, the sequence networks are connected as shown in Figure 11. The voltage at the relay (V_a) can be calculated as follows:

$$V_a = V_1 + V_2 + V_0$$

Where,

$$V_1 = I_1 \times Z_{L1} + V_{1F}$$

$$V_2 = I_2 \times Z_{L1} + V_{2F}$$

$$V_0 = I_0 \times Z_{L0} + V_{0F}$$

Therefore,

$$V_a = I_1 \times Z_{L1} + I_2 \times Z_{L1} + I_0 \times Z_{L0} + (V_{1F} + V_{2F} + V_{0F})$$

But,

$$(V_{1F} + V_{2F} + V_{0F}) = 0$$

Therefore,

$$V_a = (I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L0}$$

The voltage at the relay, V_a, is not simply made up of the drop in the positive sequence impedance of the line as for a three-phase fault, but it also includes a factor that is proportional to the zero sequence impedance of the line and the zero sequence current seen by the relay. If a ground distance relay just uses the current I_a and is set with a replica impedance (Z_R) that is equal to the positive sequence impedance (Z_{L1}) of the line, then the IZ quantity would be as follows:

$$I_a = I_1 + I_2 + I_0$$

$$IZ = I_a \times Z_R = (I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L1}$$

Note that the IZ quantity is not equal to V_a because of the difference between the positive sequence impedance and the zero sequence impedance of the line. The IZ quantity can be made equal to V_a by multiplying the zero sequence current by the ratio of the zero sequence impedance to the positive sequence impedance (Z_{L0}/Z_{L1}) of the line. If this ratio is called K_0, then a compensated current (I_{ac}) results:

$$I_{ac} = I_1 + I_2 + K_0 \times I_0$$

The IZ quantity then becomes:

$$IZ = I_{ac} \times Z_{L1} = (I_1 + I_2) \times Z_{LI} + K_0 \times I_0 \times Z_{L1}$$

$$IZ = (I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L0}$$

From this, the operating quantity, Vop, can be calculated:

$$V_{op} = IZ - V_a = \{(I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L0}\} - V_a = \{(I_1 + I_2) + I_0 \times Z_{L0}\} - (I_1 + I_2)$$

$$+ I_0 \times Z_{L0} = 0$$

IZ is now exactly equal to V_a and the operating quantity IZ-V is therefore equal to zero just as was the case for the three-phase fault described earlier. K_0 is referred to as the zero sequence current compensation factor and it is used to match the zero sequence impedance of the line. The ratio of the voltage V_a to the compensated current I_{ac}, now yields:

$$\frac{Va}{Iac} = \frac{(I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L0}}{I_1 + I_2 + K_0 \times I_0} = \frac{Z_{L1}\{I_1 + I_2 + (Z_{L0}/Z_{L1}) \times I_0\}}{\{I_1 + I_2 + (Z_{L0}/Z_{LI}) \times I_0\}} = Z_{L1}$$

The effect of using K_0 therefore, is to allow the function to measure impedance in terms of the positive sequence of the line, which in turn allows the user to set the function in terms of the positive sequence impedance of the line.

Depending on the relay, the K_0 factor may also be expressed as follows:

$$K_0 = \frac{Z_{0L} - Z_{1L}}{K \times Z_{0L}}$$

Where, K can be 1 or 3 as determined by the relay design.

Regardless of how K_0 is defined, the effect on performance is the same as described above.

Operation of Ground Distance Functions for Reverse Double-Line-to-Ground Faults

As was just shown, zero sequence current compensation facilitates application of ground distance functions, but it, along with the relay reach, may also lead to an operational problem with the ground distance function associated with the unfaulted phase during a doubleline- to-ground fault behind the function (the Phase A function for a BCG to ground fault, for example). Consider the system shown in Figure 12.
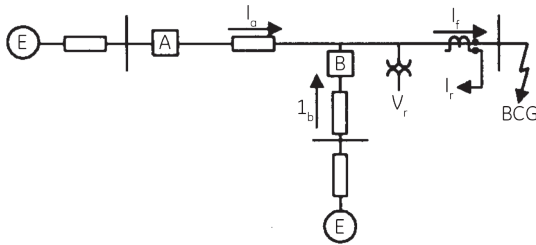

Fig 12.
BCG Fault Behind Function.

If breaker B is open, then the zero sequence current seen by the phase A ground distance function will be fed from a single source and it will be equal to the positive and negative sequence currents flowing down the line. On the other hand, with breaker B closed, the zero sequence current seen by the function can be quite large, especially if the zero sequence source behind breaker B is very strong. The effect of the strength of the zero sequence current and the relay reach can be seen by examining the operating quantity, Vop as shown in Figure 13, for the phase A distance function set with a reach of Z_R.

