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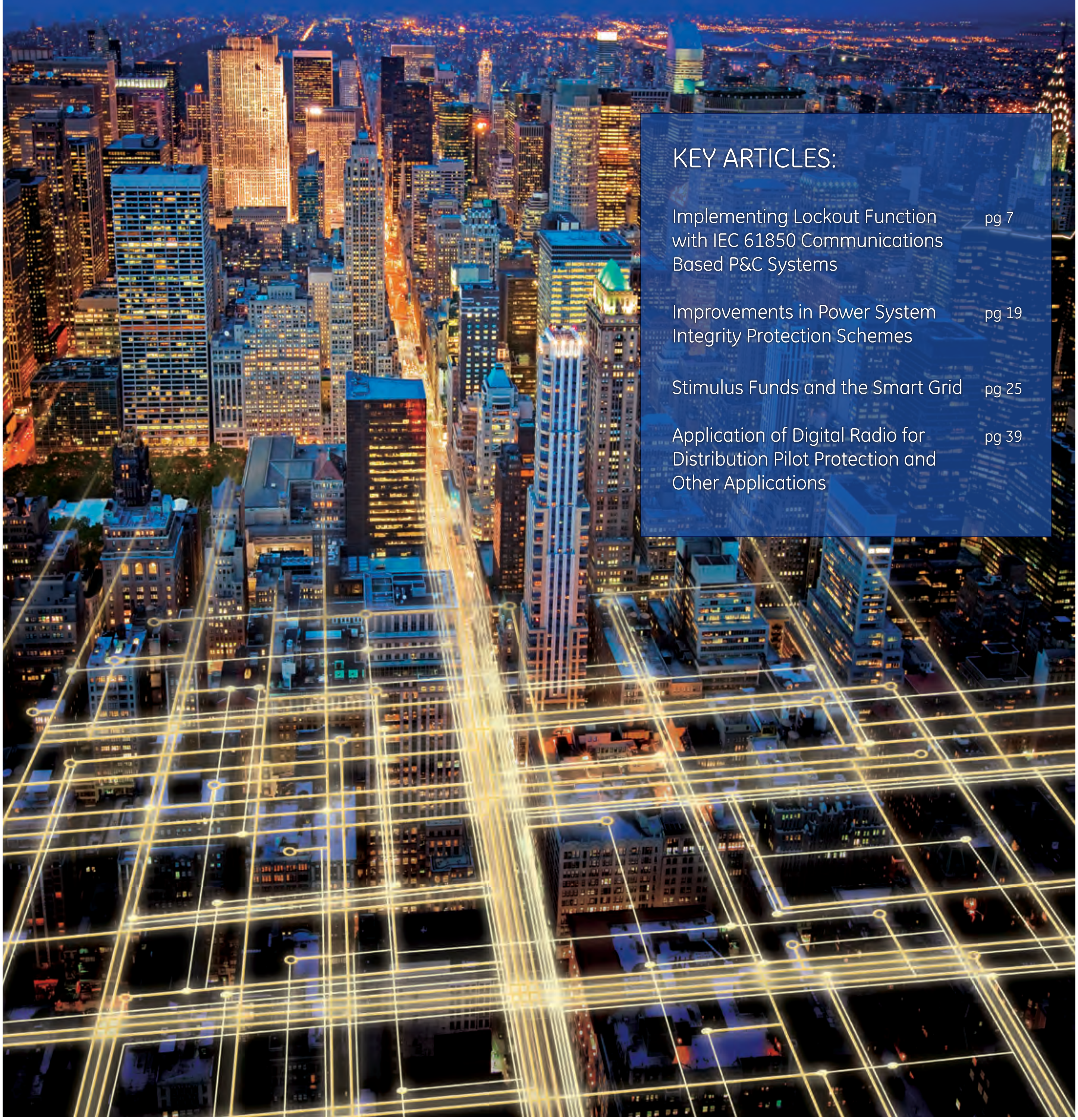

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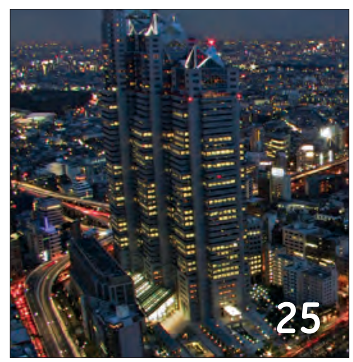
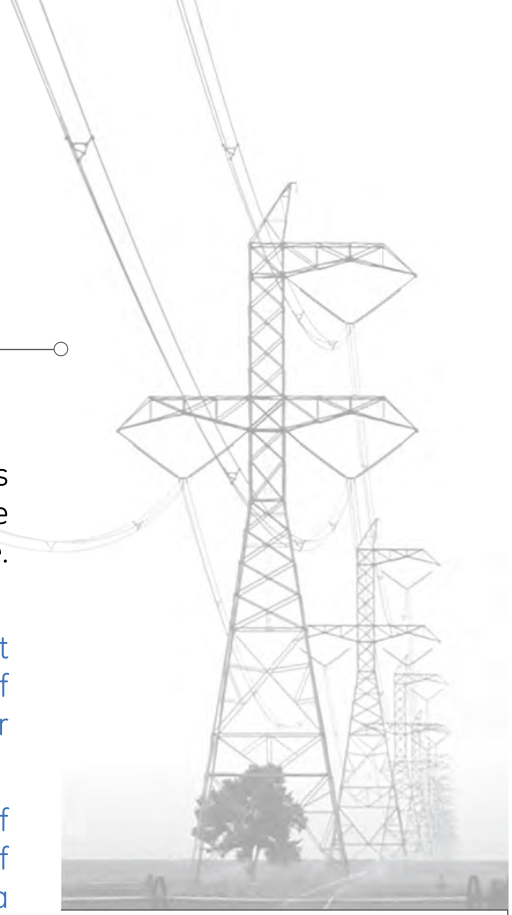


ELIOT F. ASSIMAKOPOULOS
Market Development Manager - Smart Grid



Realizing the true value of Smart Grid

The analog to digital conversion of the telecommunications infrastructure at the turn of this century significantly impacted the global socioeconomic landscape in a relatively short period of time. It enabled the advent of the Internet and the digital economy.

The new social economy spans all aspects of life in a manner that is yet to be fully appreciated. The analog to digital conversion of our transmission and distribution infrastructure towards a smarter grid holds a similar promise.

The real value of smart grid goes beyond the digitization of our energy infrastructure with its commensurate benefits. If implemented correctly, the smart grid can bring about a new era in energy.

For the first time in history, we now have the ability to significantly affect the demand-side economic equation for energy. Up until now, we have only been able to "tweak" the supply-side to include alternative energy sources such as solar and wind. With smart grid we can finally begin to work the demand-side to optimize customer interaction with energy supply. The smart grid will allow consumers to utilize their load resources in a manner that is economically beneficial to them, their utilities, and enterprising businesses. Even better, the smart grid will eventually offer a viable alternative to the importation of fossil fuels by enabling both the wide-scale integration of plug-in hybrid vehicles into the grid and the optimal integration of renewables on the transmission and especially the distribution grid. All of which are viewed as key elements in achieving a new era in energy's relatively young history.

However, it will take time to digitize our electrical infrastructure, much longer than the transformation of the telecommunications/internet industry as the T&D industry is one of the largest asset holding institutions in the world. Moreover, the infrastructure investment has to address multiple elements within the T&D grid such as metering, communications, substation automation, backoffice systems, renewables integration, and systems visualization. In other words, a successful technology investment in smart grid will require a systematic approach that blends a span of technologies and applications that are holistic in nature and are designed with a long-term view in mind.

This issue of the Protection and Control Journal features several articles that seek to identify some of the key technology solutions that are part of realizing a smart grid. On the distribution level, we explore substation automation and solutions that increase the reliability of distribution system networks via fault isolation, sectionalisation and power restoration schemes. We will analyze wide area monitoring and protection system technology and how they can increase the reliability of the transmission system through real-time observability and dynamic response to changes system conditions. In a feature article, "Communications for the Smart Grid", we explore how use of open and standards based system design is key to the supporting of advanced system integrations.

In order to realize the vision of smart grid, technology solution sets like some of those mentioned in this issue are critical cornerstones for achieving the benefits that smart grid promises. They create the foundation for a healthier energy supply and demand mix, improved reliability, increased asset optimization, and the corresponding economic benefits that will accompany these capabilities. As noted, however, the transformation of the grid's legacy infrastructure is a significant effort that will take some time to effect, while accruing incremental benefits along the way. Consequently, smart grid should be viewed as more of a journey than a destination; a journey towards achieving a sustainable energy future.

Eliot Assimakopoulos is Market Development Manager for Smart Grid at General Electric's Digital Energy Business.

Mr. Assimakopoulos has more than 15 years of experience in the construction, energy, and high technology industries. For the past several years, he has led efforts within GE to advance technology development for smart grid & renewable energy and establishing partnerships with State, Federal, and commercial organizations to achieve sustainability objectives.

Implementing Lockout Function with IEC 61850 Communications Based P&C Systems

Dave McGinn
GE Digital Energy

Paul Myrda
Electric Power Research Institute

Bogdan Kasztenny, Dale Finney

1. Introduction

Many utilities employ lockout relays (ANSI device number 86, electrically operated, hand or electrically reset) that function to shut down and hold equipment out of service on the occurrence of abnormal conditions. These utilities have long standing operating procedures and practices that presume the presence of lockout relays. There is usually great reluctance to abandon these procedures and practices to accommodate the implementation of a new protection and control technology such as IEC 61850, as typically the utility's planning horizon envisions converting only a small part of the utility's system.

This paper surveys the history and traditional practices related to lockout relays, and lays out the essential features that should be considered in the implementation of lockout in next generation communications based protection and control systems. One of such systems, based on remote I/O units deployed throughput the switchyard (process bus), is described in great detail.

In addition to the key functions of lockout that need to be retained, new issues occur when implementing lockout functions in communication-based protection and control systems. With multi-function relays tripping and closing breakers both by direct connection and over a local communications network, there are drivers to implement the lockout function in a distributed fashion. Multiple virtual components replace a single hardware component. Two redundant systems are configured to trip the same breaker – should they each incorporate a lockout function? A concern is the behavior of the P&C system both following and during outages to individual relays in the system and/or portions of the communications network. Such outages may result from power supply interruptions, component failures, and maintenance activities. Conversely, the lockout functions should not unduly restrict testing and repair activities that can be accomplished without or with limited power equipment outages.

This paper reviews the essence of lockout functions, introduces and addresses new issues when implementing the lockout in the IEC 61850 communication-based environment, and presents a specific example of application of the lockout in the IEC 61850 world.

2. Traditional Lockout

Lockout relays are used by many utilities in electrical power transmission substations to trip and hold out of service a protection zone on the occurrence of a relay operation that requires inspection and/or repair before the zone may be safely placed back in service. A protection zone could be a transformer, a bus, a transmission line or feeder, a static capacitor, or other power system element.

A transformer zone lockout relay for instance is tripped by its current differential or gas protection, operations that strongly indicate the presence of transformer damage that would be aggravated by re-energizing the transformer. The current differential and gas protection is therefore connected to operate the lockout relay.

Figure 1.
Traditional Lockout Relay

The lockout relay contains a trip coil that typically unlatches a spring that mechanically forces the relay's contacts to changeover. A normally open contact of the latching relay is included in each breaker trip circuit, disconnect open circuit, and each transfer trip send circuit required to trip the zone. A normally closed contact of the latching relay is included in each breaker close circuit and each disconnect close circuit to prevent the breaker/disconnect from being closed by any electrical means. This is necessary as breaker trip circuits are set up such that they are disabled when the breaker is open, allowing the energization of the close circuit to close the breaker. As soon as the breaker closes, the trip circuit will be re-enabled and the breaker will open, but by then the additional damage is done. Figure 2 shows a typical circuit breaker control schematic diagram.

The original intent of lockout was that on operation, maintenance or operating personnel would inspect and repair as required the locked-out zone, and when clear, would reset the lockout allowing operators to place the element back in service.

Resetting a lockout relay of the style shown in Figure 1 was by rotating the relay's pistol-grip handle to change back the contacts and recharge the mechanical spring.

However in recent decades, it has become normal to remotely control substations, resulting in the absence of on-site personnel to reset a lockout in an emergency situation, or where post-fault switching has separated the faulted element from the lockout zone. Thus many lockout relays are equipped with electrical reset facilities, which can be activated by the operators via SCADA systems. At least one utility is employing schemes that automatically reset the lockout 0.5 seconds after tripping, reducing the lockout relay's function to a simple zone trip auxiliary. Many utilities do not use lockouts at all, relying on operator administrative procedures or interlocks in the HMI computers to prevent an element from being re-energized inappropriately.

3. Lockout Core Requirements and Critical Features

The core requirements and critical features required of existing lockout schemes must be captured in any new design, and are listed in [1]. These are restated in a somewhat simplified form here:

1. Zone Based Lockout: Each protective zone that implements lockout has its own lockout state, not combined with others. For example, if a transformer differential relay trips, it sets a lockout state for the breakers that isolate the transformer. If subsequent to, or as a result of the tripping operation, one of the breakers fails, the breaker failure function sets the lockout state for the zone on both sides of the failed breaker, so that the failed breaker and all the other breakers or transfer trip channels used to isolate it are tripped and locked out.