The phase relationship of the sequence currents as seen by the relay are shown in Figure 13a (all impedance angles were assumed to be 90° for simplicity). Note that the relay currents are 180° out of phase with those seen by the power system because the fault is behind the relay and the current transformers, when connected properly, will cause this apparent shift. The corresponding V_{op} operating phasors are shown in figures 13b and 13c for small I0 and small Z_R and large I0 and large Z_R, respectively. The polarizing quantity for this function could be the V_a voltage itself or it would be a cross-polarized voltage which would be in phase with the V_a voltage. The conditions shown in Figure 13a therefore represent a non-operating condition because V_{op} and the polarizing voltage are 180° out of phase. As the zero sequence current and/or reach is increased the point will be reached where the V_{op} signal will reverse as shown in Figure 13c. This now represents an

operating condition because V_{op} and the polarizing signal are now in phase.

In general, operation for this condition is minimal on two-terminal line applications unless extremely long reaches are used. The possibility is increased significantly on three-terminal line applications because of the infeed from the third terminal and also because long reaches are often used because of the effect of infeed. Ground distance functions have been designed and are available to preclude operation for this condition. Each application should be checked for the possibility of operating for this condition.
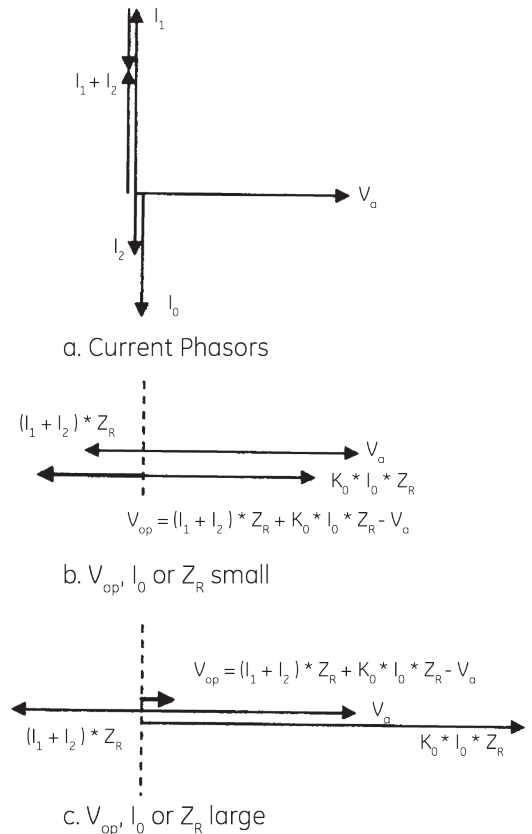

a. Current Phasors

b. V_{op}, I_0 or Z_R small

c. V_{op}, I_0 or Z_R large

Fig 13.
Sequence Current and V_{OP} Phasor Diagrams for Reverse BCG Fault.

Zone 1 Ground Overreach for Remote Double-Line-to-Ground Fault

It was just shown that the ground function associated with the faulted phase could operate for an L-L-G fault directly behind the function. Another problem can occur for the same fault for a zone 1 ground distance function located at the other end of the line (terminal A). In this case it is possible for the zone 1 function associated with the leading phase [5] to overreach for a resistive fault with heavy load flowing away from the relay location (refer to reference 5 for details). Operation can be prevented for this condition through design of the function or by limiting the reach of the function. Refer to the instruction book for a specific function to see if it is designed to preclude operation without reach limitations under these conditions or if the reach must be limited to preclude operation.
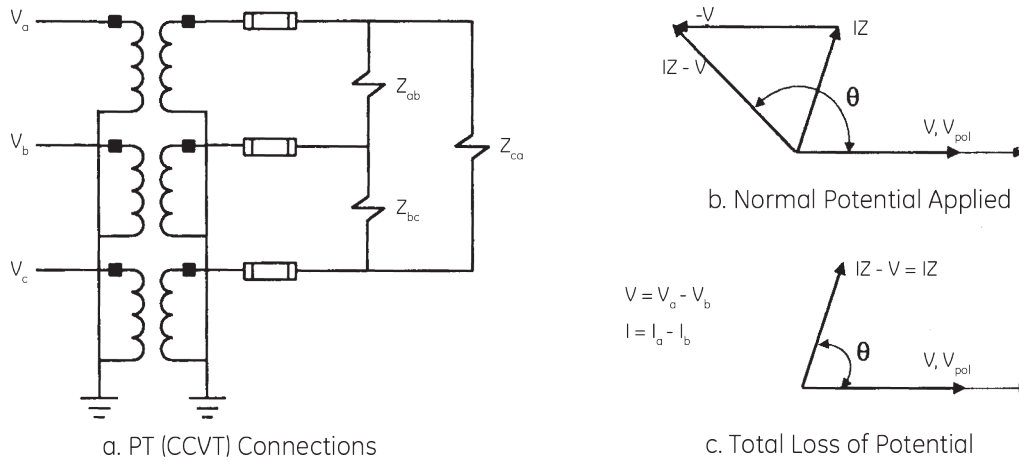
a. PT (CCVT) Connections

b. Normal Potential Applied

$$V = V_a - V_b$$
$$I = I_a - I_b$$

c. Total Loss of Potential

Fig 14.
Potential Connection and Phasor Diagrams for Total Loss of Potential.

Loss of Potential

Distance functions may operate during when potential is lost, but the following factors must be considered to determine what the overall effect will be:

1. The design of the function and the settings placed on it (reach, angle, etc.)

2. The magnitude and direction of load flow

3. The nature of the potential loss (full or partial)

4. The potential transformer (CVT or CCVT) connections and the total connected burden.

To determine the effects of the above factors, each type of distance function must be examined separately. A phasor analysis will be provided for a self-polarized and a positive sequence polarized phase mho distance function that uses the operating principles shown in Figure 1. For this function, operation will occur when the operating quantity ($V_{op} = IZ-V$) and the polarizing quantity (V_{pol}) are within 90° of each other.

The phase AB function will be analyzed and unity power factor will be assumed (lagging power factor will exacerbate the problem whereas leading power factor will be less onerous). The potential connections to the function and the phasor diagrams

for a total loss of potential are shown in Figure 14. For this case, the angle □ is greater than 90° with normal potential applied, but is less than 90° after the loss of potential when V_{op} is equal to IZ and the polarizing voltage is the memorized voltage V. The function will therefore produce an output, and the output will last as long as the memory lasts. Unfortunately, this is generally long enough to cause a trip, especially in the case of a zone 1 function, or an overreaching function in a blocking or hybrid type of relaying scheme. Although a self-polarized function was analyzed for this example, an output will occur for the case of a total loss of potential for any phase distance function regardless of the type of polarization that is used.

The analysis for a partial loss of potential (phase A fuse blows) is shown in Figure 15. In this case, the self-polarized function will not operate dynamically, but it will operate steady-state as shown

Because the angle □ between V_{op} (IZ - V_{ab}') and V_{pol} (V_{ab}') is less than 90°. The positive sequence polarized function will not operate dynamically nor will it operate steady-state (angle □1 is greater than 90°) because the polarizing voltage Vab1 does not shift in phase although it is reduced in magnitude. Thus the positive sequence polarized function is much more secure than is the self-polarized function.

a. Normal Potential

$V_{ca'} = V_{ab'}$ = potential that funtion sees after loss of potential (LOP)

b. Loss of Phase A Potential

V_{ab1} = positive sequence voltage seen by ab funtion after loss of potential

C. Vop and Vpol Phasors after LOP
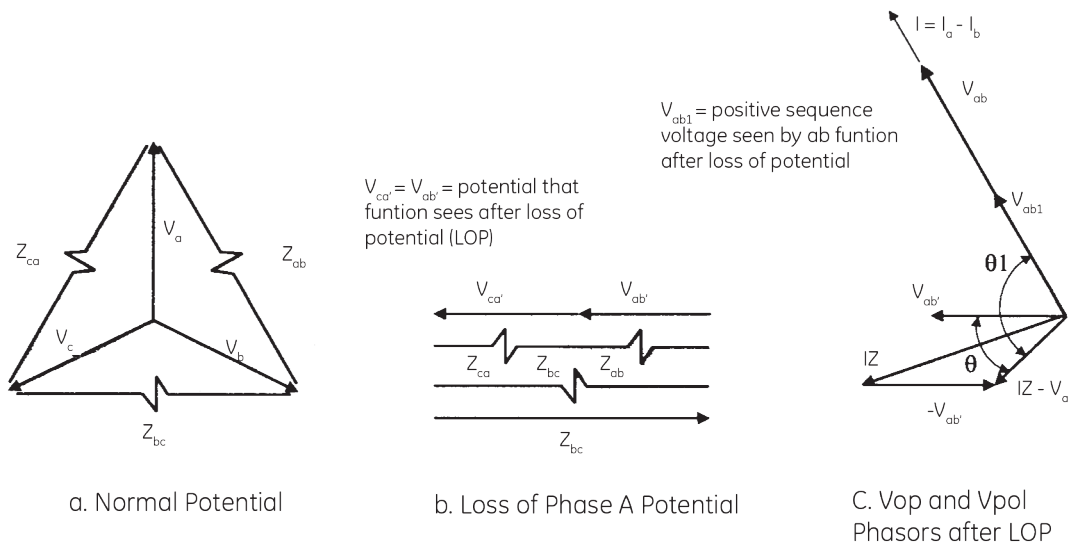
Fig 15.
Potential Connection and Phasor Diagram for Partial Loss of Potential.