2. Local and Remote Indication: Means are included for operators to determine which of these individual lockouts are in effect, so the cause can be checked and remedied for each.

3. Close Inhibit: A breaker cannot be closed as long as any lockout is still in effect, even if some lockouts applied to it have been reset.

4. Loss of Protection System Power: Momentary or sustained failure of the controlling relay or of power to any part of the system subsequent to tripping cannot possibly enable closing of a locked out breaker. In other words, even if some or all of the P&C system is de-energized, and then later reenergized, all the lockouts that were in effect are continuously maintained in effect.

5. Single Procedure Reset: The resetting of a particular lockout has a single procedure – all the affected breakers, channels, and other systems are reset as a group with respect to each zone lockout when that resetting procedure is executed. The operator does not have to find and reset the lockout at each of the many protection relays, breakers, or channels.

Note that this list does not include maintaining the closure of the trip contacts. The state of the trip contacts is irrelevant when the breaker is locked out, as the breaker auxiliary contact opens the trip circuit in any event. The construction of traditional lockout relays holds the trip contacts closed as an incidental consequence of their design.

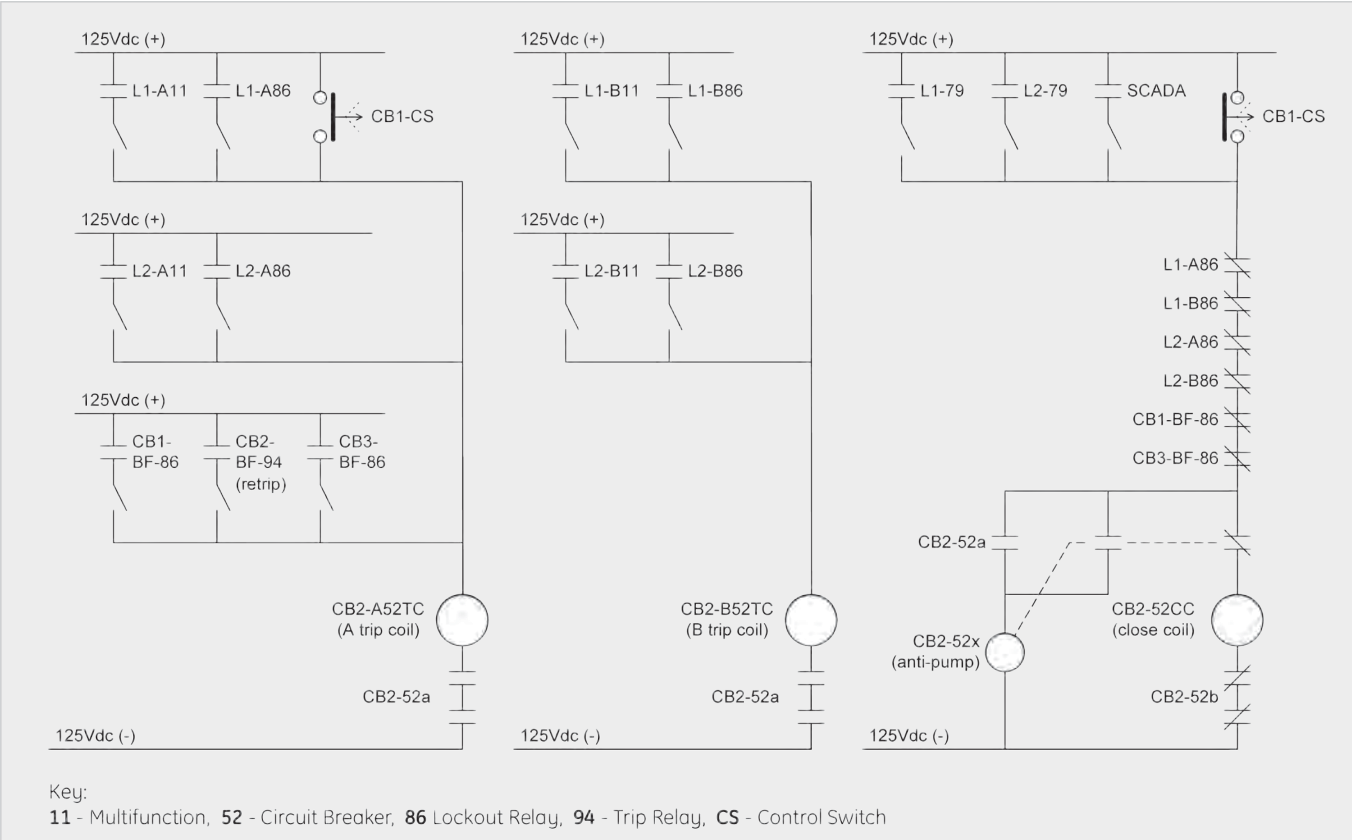


Figure 2.
CB2 Conventional Control Circuit with Lockout

4. Communications Based Protection and Control Systems

Due to pressure to continuously reduce costs, the accelerating pace of aging infrastructure replacement, shrinking workforce, and other factors, utilities are being driven to consider alternatives to the traditional ways of designing, constructing, testing and maintaining protection and control systems, of which lockout is a part. An alternative technology that is rapidly gaining global acceptance is communications based protection and control systems. With this technology, a single communications link, typically an optical fiber, replaces scores of individual copper wires and their associated infrastructure.

A popular protocol for communicating between the various protection and control components is defined in international standard IEC 61850. This standard envisions two distinct communications networks: station bus and process bus. The station bus network uses Ethernet to support communications between relays, station computer (i.e. the local control console), remote control (SCADA) systems, engineering workstations, clocks, data archival systems and so on. The process bus network also uses Ethernet, but to support communications between relays and power apparatus such as current transformers, voltage transformers, circuit breakers, disconnects, power transformers, and so on. The chief challenge of process bus is the communication of sampled values of the CT and VT waveforms, with sampling at rates of the order of 5kHz, and the precise timing of these samples to the neighborhood of ten microseconds. Latency and throughput are much more critical on process bus than on station bus.

A large number of projects have already been implemented using IEC 61850 station bus, such that this technology can be considered proven. The early adopters are now turning their attention to process bus applications. As process bus implements among other things the communications between relays and breakers, and as the lockout function consists of relays locking out breakers, any universally applicable process bus solution will have to support lockout functionality.

To illustrate how a process bus based protection and control system can readily implement lockout functionality, an example is contained later in this paper. However, to appreciate this example, the reader needs to first understand at a high level how the particular process bus protection and control system used by the example operates.

That system is the HardFiber Process Bus System [2], which is described in the following sections.

5. The HardFiber Process Bus System

The protection and control system presented in this paper is based on an architecture that incorporates application-driven requirements for performance, maintainability, expandability and reliability through the use of remote I/O devices to collect CT/VT signals and process control and status signals [2,3]. In the presented system, these remote I/O devices (Bricks), fulfill the role of IEC 61850 merging units [4].

The IEC 61850-9-2 sampled value output of each Brick is connected via pre-terminated fiber cable to a cross connect panel that directs the appropriate signals to each relay.

In reference to Figure 3, the system includes Bricks mounted at the primary apparatus, relays, pre-terminated cables, and fiber cross connect panels for patching from Bricks to relays.

The Bricks are designed to interface with signals typically used for substation automation and protection as close to their respective origins as practical, including AC currents and voltages from instrument transformers, breaker status and alarms, breaker control, disconnect switch status and control, temperature and pressure readings, and so on. The Bricks are designed for harsh environments including temperature extremes, shock and vibration, electromagnetic compatibility, sun exposure, pressure washing and exposure to salt and other harsh chemicals [8] (Figure 4).

Each Brick contains four independent digital cores, each composed of a microcontroller with individual bi-directional (bi-di) fiber links. Each core provides dedicated point-to-point communications with a single relay using messages conforming to IEC 61850-8-1 (GOOSE) and IEC 61850-9-2 (Sampled Values). These cores share common input/output hardware, implementing a fail-safe hardware design strategy that ensures total isolation and independence of the digital cores.

To improve reliability and to facilitate design, construction, testing and maintenance, the system is designed to be as simple and modular as possible. Bricks are designed such that they have no stand-alone firmware, individual configuration files or data processing algorithms; their sole function is to be a high-speed robust IEC 61850 interface to the switchyard. The system configuration, in this case the specific mapping of relays to their associated Bricks, is handled purely in the physical domain through the provisioning of individual dedicated Fiber optic connections.

The configuration for individual protection applications is relay-centric, exactly as it is today. All process inputs are always sent from each Brick to all of the connected relays and all valid commands are accepted from the connected relays. The relays themselves determine which subset of the received collection of signals will be consumed internally for protection algorithms and logic schemes. Similarly the relays generate the specific commands to be communicated to specific Bricks. Firmware management is the same as today – entirely at the relay level; the specific cores within each Brick automatically inherit whatever firmware is required from the connected relay.

Cross connect panels are used to land and organize the outdoor cables, and to distribute and individually fuse the DC power to the Bricks (Figure 5). Standard patch cords are used to accomplish "hard-fibering", making all the necessary IEC 61850 connections between the relays and the merging units as dictated by the station configuration on a one-to-one basis, without the use of switched network communications as detailed in Figure 5.

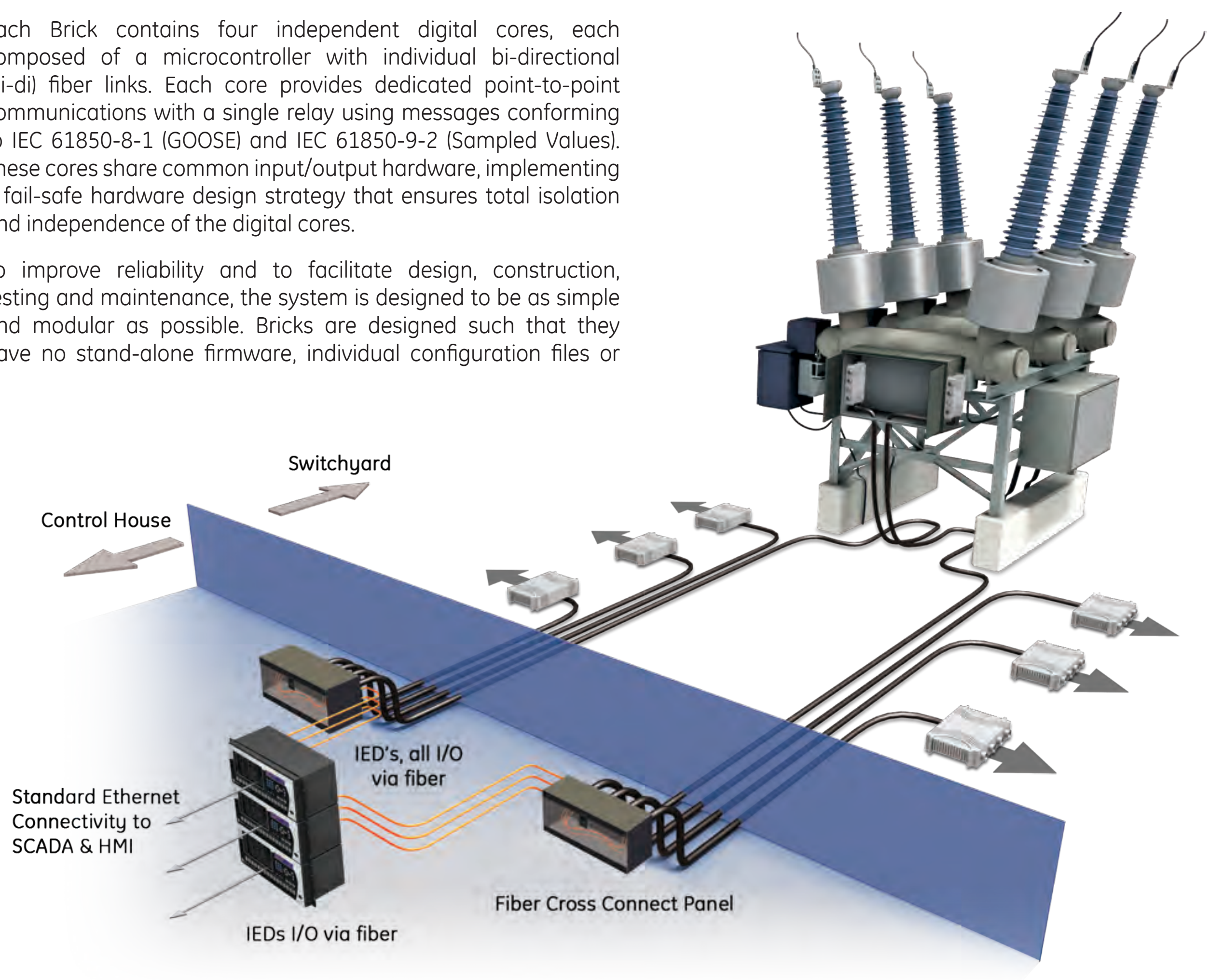


Figure 3.
HardFiber process bus architecture

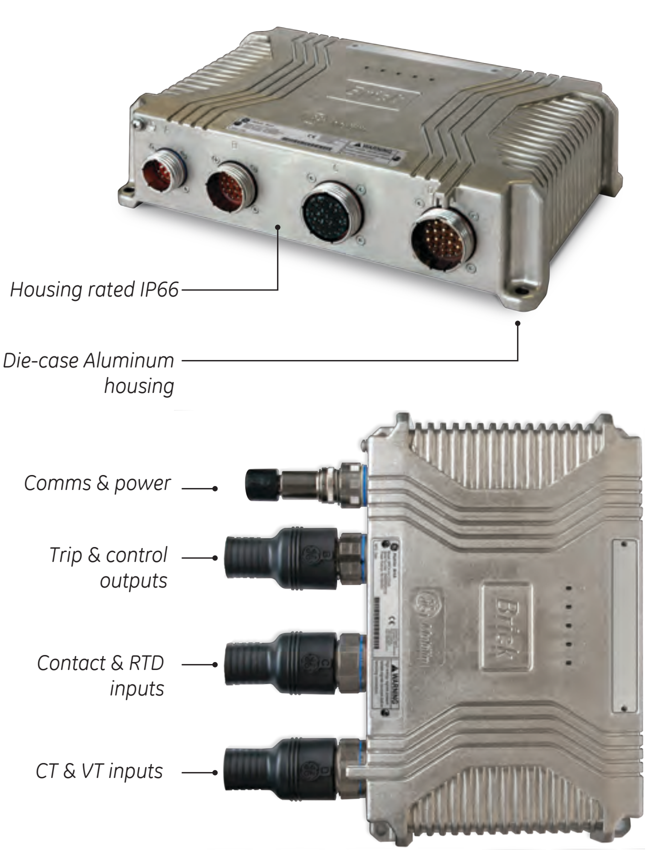


Figure 4.
Brick - rugged outdoor merging unit

Figure 5.
Fiber communication cross connect panel

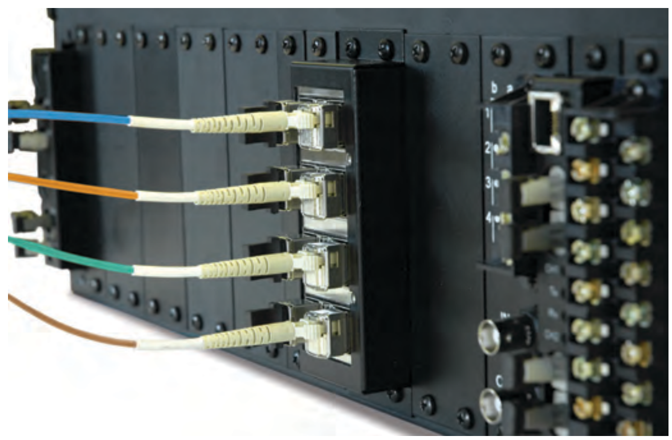


Figure 6.
Brick - Connections on a UR-series relay

The system is currently implemented on the existing GE Multilin Universal Relay platform, which supports all typically required applications. An option module provides each relay with eight optical Fiber ports so the relay can directly communicate with up to eight Bricks (Figure 6). These maximum connectivity numbers have been selected upon careful analysis of substation topologies and required data traffic patterns [3]. As such, the 8/4 connectivity covers most typical applications. Each relay provides protection for one zone, conforming to established protection philosophies. It receives the signals to perform its function over secure and dedicated direct hard-fibered links to each of the associated Bricks. The completely deterministic data traffic on these dedicated links allows the use of a simple and robust method for synchronization of samples whereby each relay controls the sample timing of the connected Brick digital cores over the link without relying on an external clock or time distribution network.

The point-to-point communications architecture provides a major dependability and security advantage over packet switched network architectures. The lack of Ethernet switches, and their associated failure mechanisms provides a dependability advantage. Although the system dependability problems associated with switches may be largely overcome through switch redundancy, the

Brick order code	Brick inputs and outputs							
	CONNECTOR D			CONNECTOR C		CONNECTOR B		
	AC CURRENTS		AC VOLTAGES	CONTACT INPUTS	RTD/TDR INPUTS	CONTACT OUTPUTS		
	1A	5A				SSR	Latching	Form-C
BRICK-4-HI-CC11	8	---	---	3	18	4	1	2
BRICK-4-HI-CC55	---	8	---	3	18	4	1	2
BRICK-4-HI-CV10	4	---	4	3	18	4	1	2
BRICK-4-HI-CV50	---	4	4	3	18	4	1	2

Table 1.
Brick process I/O capacity

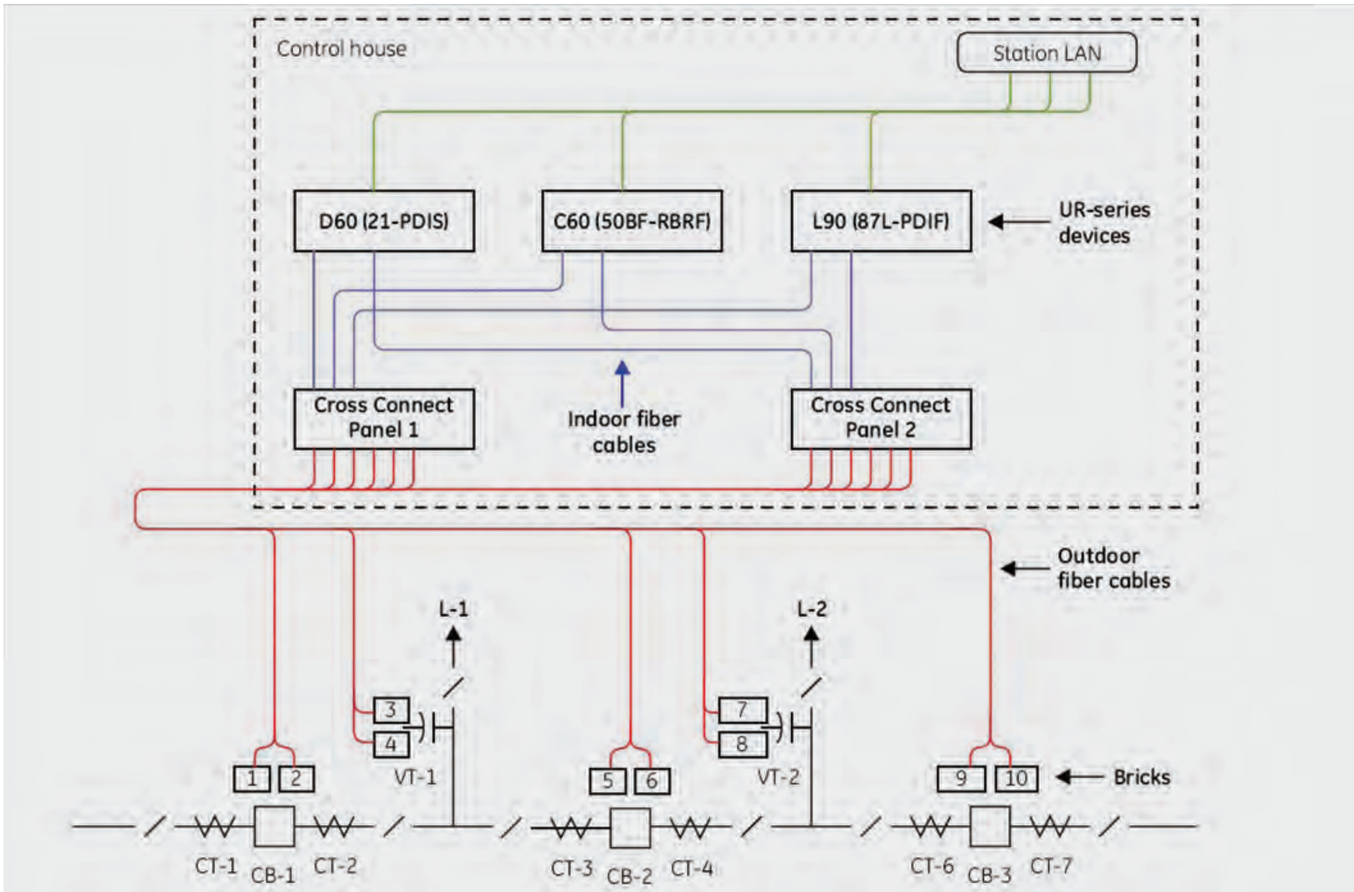


Figure 7.
Example system illustrating the architecture

redundancy adds problems in terms of system testing, and increases the number of non-dependability impacting failures that must be attended to. It is important to note that the total number of transceivers is comparable, due to the limited number of Bricks a relay needs to interface to with a practical switchgear topology.

The direct relay to brick communications architecture, without intermediate switches, makes this process bus architecture essentially immune to cyber security threats as there is neither need nor mechanism for external access.

6. Architecture

The set points for all anti-islanding protection elements are based on standard settings provided by Hydro One, a fault study performed by Hydro One, and a study performed by GE Multilin for setting the Rate-of-Change-of-Frequency (ROCOF) element. See the table below. All protection elements trip the generator circuit breaker, initiate a fault report, initiate an oscillography record, and an initiate an event report. The protection must detect all islanding conditions to satisfy utility requirements.

The example in Figure 7 illustrates the architecture of the system. A second system not shown provides a completely redundant protection system. In this example, duplicate Bricks are employed on each circuit breaker and on each bank of voltage transformers. Each circuit breaker Brick (numbers 1, 2, 5, 6, 9 and 10 in the figure) acquires the three-phase bushing CTs on each side of the breaker, breaker position and any alarm contacts, as well as outputs to trip and close the breaker. The Voltage Transformer Bricks (numbers 3, 4, 7 and 8 in the figure) inputs the three phase VT signals and line disconnect position, as well and outputs to open and close the line disconnect.

As is apparent from this figure that to perform their protection function, the relays need to interface with several Bricks installed at different locations within the switchyard. For instance, the D60 line distance protection relays [5] need to communicate with the Bricks on two breakers and one VT. For this reason, the relay has eight optical fiber ports, allowing each to connect to eight Bricks. Conversely, Bricks will need to interface with several different relays. For instance Brick 5 on the center breaker needs to communicate with the zone protection relay on each side of the breaker and the breaker failure relay. Thus Bricks have four digital cores, each of which can communicate exclusively with one relay. Fiber connections to all the process bus ports of all the relays and all the digital cores of all the Bricks are brought by indoor and outdoor multi-fiber cables to cross connect panels. At the cross

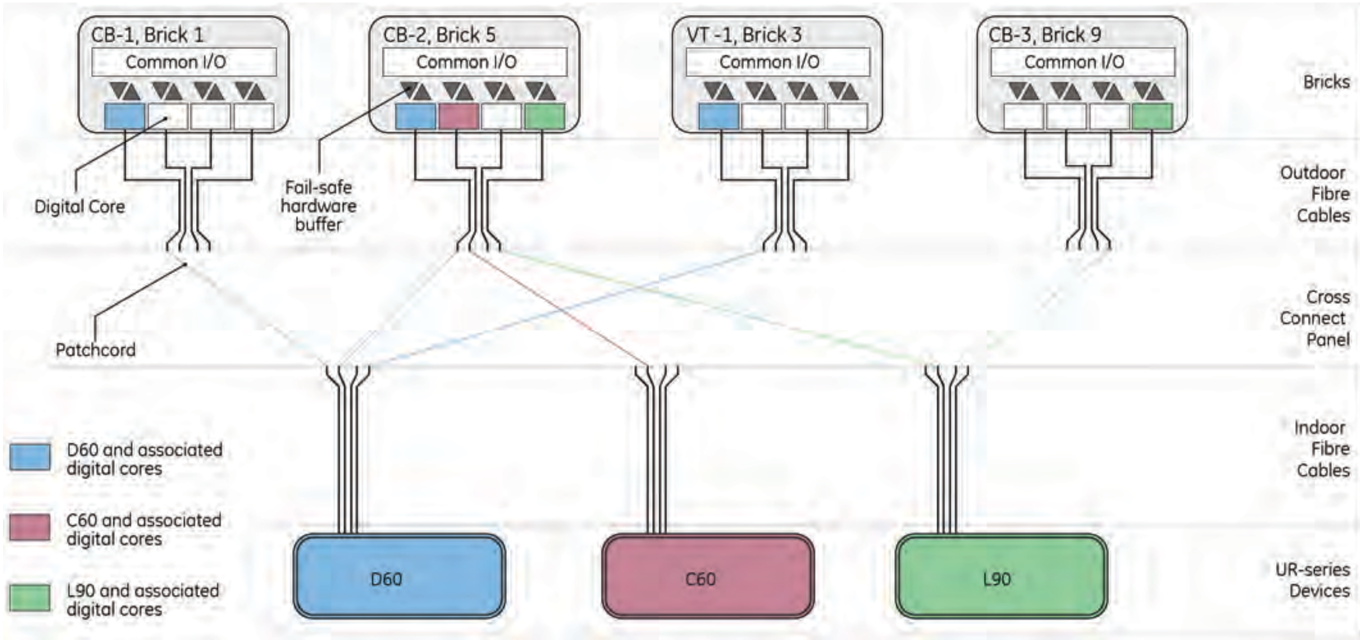


Figure 8.
Hard-fibered cross-connection of Bricks and relays

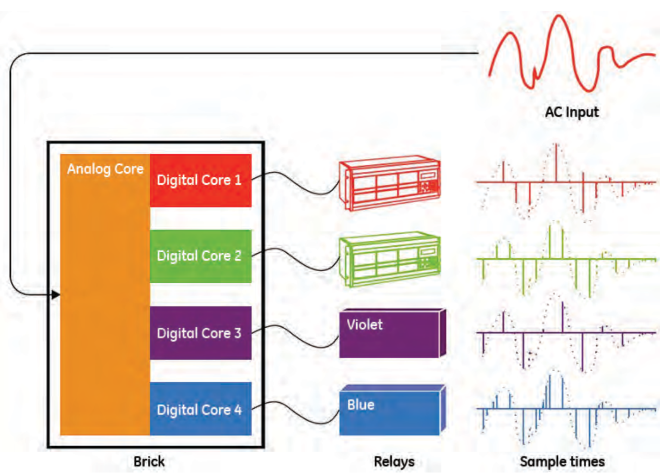


Figure 9.
Brick digital cores sampling synchronously

connect panels, each fiber of each cable is broken out to an LC type optical coupler. Patch cords then interconnect Brick digital cores to relay ports according to the functional requirements and configuration of the station's power apparatus. Thus continuous and dedicated point-to-point optical paths are created between relays and Bricks, without switches or other active components.