Distance Relay Fundamentals

A similar type of analysis to that used above can be used to analyze the performance of any type of distance function as the result of a loss of potential.
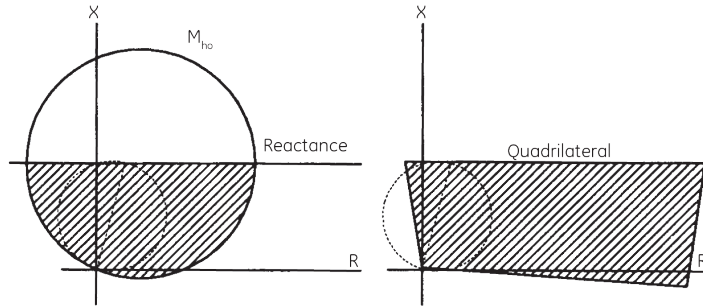
3. Reactance Functions

Fig 16.
Reactance Type Functions.

A simple reactance function is shown in Figure 16. Also shown in this Figure is a so-called quadrilateral function which is in reality a reactance function. In each case, some form of supervision is required because a reactance function is inherently non-directional. Reactance type functions are often selected because of the apparent increase in resistance coverage over the traditional zone 1 function (shown dashed in the Figure). It should be remembered, however, that a crosspolarized mho function will offer resistance coverage greater than that shown because of its variable nature. Reactance type functions are susceptible to overreaching for faults with resistance in them unless the function is designed to preclude this type of operation. In addition, some quadrilateral functions may not operate for a resistive fault right at the relay location. To demonstrate the overreach problem and one way to overcome it, refer to Figure 17a and 17b.
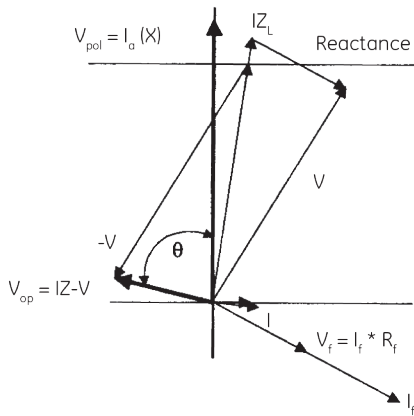
Fig 17a.
Self-Polarized Reactance Function (I_a).

Figure 17a shows a self-polarized phase A ground reactance function using the phase A current to derive the polarizing quantity. As can be seen, the effect of arc resistance and load flow (away from the relay in this example) has caused the function to overreach ($\theta < 90°$). For load flow in the other direction, this self-polarized function will have a tendency to underreach. The negative sequence polarized function shown in Figure 17b does not overreach for the same condition as does the selfpolarized function, nor will it underreach for load flow in the other direction. Other polarizing sources, $3I_0$ for

example, may be used for polarizing to prevent overreaching. Further details on the performance or reactance type functions can be found in reference 1.
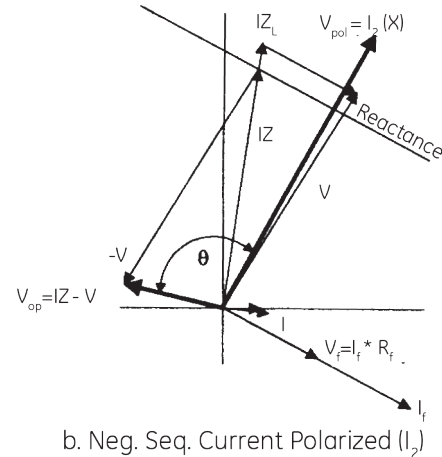
b. Neg. Seq. Current Polarized (I_2)

Fig 17b.
Negative Sequence Current Polarized Reactance Function (I_2).

4. Coupling Capacitor Voltage Transformer (CCVT) Transients

Coupling capacitor voltage transformers are an economical way to obtain the potential required to operate distance (and directional) type relays. They also provide a means to couple communication channels to the power line for use with various relaying schemes. Unfortunately, a CCVT may not reproduce the primary voltage exactly and can introduce significant error into the distance relay measurement The transient error that is produced by the CCVT becomes more pronounced as the change in the voltage from prefault to fault is increased (a fault at the end of a line with a high source to line impedance (ZS/ZL) impedance ratio, for example). A typical CCVT transient is shown in Figure 18.

Fig 18.
Typical CVT Transient.