This patching or "hard-fibering" is what gives the HardFiber™ system its name [2]. This hard-fibering approach takes advantage of the fact that a relay needs to talk to only the few Bricks that have input or outputs related to that relay's function, that only a few relays are interested in any given Brick, and that the necessary relay-Brick connections change rarely, only when the station one-line changes. For those few instances where additional Brick digital cores are required, for instance for VTs on a large bus, additional Bricks can be installed sharing the same copper interface to the primary apparatus.

Figure 8 provides an expanded view of a portion of the example system. In this example, digital cores from Bricks 1, 3, and 5 are connected to the D60. A single digital core in Brick 5 is connected to the C60 [6], and digital cores from Bricks 5 and 9 are connected to the L90 [7]. Note that the choice of specific cores and specific relay ports is arbitrary – Brick cores and relay ports are functionally identical.

The various relay protection and measuring elements that use AC data from multiple Bricks must have the currents and voltages at various locations sampled at the same instant. The existing method for determining the time of the samples is maintained.

Each relay contains a sampling clock that determines when samples need to be taken. In the case of the UR this clock is phase and frequency locked to the power system quantities measured by that relay, although other sampling schemes are possible. At each tick of the sample clock, a GOOSE Ethernet frame is sent by the relay to each connected Brick digital core. Digital cores sample the quantities on receipt of each frame. As the digital cores are fully independent, different relays may sample at different rates or with different phase, but as each is connected to different and independent cores, there is no conflict. Thus each relay is able to sample in a fashion optimal for its application, independently from other relays, and no external clocks are required.

7. A Practical Process Bus System Lockout Implementation

We will now demonstrate how such a process bus protection and control system may be configured to meet the previously stated core requirements and critical features.

For this demonstration, we will use one diameter of a substation with a breaker-and-a-half arrangement, as shown in Figure 10. In this figure, only those facilities necessary to illustrate the scheme are shown: dual redundant line relays for each of lines L1 and L2, and dual Bricks for each of circuit breakers CB1, CB2 and CB3. Not shown, to simplify the description, are the bus protections, the CVT's Bricks, and the line protection pilot communications facilities. The line relays are designated by the combination of the protected element's designation, the protection system "A" or "B", and the function code (11 – multifunction relay). Thus L1-A11 is the "A" system multifunction relay protecting line L1.

The line protections each consist of a L90 current differential in the "A" system and a D60 distance protection in the "B" system. Each of the line relays also includes breaker failure protection for each of the two breakers in its zone. This results in four breaker failures schemes per breaker, much more than required, but there is no additional hardware cost, and the inter-relay communications for initiating breaker failure is simplified.

The control circuit for circuit breaker CB2 is as shown in Figure 11. The circuits for the other circuit breakers are similar. Note how little wiring is required in comparison to the copper based equivalent shown in Figure 2. Not only is there less wiring, but except for the station battery connections, it is all in the breaker – there is no copper cabling back to the control house.

Each Brick's Solid State Relay (SSR) output contact designated OUT1 is connected to operate either the "A" or the "B" breaker trip coil, so that either Brick can trip the breaker independently of the other. In the single close circuit, the two Bricks' OUT4 SSR output contacts are connected in parallel, and their latching output contacts connected in series, such that either Brick can close the breaker provided that both the latching contacts are closed. If either latching output contact is open, it is not possible to electrically close the breaker. As we shortly shall see, these Brick latching contacts are a key part of the lockout scheme.

The Brick latching output is a magnetically latched bi-stable relay with an electromechanical contact. The magnetic latching results in the contact staying in its last commanded state should the Brick loss power or communications with the relay(s).

The Brick accepts separate open and close commands from all of the connected relays to operate this contact, but hardware interlocking in the Brick enforces open dominance. That is to say, if at a given moment both open and close commands are being received, the contact will open. If neither open nor close commands are being received, the contact remains in its last commanded state.

The lockout logic contained in the L1-A11 line relay is as shown in Figure 12.

Similar logic is implement in all the relays, including the "B" system relays and other relays not shown in Figure 10 such as the bus protection relays.

The central part of this logic scheme is the non-volatile, set-dominant latch designated L1-A86 (line L1 "A" system lockout). Connections not shown send the status of this latch to the HMI via

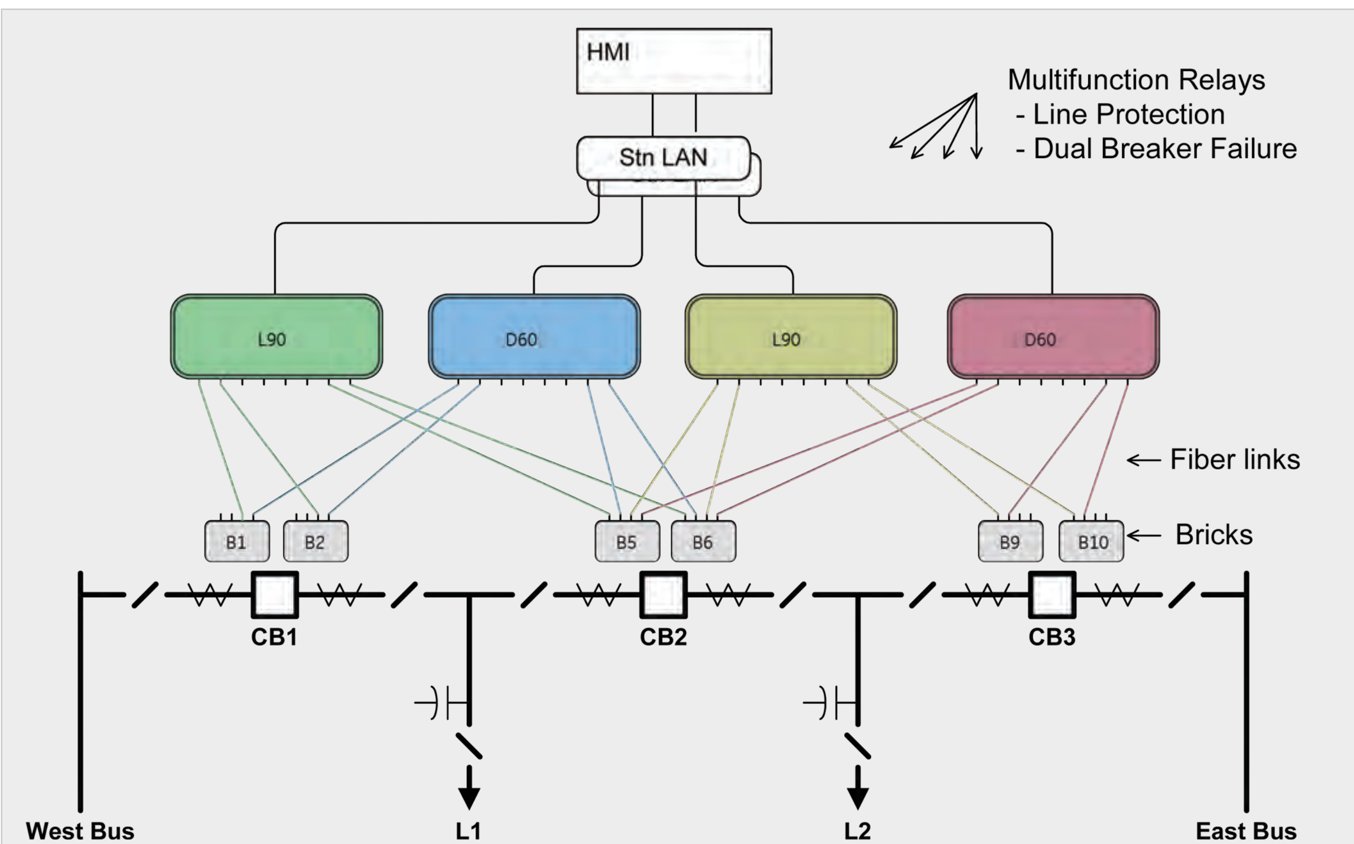


Figure 10.
HardFiber Interconnections for L1 and L2

the Station LAN, giving operators indication of which lockouts are active at any given time. This latch is set by the "OR" of any of the conditions that ought to lockout line L1. These include:

- Any of the measuring elements that indicate a permanent fault on the line, such as timed zone 2 distance and line pickup. These are collected by the Trip Bus 2 element, and appear as the TRIP BUS 2 OP operand. Note that in UR-series devices, a "Trip Bus" is an element that allows aggregating outputs of protection and control elements, and does not in this case have any association with the station's bus bars, only the line protection.

- CB1 breaker failure protection operation. Breaker failure element number 1 is used for CB1, and its output appears as operand BKR FAIL 1 TRIP OP.

- A lockout command from the CB2 breaker failure in either the "A" or "B" L2 relays. These commands are here communicated via a HardFiber feature known as "Shared I/O" [2]. With shared I/O, the originator, in this case one of the L2 line relays, sends a command to a virtual output of the Brick. This virtual output is similar to the SSR contact outputs, except that there is no physical contact. The Brick sends the status of this virtual contact back to all connected relays in the same way as it does physical contact inputs. Thus the Brick can act as a mailbox for inter-relay protection communications wherever two relays share a Brick. The received shared I/O status appears as "SI" (Shared Input) operands, in this case SI1 from Brick B5 and SI2 from Brick 6.

  For redundancy, both L2 relays send the lockout shared I/O command through both of the two Bricks that the L1 relays and the L2 relays share.

- A lockout command from the CB1 breaker failure in either the "A" or "B" West Bus relays. This uses shared I/O in the same way as the CB2 lockouts from the L2 relays. In this case the lockout appears as shared inputs SI3 and SI4 from Bricks B1 and B2 respectively.

- CB2 breaker failure protection operation. Breaker failure element number 2 is used for CB2, and its output appears as operand BKR FAIL 2 TRIP OP. As can be seen in Figure 12, the output of the L1-A86 enforces a lockout condition on L1 as long as it is set, by being connected to:

- Trip and hold the trip on CB1 via SSR contact output OUT1 on both Bricks B1 and B2.

- Open and hold open the latching output contact on both Bricks B1 and B2, preventing the subsequent closing of CB1.

- Send transfer trip as long as L1-86 is set. The implementation details of transfer trip are not relevant to our discussion here.

- Trip and hold the trip on CB2 via SSR contact output OUT1 on both Bricks B5 and B6.

- Open and hold open the latching output contact on both Bricks B5 and B6, preventing the subsequent closing of CB2.

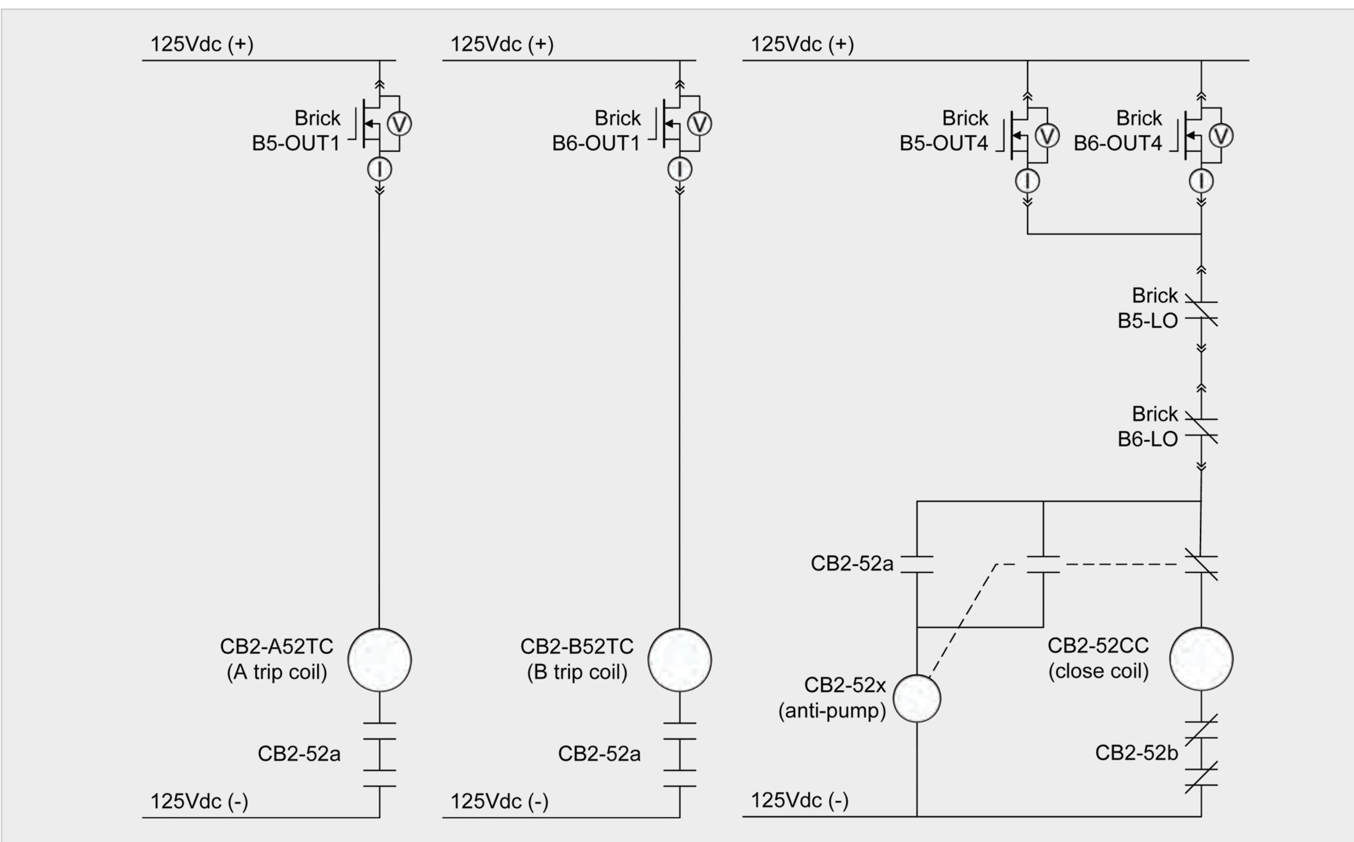


Figure 11.
CB2 HardFiber Control Circuit with Lockout

The L1-A86 latch is reset by the receipt of a GOOSE command from the HMI. Note that as the latch is set-dominant, if the initiating condition is still present when the reset is issued, it will have no effect. This command is configured in the L1 relay to appear as the remote input operand RI1. Presumably this same GOOSE will be received by the L1 "B" system relay and will reset the "B" system lockout at the same time. The resetting of the L1-A86 terminates the latching output open command. As shown in Figure 12, receipt of this GOOSE command also sends a close command to the latching outputs of all the involved Bricks. If no other relay is at that time sending an open command, the latching contact will close, and breaker closing is re-enabled.

Returning to the top of Figure 12, note that CB1 breaker failure operation also sends a lockout command to the Bus 1 relays via shared I/O through Bricks B1 and B2, just as we previously discussed the L2 and West Bus relays sent lockout to this relay.

Similarly, as shown at the bottom of this figure, CB2 breaker failure sends a lockout command to the L2 relays via shared I/O through Bricks B5 and B6.

To complete the description of Figure 12, the CB1 and CB2 breaker failure relays retrip their respective breakers. The instantaneous non-locking line protection operations, collected by Trip Bus element number 1, trip both breakers and send transfer trip without invoking lockout.

8. Response to Component Failures

The forgoing section has explained the operation of the proposed design when all components are operating normally. We now turn to the response of the system while suffering various failures.

First, consider the case of a condition that ought to result in lockout while a single protection and control system component is inoperative due to either some internal failure or being taken out of service for maintenance or repair. Referring to Figure 10, it can be seen that loss of a single Brick will still leave at least one Brick in-service on each breaker, receiving commands from both relays in each zone. Similarly, loss of a single relay will still leave one

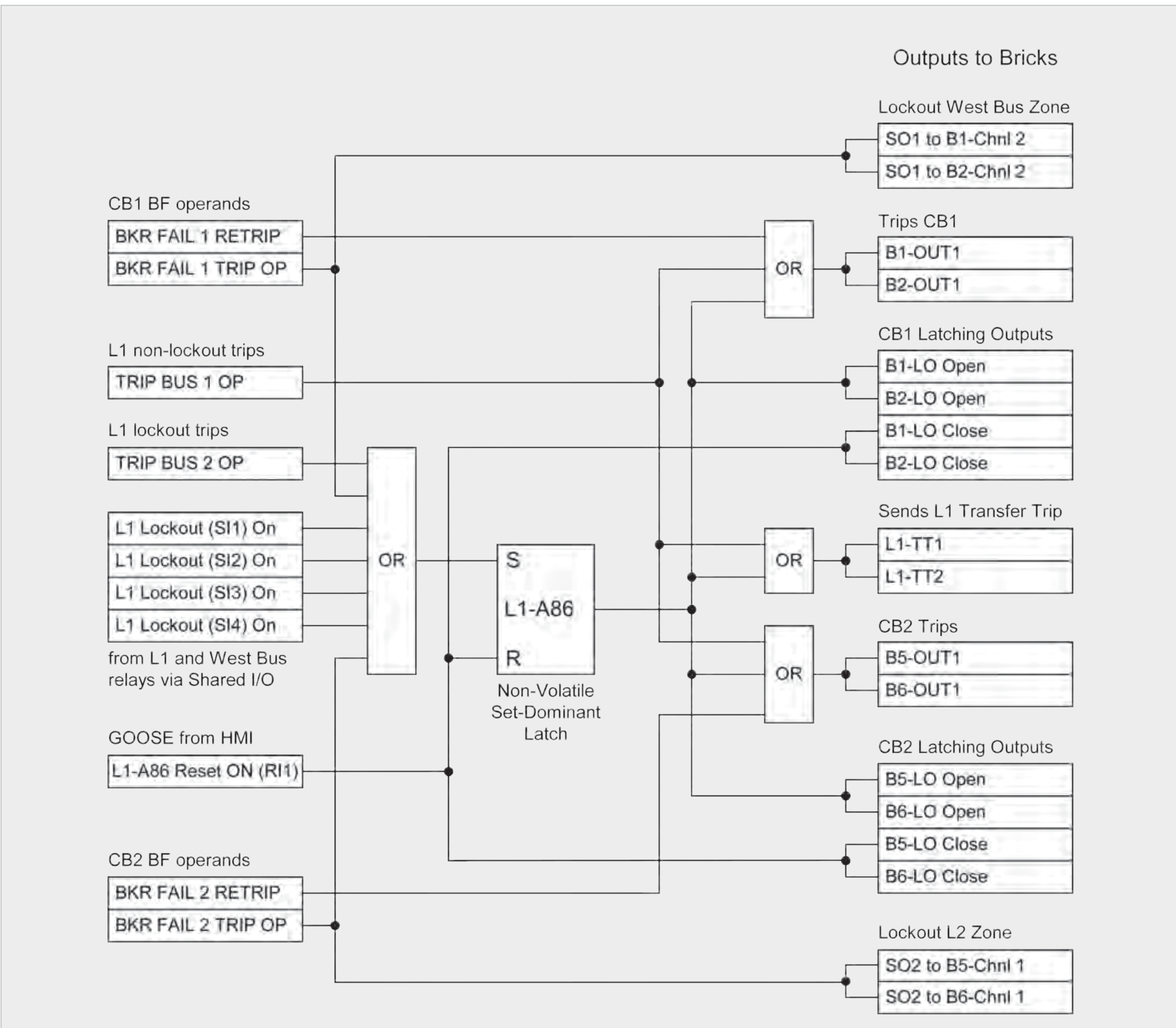


Figure 12.
L1-A11 Internal logic relevant to Tripping and Lockout

relay in-service for each protection zone. Loss of either a single indoor or a single outdoor cable is equivalent to loosing the corresponding relay or Brick. Referring to Figure 11, it can be seen that either Brick acting alone can trip its breaker and lockout breaker closing. Finally, referring to Figure 12, it can be seen that the system "A" relay does not rely on system "B", and as system "B" is similar to system "A", the converse is true, so it can be concluded that either relay acting alone can initiate lockout. Thus it is shown that the design can establish lockout with any single contingency failure. In fact, there are many cases of multiple component failure that do not impact the ability to establish lockout.

"BY RELYING MORE ON DIGITAL INTERFACES AND SUBSYSTEMS, THE SYSTEM IS MADE MORE FAIL-SAFE: IT EITHER WORKS OR IT DOES NOT"

Next, consider the case where lockout has been established on an element, and various protection system failures occur. Loss of power to one or even all of the Bricks has no impact on the pre-existing lockout conditions, as the Brick latching outputs are magnetically latched, and retain their position without power. The latching outputs also retain their position when communication with the relays are lost, and on being power up. A Brick design objective, shown effective by extensive factory type testing, was that Brick failure, vibration and shock do not result in the latching output changing state.

Even if this were to happen, it is not creditable that it occur simultaneously in both Bricks. Thus it can be concluded that a locked out breaker cannot be closed as a result of Brick troubles.

Should power to a relay be lost while in the lockout state, it will cease issuing latch open commands to its Bricks, but the alternate relay should continue to do so, and even if it does not, the Bricks latching output will not change state till specifically commanded to do so. When the relay is again powered up, as the lockout latch is non-volatile, it will simply resume sending latch open commands. If the relay is replaced with another, the new relay may not send latch open commands, but neither will it send latch close commands till initiated by the HMI. Thus it can be concluded that a locked out breaker cannot be closed as a result of relay troubles either.

9. Conclusions

This paper surveyed the history and traditional practices of lockout in electrical power transmission substations. It outlined the high-level design principles for lockout functionality, with the objective of applying them to process bus based protection and control systems.

This paper has presented a new process bus system for protection and control using IEC-61850 process bus as a technical framework. Other papers [3, 8] present the option to duplicate the remote I/O devices in the presented system in order to achieve an unprecedented level of security, dependability and availability.

Special attention has been paid to the fail-safe aspect of the design. By relying more on digital interfaces and subsystems, the system is made more fail-safe: it either works or it does not, with a greatly reduced probability of a subsystem being in a faulted yet undetected state.

As a result, the presented system can be easily argued as being more reliable compared with other implementations of protection and control systems. Rigorous self-monitoring strategy and ability to support fully duplicated I/O layer make it an excellent candidate for application in ultra-critical protection and control systems.

The implementation of the lockout principles in this process bus based protection and control system is illustrated using an example from a typical switchyard. An analysis of the system's response to various failure conditions shows that the objectives of lockout are fully met.

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Improvements in Power System Integrity Protection Schemes

Craig McTaggart
Scottish Power

Jorge Cardenas, Alberto Lopez
GE Digital Energy

Alan Bone
GSS

Abstract

As the existing transmission system infrastructure is challenged to support loads beyond original design limits, the implementation of "wide area" Power System Protection Systems (PSPS) also called System Integrity Protection Schemes (SIPS) are often needed to maintain transmission system integrity. Such a system, with stringent performance and availability requirements, has been designed and installed in the UK (in 2008), and specifically on the Interconnection between Scottish Power and National Grid. The strategy to maintain transmission system integrity is based on the determination of circuit connectivity in the interconnection and, according to pre-defined criteria obtained from different system stability studies, to selectively issue a trip command to Scottish Power generating units in less than 20 ms. This paper starts by presenting the need for the PSPS and the resulting design requirements. It discusses afterwards the architecture that resulted from the requirements and the subsequent implementation and testing issues. Actual operation and performance results, including end-to-end timing tests, will be presented. The paper concludes with a discussion of desired improvements in the architecture and new solutions that are available through the Generic Object Oriented Substation Event (GOOSE), Virtual LAN (VLAN), and priority messaging technologies that are now available through the IEC 61850 communication standard. The following conclusions were found during the project execution at Scottish Power·

Real time control schemes will increasingly play a role in maintaining the security, stability, and integrity of the electric power network. Today's digital relays – in close integration with advanced communication networks – promise to provide solutions for remediation of identified power system problems.· Implementation using commercial IEDs and configured as two identical systems operating in parallel for redundancy, the SIPS meets the performance requirements defined by system studies.

1. Wide Area Disturbance Protection

When a major power system disturbance occurs, protection and control actions are required to stop the power system degradation, restore the system to a normal state and minimize the impact of the disturbance. The present control actions are not designed for a fast-developing disturbance and may be too slow. Local protection systems are not able to consider the overall system, which may be affected by the disturbance. Wide area disturbance protection is a concept of using system-wide information and sending selected local information to a remote location to counteract propagation of the major disturbances in the power system. A major component of the system-wide disturbance protection is the ability to receive system-wide information and commands via the data communication system and to send selected local information to SCADA [4].

The relative importance of each region of vulnerability is called the vulnerability index. A larger value of the vulnerability index indicates that the region is relatively more important and can cause more serious wide area disturbances or has a higher possibility to cause the disturbances than the one with a smaller index.

"A Power System Protection System (PSPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance". Such action includes, among others, changes in demand (e.g. load shedding), changes in generation or system configuration to maintain system stability or integrity and specific actions to maintain or restore acceptable voltage levels [4].