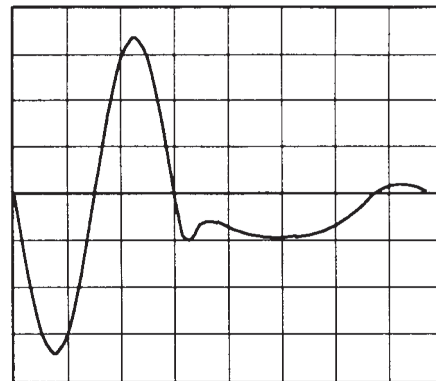If a transient like this were to occur for a fault at the end of a line with a high Z_s/Z_L ratio, it could cause a zone 1 distance function to overreach. To see how this could occur, refer to Figure 19.

The operation is shown for the distance function and system of Figure 1 with the assumption that the source to line impedance ratio (Z_s/Z) is approximately 15. The ideal response shows that
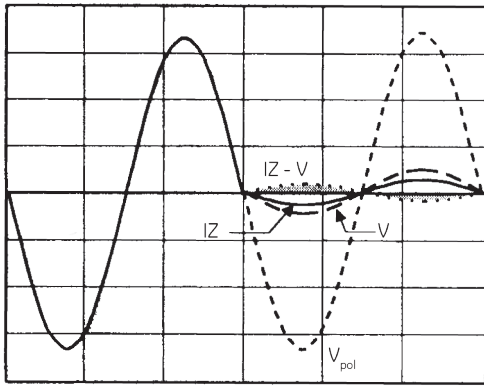
a. Ideal Response
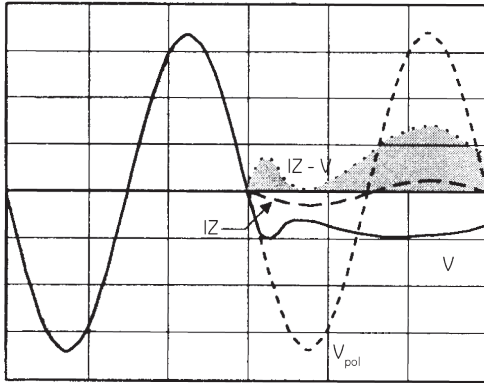
b. Transient Response

Fig 19.
Distance Function Operation for Ideal and Transient CVT Response.

the function will not operate because the operating quantity, IZ-V, and the polarizing quantity, V_{pol}, are 180° out of phase. The transient response on the other hand shows that the function will operate during the second half cycle because the operating quantity and the polarizing quantity are in phase with each other (see shaded area). This example shows that care should be taken in the application of zone 1 distance functions and that the recommendation of the manufacturer should be followed in making the reach settings on the functions.

CCVT transients may also cause loss of directionality for zero voltage bus faults behind the relay. The use of memory voltage and cross-polarization will reduce this tendency.

5. Conclusion

Distance functions perform a very important and essential part of many power system protective relaying systems. This paper discussed possible problem areas that can be encountered in the design and application of distance type function. It is the responsibility of the manufacturer to design relays, and to aid in their application, with these problems in mind. However, it is the ultimate responsibility of the user to insure that the relays are applied correctly.

6. References:

[1]   Polarization of Ground Distance Relays, W.Z. Tyska

[2]   Dynamic characteristics of Mho Distance Relays, GE Publication GER-3742

[3]   Art & Science of Protective Relaying, C. Russell Mason, John Wiley & Sons, Inc.

[4]   Protective Relaying, J. Lewis Blackburn, Marcel Dekker, Inc.

[5]   Effects of Load Flow on Relay Performance, General Electric Publication GER-3743

[6]   Ground Distance Relaying: Problems and Principles, General Electric Publication GER-3793

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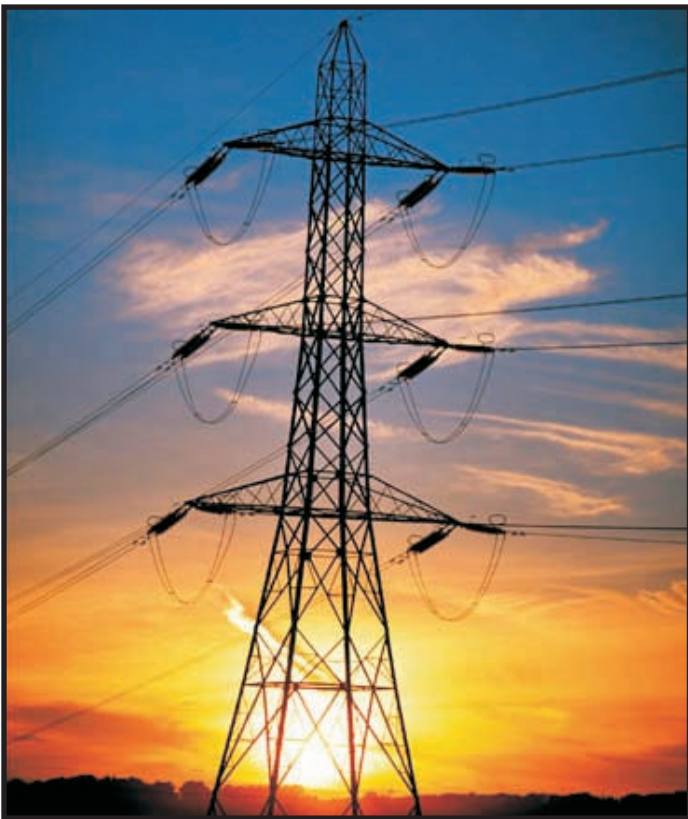
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A World of Standards

Gustavo Brunello
GE Multilin

1. Abstract

This regular column will report activities in the IEEE, IEC and other standard development organizations/ technical bodies such as NERC, UL, CIGRE regarding protective relays and power systems communications. The focus will be on new standards, brief analysis of them and other related news that affect relays or their application.

2. Brief History of Standards

An old saying goes: "Standards are good, everybody should have one!". Funny indeed. However, not so when one analyzes the consequences of having the world divided in mainly 2 distinct power system frequencies (50Hz and 60 Hz) or the many different electric plugs that exist around the globe. There are many other more dramatic stories whose origins can be traced to the lack of standards.

Standards have existed since the beginning of recorded history. Relics from ancient civilizations such as Babylon and early Egypt provide ample evidence that standards were being used as far back as seven thousand years ago.

However, it was not until the latter years of the 19th Century that the value of standardization in specifications, materials, testing and conformance was recognized as a national priority. In response countries have created their own standardization bodies, such as:

1884   AIEE (USA) predecessor of the IEEE

1901   BSI (United Kingdom)

1906   IEC (presently based in Switzerland)

1907   UTE/ USE (France)

1909   CEI (Italy)

1917   DIN (Germany)

1918   ANSI (America)

There are other institutions that do not specifically develop standards although they have a long tradition influencing the way one uses and applies protective relays:

1921   CIGRE (headquartered in France)

1968   NERC (North America Reliability Council)

3. Benefits of Using Standards

Standards are such an integral component of our economic, social and legal systems that they are often taken for granted and their crucial role in a modern society is often not recognized.

Standards are the tools we use to organize our technical world and the measures we employ to establish norms for management procedures. They underpin consumer expectations that products purchased will be safe, reliable and fit-for-purpose.

Globally there are well over half a million published Standards. These are the products of over 1,000 recognized Standards development organizations worldwide. These figures don't take into account the innumerable internal Standards, which underpin any successful business. This massive collection of accumulated knowledge and expertise does not come cheaply; it is an expensive exercise to develop a publicly available Standard. They are copyright material and cannot be freely copied or distributed.

Technical Standards represent a consensus decision from a committee of technical experts specifically chosen to bring a broad range of viewpoints to the committee deliberations and approved by an accredited standards development organization; i.e. IEEE or IEC.

The globalization of commerce, with its demand for fast mechanisms of trade, and the de-regulation of the electrical market that has taken place in the last 15 years have brought changes in the way countries approach the standardization of electrical equipment, making International Standards more relevant than National ones.

Specifically, in the field of protective relays and communications equipment in the substation, we have witnessed a process of gradual strengthening of internationally recognized standards such those from the IEC and IEEE. A clear example is CENELEC, the European Committee for Electrotechnical Standards whose mandate is to harmonize electrical Standards within 29 European countries and with those of the IEC.

4. Type of Standard Documents

Contrary to Codes (Electric Safety Code or Fire Code), which are of compulsory observance, Standards are binding only when the parties who entered into a contract agree to follow them. It is important to note the different types of standards produced by the different standard development organizations.

The IEEE publishes the following type of standards:

- **Standards:** documents with mandatory requirements. They are generally characterized by use of the verb "shall".

- **Application Guides:** documents in which alternative approaches to good practice are suggested but no clear-cut recommendations are made. They are generally characterized by use of the verb "should".

- **Recommended practices:** documents in which procedures and positions preferred by the IEEE are presented.

- **Trial-Use documents:** publications that are effective for not more than two years. They can be any of the categories of standards publications listed above but it is used mainly when introducing standards of newest technology.