THE GENERATION SHEDDING SCHEME WAS IMPLEMENTED BY SCOTTISH POWER TRANSMISSION TO ALLOW INCREASED POWER FLOWS WITHOUT LOSS OF STABILITY BETWEEN SCOTLAND AND ENGLAND

Power System Protection Systems (PSPS) is a relatively new concept that arrives from the need to supervise critical nodes that have a big influence on Power System performance. These take the form of automatic actions that instigate load shedding in a specific area of the network or reduction of Generation Output in order to prevent instability or overloads in interconnections that could affect the circuit or Power System stability, etc.

The corrective and emergency actions are limited to a finite number of measures. A detailed description of these measures will be provided as implementation issues for different types of disturbances are analyzed.

2. Description of the power system where the PSPS is applied

The transmission systems of ScottishPower Transmission (SPT) and National Grid Electricity Transmission (NGET) are connected by two double circuit 400kV lines. These circuits, as illustrated in figures 1 & 2 are referred to as the East Coast and West Coast Interconnectors. The East Coast Interconnector is equipped with a basic version of the PSPS which has been in service since 2001. Upgrade work to the West Coast Interconnector which uprated the existing 275kV circuit to 400kV operation resulted in the connection of four substations between the two termination points of the interconnector at Strathaven, near Glasgow (SPT), and Harker, near Carlisle (NGET).

Under exporting conditions from Scotland to England, Interconnector faults result in a surplus of generation over demand in Scotland. The transfers between the two systems are therefore limited by the post-fault transient stability limit of the Scottish system.

In order to increase the transfer capability and minimise generation constraints, a scheme to shed generation in the event of pre-defined fault scenarios was identified. The need for the scheme to be in service and the amount of generation to be shed for various contingencies depends significantly on the transmission load flow pattern. Therefore the scheme is capable of being armed to disconnect generation according to the prevailing system status and generation pattern, following line faults or to accommodate planned outages, thus increasing transfer capability.

This goal was achieved by installing individual schemes for the Strathaven – Coalburn, Coalburn – Elvanfoot, Elvanfoot – Moffat, Moffat – Harker, Strathaven – Elvanfoot, Elvanfoot – Gretna and Gretna – Harker circuits (Moffat is a future substation to be connected at a later date). Each circuit scheme is duplicated and the initial criterion is to detect loss of Power Flow Path (Line End Open or LEO) on one or more circuits. Analogue measurements are not used in the initial scheme.

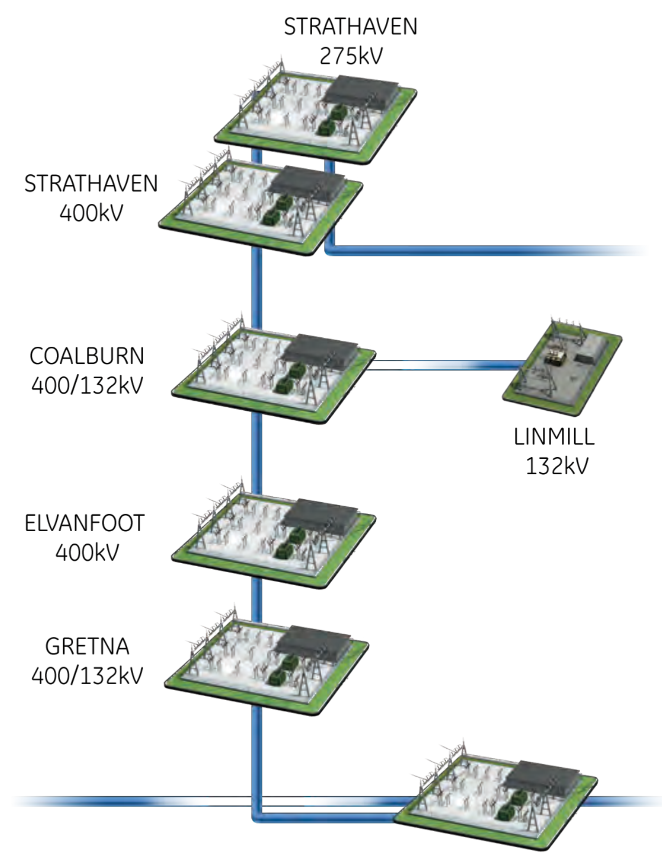

Figure 1.
West Coast Interconnector

The generation shedding scheme was implemented by Scottish Power Transmission to allow increased power flows without loss of stability between Scotland and England.

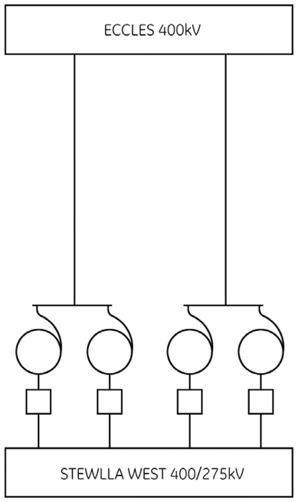

Figure 2.
East Coast Interconnector

3. System requirement

- The maximum permissible time between protection trip relay operation at any remote site and the issuing of a generator trip command at Strathaven 400kV is 25ms, including an assumed communications system latency of 5ms.
- It must be possible to send five commands between sites simultaneously with no loss of performance.
- The inter-site signalling system must comply with PROT-16-009 Issue 1 [7] for Intertripping equipment.

4. System Design

The reliability criteria for transmission planning and operation in Great Britain is the N-d criterion, which requires a transmission system to be developed and operated at all load levels and to meet the most severe double circuit contingency in addition to any scheduled outages. As multiple contingencies are beyond the planned and operational limits of a power system, the occurrence of any multiple contingencies may lead to overloading and cascading trips on the network.

Strathaven 400kV is the scheme 'hub'. Line End Open decisions are made at each site (two feeders and a bus coupler or four feeders depending on the substation) and signalled individually to Strathaven 400kV. The overall scheme logic is performed at Strathaven 400kV and the Operational Trip decision made at Strathaven 400kV is signalled to generators using existing signalling equipment (HSDI-3).

Logical Combinations of circuit breaker position and trip relay status provide Line End Open tripping initiations. In order to minimize the operating time of the scheme, protection operations are considered as Line End Open. The circuit breaker positions are monitored to capture manual opening or the operation of circuit breaker fail protection of an unmonitored circuit, which causes the monitored circuit breaker to open.

Once the scheme performance requirements had been established, SPT developed the concept of employing IEC61850 GOOSE to collect the signals for processing in scheme logic. The scheme logic was agreed with NGET and the logic was then implemented in the GE UR IEDs.

5. Physical Architecture

Having done the engineering analysis as to the device inputs and outputs, communication requirements, and system controller requirements, the final step in the implementation process was the development of the physical architecture. This drawing shows the number of devices required per substation, I/O requirements, communication channels and redundancy, system and device redundancies, time synchronization, controller locations, HMI facilities, etc. This physical architecture allows for a final review before sending the system out for final design.

In addition, the physical architecture provides a mechanism for future explanation and operator training.

In line with standard practice in the GB Transmission system, a duplicated scheme is provided:

- Each scheme (System 1 & System 2) is a full communication scheme where the final trip decision is based on circuit status from remote sites gathered using the IEC 61850 communication protocol and using a Master IED to provide the scheme logic with a link to the trip system.
- Each system is also a hybrid communication/hardwired scheme where the final trip decision is based on circuit status from remote sites gathered using conventional IED relay contacts and opto-inputs.
- Plant status inputs to each system are provided by four auxiliary contacts, two of each state, and the scheme logic checks for discrepancies. Only if the four contacts are in the correct states will the plant status be recognised.
- The Direct and Remote I/O communications both employ 32-bit CRC and comply with international standards for protection communications.
- There are extensive isolation facilities which are supervised and annunciated. These use interfaces familiar to operations staff, namely switches and removable links.

The relays used in each substation were IEDs with the following capabilities:

- Protection: Out-of-step tripping, Power Swing Blocking, Under- & over-frequency, Rate of change of frequency, Sensitive Directional Power, dP/dt, dV/dt, Overcurrent, Under- & over-voltage.
- Control: Open pole detection, Synchrocheck, Programmable Logic Control, Add, Subtract, Compare, Select.
- Communication: Peer-to-peer via Ethernet, Peer-to-peer via SONET, G.704, RS422, C37.94, Fiber, Flexible communications. Architectures, Telemetry with 8-bit resolution, Respond to remote & local data.
- Monitoring: Synchrophasors (PMU – only in the Main 1), Metering of Voltage, Current, Power, Frequency, Energy, SOE, DFR, etc.

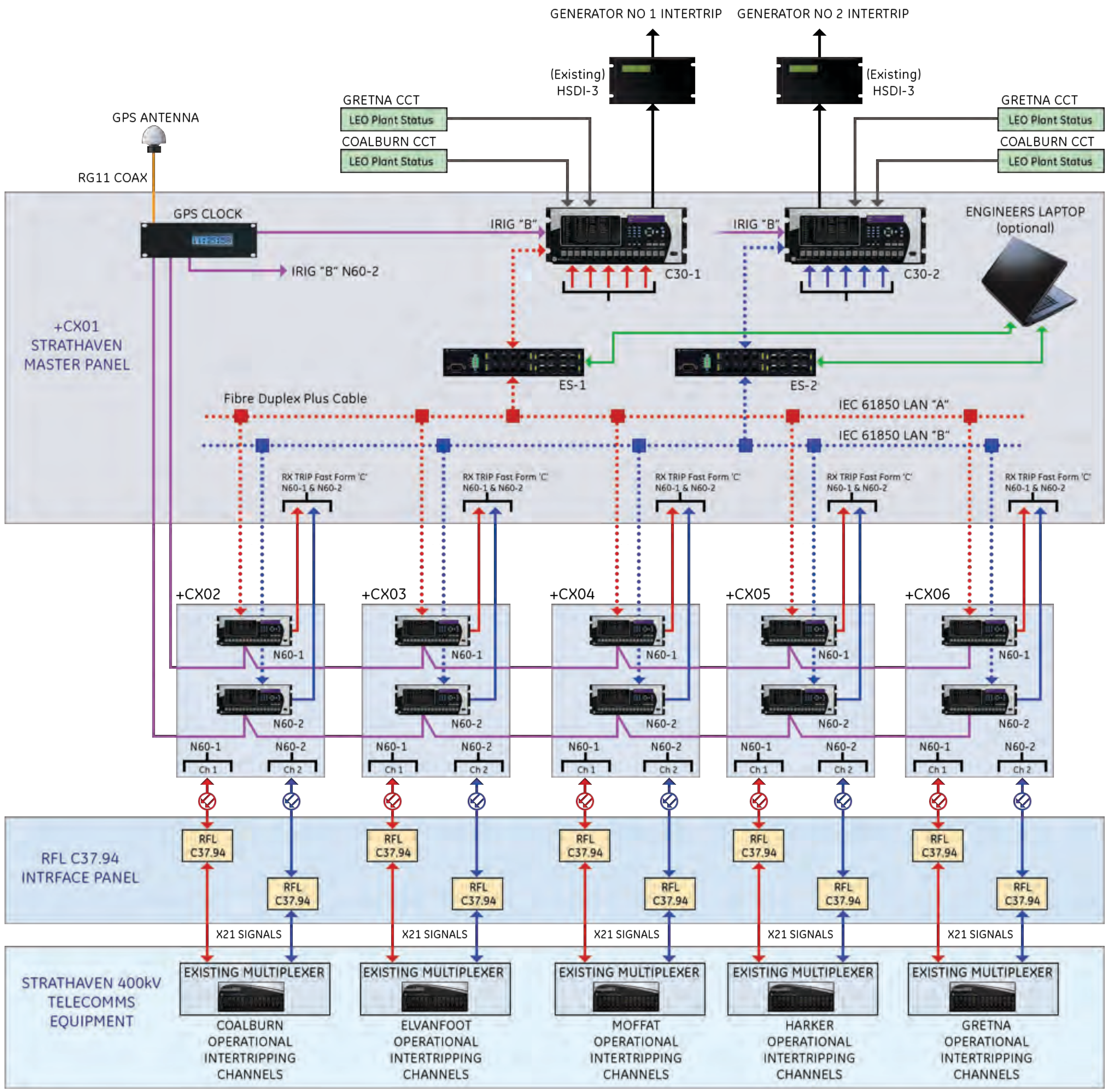

Figure 3.
Physical Architecture. Wide area generator rejection scheme.

The Master IED used at Strathaven has only Control & Communication features.

The system is designed with 10 IED units for System 1 and 10 units for System 2. Only System 1 has PMU capability. The CT and VT inputs are available at the relay panel terminal blocks but are not yet connected to the primary plant. The PMU capability has been provided to facilitate future development of the scheme and to support SPT's future wide area monitoring strategy.

The IEDs were used on the 400kV operational intertrip system for the West Coast Interconnector between Scottish Power and National Grid.

The IEDs transmit line end open signals via direct I/O from remote substations to receiving IEDs at Strathaven substation using C37.94 communication system in a redundant scheme.

At Strathaven all IEDs are connected via hardwire and Ethernet to the Master IED unit. Each IED sends signals via hardwire and remote I/O (GOOSE).

Combinational logic is used in the Master IED to route the signal through to the HSDI voice frequency intertrip equipment to trip the selected Scottish generators.

This is the first system in the UK to be in service and tripping at 400kV using IEC 61850. It has been in service since July 2008.

The system is being extended this year with a completion date of October 2009, by adding a further panel with IEDs to permit the tripping of additional Scottish generators. A Master IED which will act as a SCADA interface unit will be also added. This will take IEC 61850 commands from the Operational Control Centre (OCC) via a

Microsol RTU with an IEC 61850 interface card. It is a trial installation to observe the merits of IEC 61850 SCADA control. ICD files will be developed for this task.

6. System performance

The reliability criteria for transmission planning and operation in Great Britain is the N-d criterion, which requires a transmission system to be developed and operated at all load levels and to meet the most severe double circuit contingency in addition to any scheduled outages. As multiple contingencies are beyond the planned and operational limits of a power system, the occurrence of any multiple contingencies may lead to overloading and cascading trips on the network.

REAL TIME CONTROL SCHEMES WILL INCREASINGLY PLAY A ROLE IN MAINTAINING THE SECURITY, STABILITY, AND INTEGRITY OF THE ELECTRIC POWER NETWORK

There are three tests that are performed, namely:

- Scheme Checks
- Logic Tests
- End-to-End Tests

Total trip time was less than the expected : On average, the total trip time was always less than a cycle (20 ms) using hardwire inputs/outputs or using GOOSE (IEC61850) for final trip schemes.

7. Implementation issues / New solutions

With the C37.94 communication system, each measuring relay had one C37.94 – 64,000 bps port which was configured to transmit information on detection of a Line End Open condition.

As stated above, the Control Engineer's decision to 'arm' the system is based on prevailing generation patterns and network conditions. The system's scheme logic includes the flexibility to accommodate system outages. Commands from the OCC modify the scheme logic to allow the scheme to respond to changing network connectivity and generation patterns.

8. Operational experience

The system has been in service for almost two years now and has had no false operations, it has not been called upon to operate, and correctly did not operate during a recent trip-out of the plant.

9. Future enhancements

The potential, to improve power system performance using smart control instead of high voltage equipment installations, seems to be great. The first step should aim at achieving the monitoring capability, e.g., a WAMS (Wide Area Measurement Systems). WAMS is the most common application, based on Phasor Measurement Units (*).

Since this system has been installed, a new solution space has been made available through the communication capabilities of the IEC 61850 GOOSE to transmit and receive Digital and Analog Signals.

(*) Phasor Measurement Unit (PMU) – Device that records phasor quantities and accurately references them to a standard time signal. (See IEEE Standard 1344-2006 for more details.)

10. Conclusions

- Real time control schemes will increasingly play a role in maintaining the security, stability, and integrity of the electric power network. Today's digital relays – in close integration with advanced communication networks – promise to provide solutions for remediation of identified power system problems.
- Implemented using commercial IEDs and configured as two identical systems operating in parallel for redundancy, the SIPS meets the performance requirements defined by system studies.

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Stimulus Funds and the Smart Grid: The First Thing We Need to Rebuild is Our Approach

John McDonald
GE Digital Energy

Within our industry, we've been talking about a smarter grid for just about as long as any of us can remember – long before anyone coined the term smart grid. We've been developing solutions and installing them here and there all over the world, making slow and steady progress. But things are about to change fast. With stimulus funding and growing public understanding, we have a phenomenal opportunity to fast-track smart grid rollouts and make great strides in improving our transmission and distribution systems. But the first improvement we need to make is how we plan, manage and integrate new smart grid technologies into our infrastructure. If we move forward with our current siloed way of doing business, we won't maximize the value of stimulus dollar investments.

1. Holistic Means The Whole Organization

Utilities must break down the barriers between departments and functions. The independent, function-based decision-making of the past 100 years is the enemy of smart grid success. Siloed thinking can hinder smart grid implementations by creating disparate solutions and investments of limited resources into redundant systems. An optimized smart grid is a holistic approach to energy delivery. There are no territories, secrets and sacred cows. Departments that interacted little with each other in the past must become day-to-day partners.

It is a huge operational change that can be effectively led only from the top levels of a utility. The CEO and C-level executives must mandate the change. They need to organize cross-functional work groups and reward holistic thinking to change utilities' culture for smart grid success.

Supplier organizations also need to broaden their vision. Instead of focusing solely on the solutions they offer, they must understand how their products and services fit in to the entire smart grid. Holistic supplier thinking will result in more functional, flexible and practical products and services. Holistic suppliers, and the utilities that choose their products, will have a business advantage.

COMPANIES THAT EMBRACE THE NEW REALITY AND CHANGE HOW THEY DO BUSINESS WILL GET THE MOST FOR THEIR STIMULUS BUCK

2. It's Time For A Clear Roadmap

Another vital responsibility for C-level executives is establishing and sharing the utility's smart grid objectives and direction throughout the enterprise with a smart grid roadmap. Working together, the executive suite can outline a methodology for evaluating, approving, and purchasing smart grid products to ensure that purchases are planned, vetted and discussed across functions. This will also help ensure that stimulus funds deliver maximum value per dollar.

A smart grid roadmap needs to touch on these four guideposts for success:

1. **Setting Goals.** What are the utility's pressing issues? Determined by regulations, equipment, economic factors and business issues, your smart grid plan needs clear, measurable goals.
2. **Understanding the available technology.** You need to know what's real, what's vaporware and what's on the horizon. Only then can you set your direction and begin to fashion an overall improvement plan.
3. **Discussing industry standards.** Standards are emerging for technologies across the smart grid. Knowing the standards status helps you choose solutions that are scalable and flexible. If you ignore standards, you risk installing solutions that will become obsolete and expensive to maintain.
4. **Creating a solid business case.** Ensuring there is a clear value proposition created, with a stringent vetting process, ensures you make an investment that improves your operation in meaningful, important ways.

The ideal roadmap should also focus on city-scale technology deployments rather than small pilot projects. While there is a pace for pilot projects to test functionality, they cannot test the technology or human behavior on a scale large enough to gauge success. The technology exists and it's proven; it's time to roll it out.

3. A New Measure of Operation Success

Siloed system implementation also leads to siloed reporting, metrics and evaluation. Therefore, Department A could consider a new system rollout a success, although it missed its potential to deliver great value for the objectives of Department B.

For example, a utility might have one team evaluating and installing an outage management system (OMS), while a different team is evaluating and installing smart meters. The OMS team could choose an outage product that does not consider meter point information in the solution. The smart meter team could dismiss the need for meters that connect and report into an OMS. Each team could implement its solution and consider the projects successful – even quantifying the success by hitting target metrics.

Although each team missed the tremendous potential of an integrated system to understand outage scope, diagnose the cause of the outage and reroute power, they both could claim success. An electric utility organization policy that mandates holistic solution planning and evaluation would re-channel thinking and prevent these missed opportunities and overlooked synergies, so stimulus money invested would deliver maximum value.

The deployed smart grid is a new and evolving entity. Utilities, suppliers, engineers and regulators are fine-tuning solutions, implementing new ideas and benchmarking performance every day.

Early adopters will have the advantage of working closely with solution providers and have a hand in determining the ultimate design and functionality of the smart grid tools. If you are one of the influencers, addressing your particular challenges will become a priority. The smart grid will work even better for you because you will help design it.

For the smart grid to deliver on its full potential for positive change in how we move and deliver electricity, we must change how we work as organizations. Stimulus funds are making the need more urgent.

Instead of the evolutionary change our industry is accustomed to and comfortable with, stimulus opportunity is now. Companies that embrace the new reality and change how they do business will get the most for their stimulus buck. They will select and install holistic solutions that deliver value across the enterprise today and long after stimulus funding is exhausted.

COMMUNICATIONS FOR THE SMART GRID

Mark Adamiak - GE Digital Energy

As the smart grid drives into the main stream of the utility enterprise, it becomes incumbent on the industry to identify an architecture based on what is the smart grid, what are the communication pieces involved, and how do they fit together. The "pieces" are the existing communication standards. The choice of a standard, however, is not a random process. There is an engineering process for the selection of relevant standards and subsequent migration to an Architecture. Such a process was funded by the Electric Power Research Institute and the output of this process is the IntelliGrid architecture [1]. This paper examines the architecture process of identifying the system requirements and the subsequent process of linking the requirements with candidate standards. Finally, the standards already chosen by the NIST as Smart Grid standards are presented.

1. IntelliGrid Enterprise Activities

In all cases, an architecture must be based on the functions it is required to perform. In order to identify these functions, a mechanism known as a Use Case was employed. A use case starts with a narrative that describes a specific smart function in the environment of interest. Distillation of the use case identifies data items and their movement through the environment under study. In the energy environment, there are multiple areas of interest.

In order to facilitate categorization of use cases, the energy environment was broken down into 6 primary business functions, namely: Market Operations, Transmission Operations, Distribution Operations, Primary Generation, Distributed Energy Resources, and Customer Services. Over 400 potential use cases were identified and the most demanding of there were elaborated in additional detail to construct a complete high-level set of requirements for the communications infrastructure. The requirements were further categorized as follows:

- Communication configuration requirements, such as one-to-many, mobile, WAN, LAN, etc.
- Quality of service and performance requirements, such as availability, response timing, data accuracy, etc.
- Security requirements, such as authentication, access control, data integrity, confidentiality, non-repudiation, etc.
- Data management requirements, such as large databases, many databases particularly across organizational boundaries, frequent updates, etc.
- Constraints and concerns related to technologies, such as media bandwidth, address space, system compute constraints, legacy interface, etc.
- Network management requirements, such as health and diagnostics of infrastructure and equipment, remote configuration, monitoring and control, etc.

As an example in this paper, the Demand Response use case is reviewed. The IntelliGrid Architecture considered the Demand Response system as part of the Customer Services functional area. While it is clear that Demand Response functionality operates within this domain, it is important to note that Demand Response is not an isolated island of functionality.

The entire premise of the IntelliGrid Architecture is that each of these envisioned applications must interact with other domains and functional areas within the Energy industry. Interoperability between and among other Demand Response systems and other Energy industry applications can be seen as one of the key drivers behind the IntelliGrid Architecture.

Given that a communication channel will exist into the home, commercial, or industrial electrical grid, the IntelliGrid Architecture identified a number of applications that directly touch the Demand Response system.

The complete list can be found on the IntelliGrid Architecture website, but Customer Domain specific functions are listed here as follows[2]:

1. Automatic Meter Reading (AMR)
   - Sub-metering
   - Auto-pay / Pre-pay metering
   - Load monitoring
   - Outage detection and isolation
   - Sub-contracted metering
   - Remote connect/disconnect
   - Energy usage display
   - Demand profiles
   - Measurement of customer outage minutes/hours
2. Customer Trouble Call Management
3. Real-time Pricing (RTP)
   - Day ahead schedule
   - Available by-pass mode
   - Hour ahead emergency condition
   - Automatic in-home load curtailment
4. Load Management
   - Direct Load Control under emergency conditions
   - DER Watt/VAR dispatch
5. Building/Home Energy Management Services
   - Building management
   - Customer energy bidding
   - Building security
   - Load analysis
   - Customer remote access
   - Home insulation level analysis
   - Equipment monitoring (e.g. clogged air filters, failed water heater element, etc.)
   - Occupancy based heating and lighting controls
6. Electric Car as Generation Source
7. Weather
   - In-home weather forecasts
   - In-home lightning and severe weather alert
   - Lightning location report

In addition, the customer communications infrastructure will enable other IntelliGrid "cross domain" activities such as:

- Feeder Voltage Optimization
- Downed conductor detection
- Faulted feeder isolation / feeder re-deployment
- Distributed Energy control and isolation
- Distribution based VAR support to transmission
- Distribution SCADA
- Microgrid establishment / control

2. IntelliGrid Demand Response Environments

Each of the myriad interrelated functions defines its own set of detailed functional and non-functional requirements. An architecture is not, however, intended to simply fulfill a patchwork of requirements. The architecture is not simply the union of the lists of detailed requirements for each function. Functions often have conflicting requirements and a good architecture must be flexible enough to accommodate such incongruous anomalies. To realize this, the IntelliGrid Architecture invented what were called "Environments".

An IntelliGrid Architecture Environment is defined as an information environment, where the information exchanges of power system functions have essentially similar architectural requirements, including their configuration requirements, quality of service requirements, security requirements, and data management requirements. These Environments reflect the requirements of the information exchanges, not necessarily the location of the applications or databases (although these may affect the information exchanges and therefore the environment). Since functions can have multiple types of information exchanges, these functions often operate across multiple Environments.