The IEC, www.iec.ch, similarly to the IEEE, publishes the following type of documents:

   a. International Standards

   b. Technical Specifications

   c. Technical Reports

5. Relay and Communications Standards

Our interests lay on electrical Standards, specifically those for protective relays and, more recently, those for data communications management, equipment and protocols applied to electric power systems. Standardization bodies, recognizing the different expertise required for protection and communications, have separate Technical Committees responsible for each of them.

At the IEEE:

- **Power System Relaying Committee** (PSRC)

   It's scope includes protective, regulating, monitoring, reclosing, synch-check, synchronizing and auxiliary relays employed in transmission, generation, distribution and utilization of electrical energy. Its website http://www.pes-psrc.org/ is a valuable source of information where relay engineers can download technical reports, recommended practices and some application guides. GE Multilin engineers and experts actively participate in the preparation of these documents.

Others IEEE Committees that produce standards related to protective relays and power systems communications are:

- **Power System Communications Committee** (PSCC)

   http://www.ewh.ieee.org/soc/pes/pscc/index.html. It develops communication standards, covering the treatment of: Power Line Carriers, Radio and Other Free Space Communications, Fiber Optic Communications, Wire Line Communications and Communications Protocols used in Utilities among others.

- **Substations Committee**

   http://www.ap-concepts.com/ieee_substations.htm. Its scope includes: Automatic and Supervisory Control Systems (SCADA standards such as the C37.1) and treatment of Data Acquired Within Substations among others.

Within the IEC there are also 3 Technical Committees (TC) that deal with standards related to protective relays and power systems communications. They are: TC57, TC94 and TC95. Please note the new TC94 that was created after splitting the original TC95.

- **TC57 - Power systems management and associated information exchange**

   Includes standards for power systems control equipment and systems including EMS (Energy Management Systems), SCADA, distribution automation, teleprotection, and associated information exchange for real-time and non-real-time information. The presently popular IEC 61850 Std is responsibility of the TC57 Committee and not of the Relay Technical Committee.

- **TC94: All-or-nothing electrical relays**

   Includes standards applicable to all-or-nothing electrical relays used in the various fields of Electrical Engineering, normally produced in very large numbers as components of electromechanical or electronic equipment.

- **TC95: Measuring relays and protection equipment**

   Includes standards for measuring relays and protection equipment used in the various fields of electrical engineering, taking into account combinations of devices to form schemes for power system protection including the control, monitoring and process interface equipment used with those systems.

Protective Relay Standards published by the IEEE and the IEC are similar but not equivalents and we will analyze their basics differences in future issues of this Journal. It is interesting to note that the IEEE has only a few Standards related to protective relays but many Application Guides, Recommended Practices and technical reports. Contrary, the IEC has a significant number of Standards for Protective Relays but very few, if any, Technical Specifications or Technical Reports.

6. Conclusions

In 2002 a new cooperation agreement between the IEC and the IEEE seeks to enhance the creation of global technical Standards. The agreement involves a dual-logo arrangement in which the logos of both organizations will appear on Standards accepted and approved by the IEEE and the IEC. Looking forward, if people keep their commitment to the standardization effort, we will finally be able to add 1 word to the old saying: "Standards are good, everybody should have the same one".

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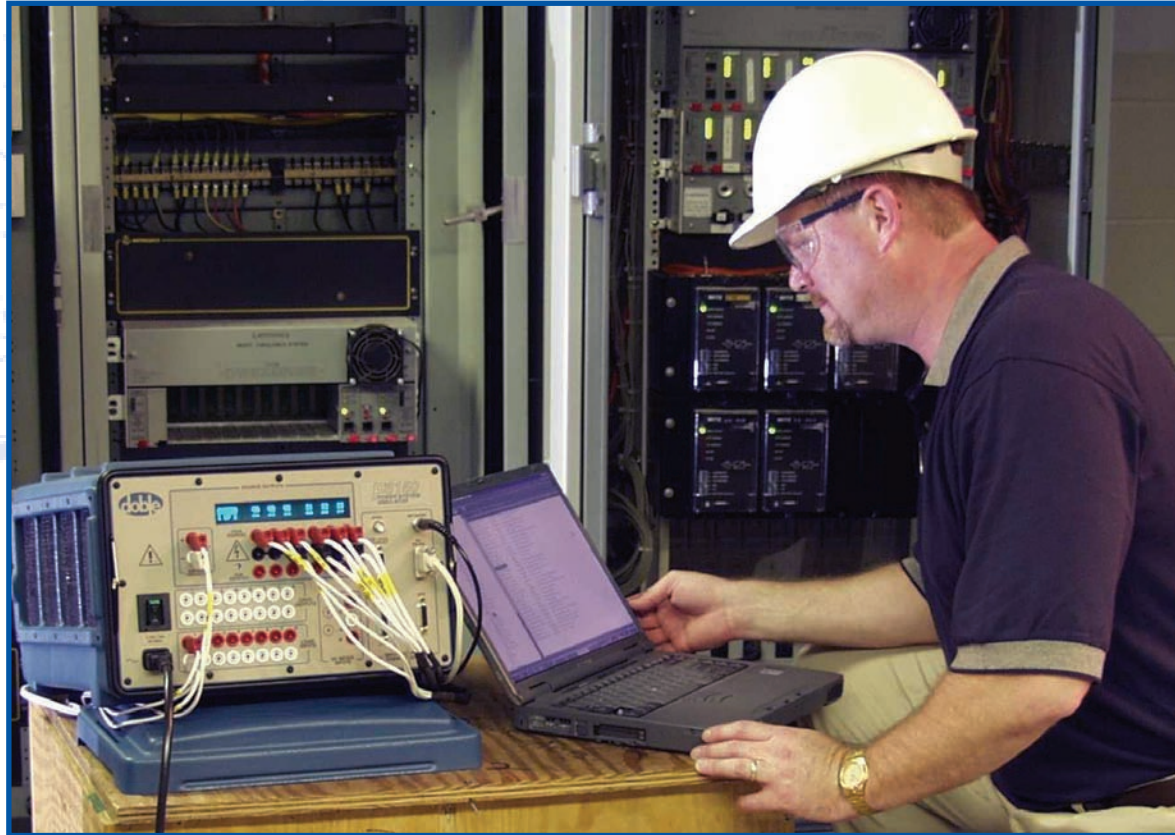
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[1] California

[2] Vancouver

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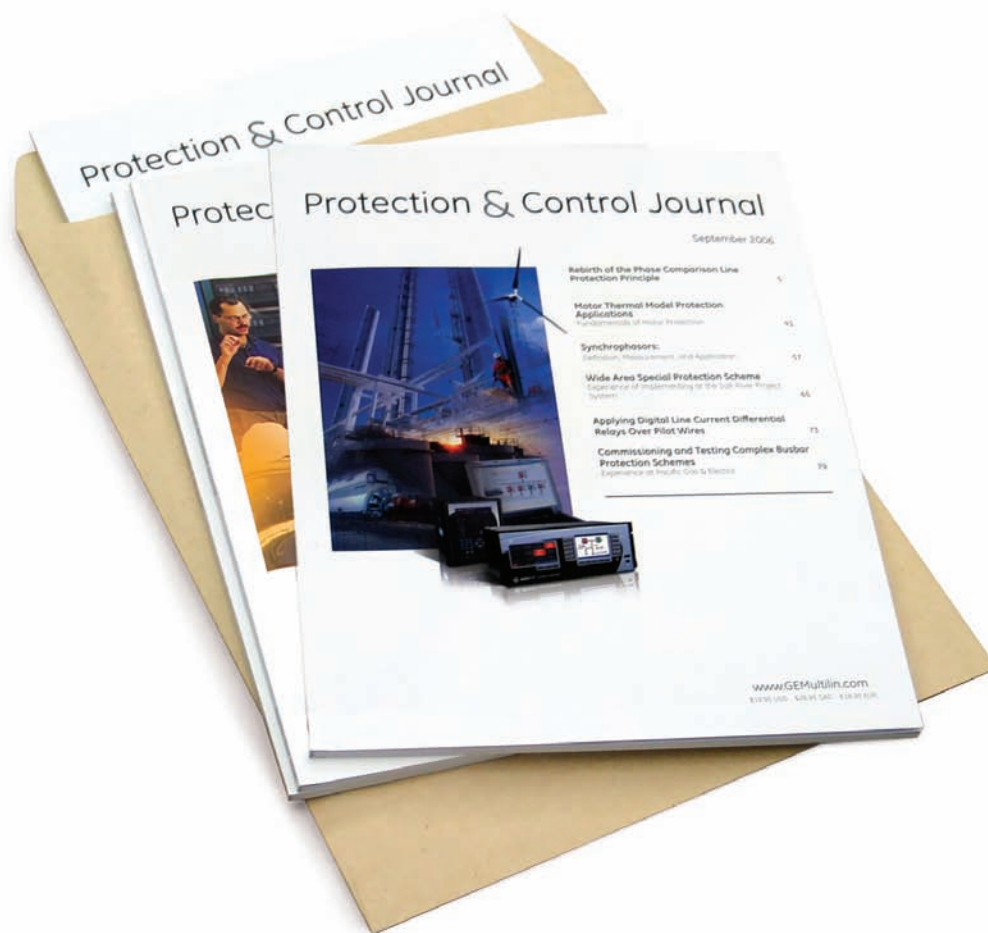
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