The IntelliGrid Architecture defined twenty one Environments that completely describe the communication requirements for the information exchanges as shown in Figure 1[3]:

Demand Response and all of the ancillary services it provides, enables, or directly touches, operates in several of these environments. A brief synopsis of the relevant environments and typical applications shown in Figure 2[3]:

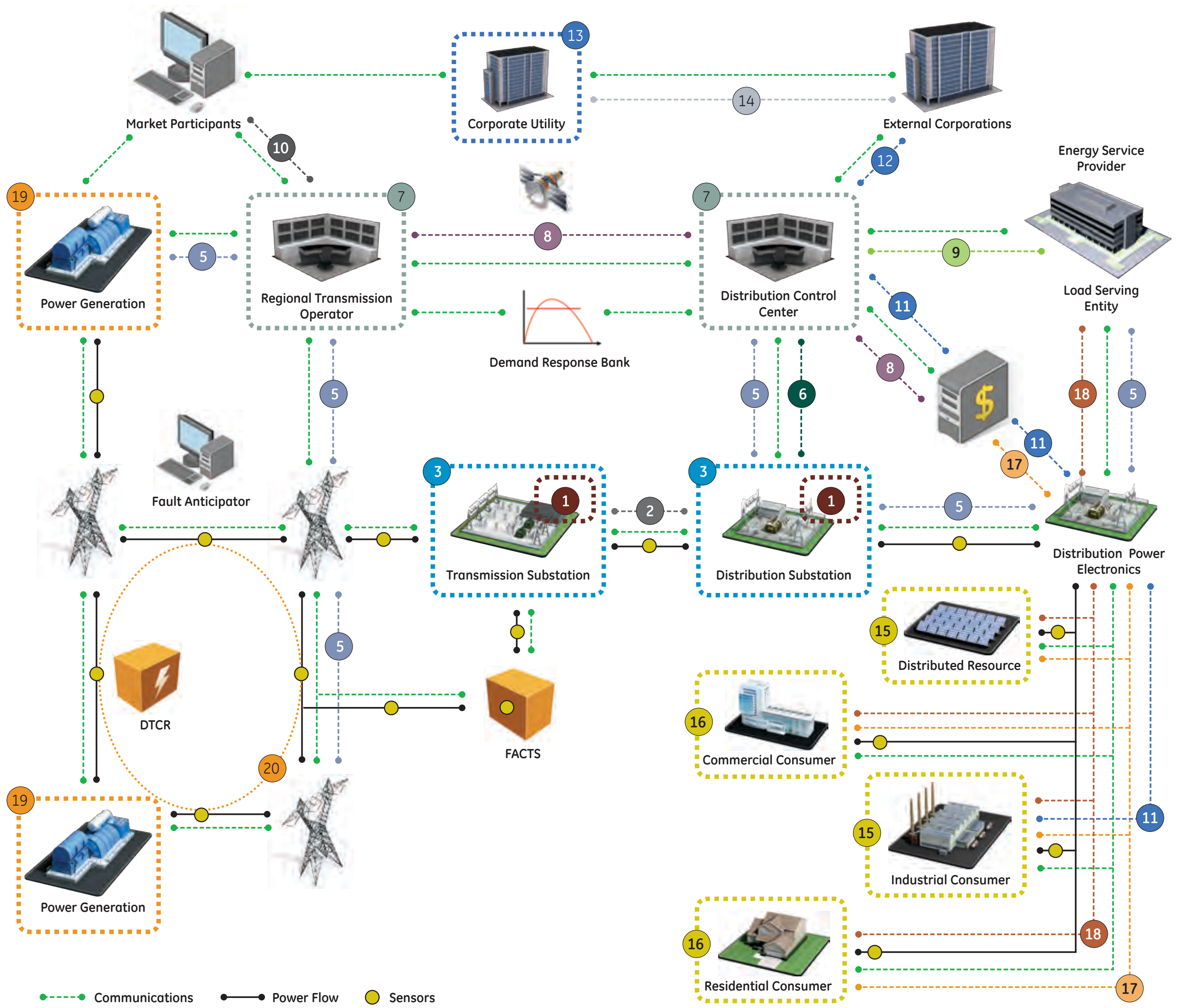
3. IntelliGrid Requirements for Demand Response Implementations

Based upon the above Environments, the IntelliGrid Architecture proposes a base set of high level requirements for Demand Response Systems that will also aid in achieving interoperability with other systems sharing the same infrastructure. These requirements are categorized as follows [3]:

Configuration Requirements

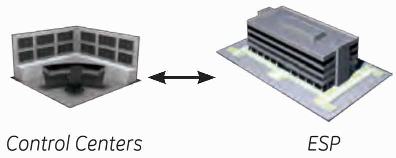
- Support interactions between a few "clients" and many "servers"
- Support peer to peer interactions
- Support interactions across widely distributed sites
- Support the frequent change of configuration and/or location of end devices or sites
- Support multi-cast or broadcast capabilities
- Support interactions within a contained environment (e.g. substation or control center)

IntelliGrid Architecture

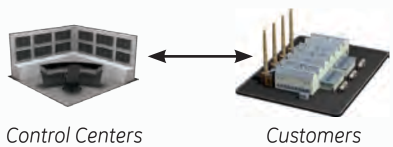


1	Deterministic Rapid Response Intra-Substation	8	Inter-Control Center	15	DER Monitoring and Control
2	Deterministic Rapid Response Inter-Site	9	Control Centers/ESPs	16	Intra-Customer Site
3	Critical Operations Intra-Substation	10	RTOs / Market Participants	17	Intra-Cusomer Sites
4	Inter-Field Equiment	11	Control Center / Customer Equipment	18	Customer / ESP
5	Critical Operations DAC	12	Control Center / Corporations	19	HV Generation Plant
6	Non-Critical Operations DAC:	13	Intra-Corporation	20	Field Equipment Maintenance
7	Intra-Control Center	14	Inter-Corporation	21	Special

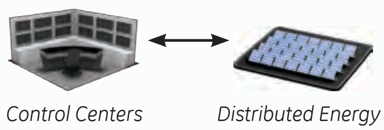
Figure 1.
The IntelliGrid Architecture defines 21 Environments that span the entire Electric Energy Enterprise



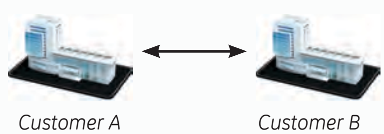
Environment 9: Control Centers to ESPs embodies the requirements for communications between utility control centers and Energy Service Providers or "aggregators". Typical applications in this environment include Real-time pricing negotiations, aggregated customer metering and settlements as well as data mining for later use in market operations. This is characterized as a business-to-business (B2B) environment having very strict requirements for security and a contractual level of timeliness and record keeping (and audit trails).



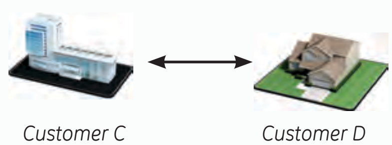
Environment 11: Control Center to Customers encompasses the requirements for what has traditionally been termed commercial or industrial metering and includes the requirements for any data exchange that goes directly between control centers and customer sites. Typical applications include metering of large customers, control of distributed energy resources, and load curtailment. This is characterized as a B2B environment but involving operational rather than financial data.



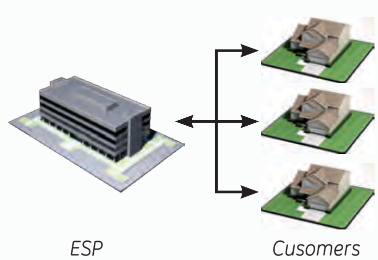
Environment 15: DER Monitoring and Control encompasses the communication requirements between distributed energy resources and the organizations that must monitor and operate them. Typical applications include an ESP aggregating data from or operating multiple small generators including renewable power, small hydro, co-generation or any other mini-grid. This may also include demand response and adjustment of power quality. This environment is characterized by the fact that it is vital that these message exchanges are not tampered with, monitored, or interfered with by unauthorized persons.



Environment 16: Intra-Customer Site defines requirements for communications that are local to customer sites (residential, commercial, or industrial). Typical applications include a customer printing processes online or offline in response to RTP, a customer locally managing a distributed energy resources in response to external factors (environment, price, regulations, etc.). Additionally this also includes building and home automation systems. This environment is characterized by critical data with local scope and limited impact on the overall power grid. Data is real-time potentially peer-to-peer with application specific security.



Environment 17: Inter-Customer Sites captures requirements for communications between customer sites (residential, commercial, or industrial). This is a relatively new environment that is not widely deployed yet but would include typical applications such as coordination of customer loads (e.g. A/C or refrigeration compressor startup) and mini-grid management. It is characterized by high security requirements because data crosses organizational boundaries.



Environment 18: Customer to ESP. This environment encompasses the communication, distributed processing, security, and data management requirements for applications that exist between ESPs, typically the distribution level energy utility, and the end-use point-of-sale energy customers like residential homeowners and apartment dwellers. Typical applications include automatic (or manual) meter reading, monitoring and control of DER, demand response and RTP. It is characterized by extremely large volumes of data with frequent con-figuration and topology changes to the communications network. Commands are often broad-cast due to the large number of end users but address space must be massively scalable.

Figure 2.
A brief synopsis of the relevant environments and typical applications

Quality of Service Requirements

- Provide medium speed messaging on the order of 10 seconds
- Support contractual timeliness (data must be available at a specific time or within a specific window of time)
- Support medium availability of information flows of 99.0+% (~3.5 days/year outage)

Security Requirements

- Provide Identity Establishment Service (you are who you say you are)
- Provide Authorization Service for Access Control (resolving a policy-based access control decision to ensure authorized entities have appropriate access rights and authorized access is not denied)
- Provide Information Integrity Service (data has not been subject to unauthorized changes or these unauthorized changes are detected)
- Provide Confidentiality Service (only authorized access to information, protection against eavesdropping)
- Provide Inter-Domain Security Service (support security requirements across organizational boundaries)
- Provide Non-repudiation Service (cannot deny that interaction took place)
- Provide Security Assurance Service (determine the level of security provided by another environment)
- Provide Audit Service (responsible for producing records, which track security relevant events)
- Provide Security Policy Service (concerned with the management of security policies)
- Provide Path and Routing Quality of Security (being able to determine a secure communication path)
- Provide Firewall Transversal
- Provide Privacy Service (the ability to ensure person information is not disclosed)
- Provide User Profile and User Management (combination of several other security services)
- Provide Security Protocol mapping (the ability to convert from one protocol to another)
- Provide Security Discovery (the ability to determine what security services are available for use)

Network and System Management Requirements

- Provide Network Management (management of media, transport, and communication nodes)
- Provide System Management (management of end devices and applications)
- Support extensive data validation procedures

Data Management Requirements

- Support the management of large volumes of data flows
- Support extensive data validation procedures
- Support keeping data consistent and synchronized across systems and/or databases
- Support timely access to data by multiple different users
- Support frequent changes in types of data exchanged
- Support management of data whose types can vary significantly in different implementations
- Support specific standardized or de facto object models of data
- Provide discovery service (discovering available services and their characteristics)
- Provide conversion and protocol mapping
- Support the management of data across organizational boundaries

4. IntelliGrid Design Principles [4]

In order to design an architecture, one must have "guiding principles" as to how to identify the pieces of the architecture and how they are to be put together. The IntelliGrid architecture identifies several such principles described below.

One of the most important system integration principles in IntelliGrid is the concept of Technology Independent Architecture (TIA). TIA is technology neutral or technology agnostic. It can insure successful integration of the various utility enterprise applications without requiring changes to the application's internal operation. It can also achieve high level of interoperability and interworkability with the built-in intelligence of auto-configuration and self discovery. Figure 3 illustrates the TIA framework.

Three key information-modeling elements in TIA framework are,

- Common Services – These are atomic building blocks frequently required by the utility applications. IntelliGrid further breaks the common services down to four categories, namely "system and network management services", "data management and exchange services", "common platform services" and "common security services".

- Common Information Models – These are common data that are exchanged between services and applications. This includes the suggested data format, data attributes and their relationships.

- Generic Interfaces – Generic Interfaces are used as the mechanism for exchanging Common Information Model data between services. Generic Interfaces correspond to how data is exchanged. It specifies a set of standard verbs such as “get”, “set”, “report”, which allows different applications to communicate with each other.

These common information-modeling elements are the key to achieving higher-level interoperability of power system distributed information systems.

Common Services

Common Services are commonly defined functionality derived by identifying the crosscutting distributed information requirements. Common Services allow components to be treated as black boxes. This facilitates greater flexibility, as components are less dependent on how each works internally.

However, the use of Common Services does not by itself substantially reduce the complexity of dealing with different platforms such as Java, .Net or Web Services. Also, Common Services do not necessarily deal with the discontinuity of the meaning of data. Lastly, Common Services do not deal with the discontinuity caused by different data access mechanisms such as “read/write data” or “subscribe to data”.

To overcome semantic heterogeneity a common information model is used as the common language that all services use to communicate. To overcome platform heterogeneity, the generic interface is required. The generic interface can be implemented on any platform. While the different implementations of the generic interface are not interoperable, “off the shelf”, the mapping from one platform specific implementation to another is simple and well known.

Common Information Models

In order to precisely describe the meaning of a set of terms, engineers often create an information model. An information model describes a collection of related real world objects. An information model describes objects in terms of classes, attributes and relationships and provides unique names and definitions to each object.

The EPRI/IEC Common Information Model (CIM) describes data typically used in the power system. The CIM contains object types such as substations, breakers, and work orders as well as other data typically found in an EMS, SCADA, DMS, or work, and asset management system. More recently, the CIM is being extended to include transmission reservation and energy scheduling information. In general, the benefit of creating an information model include:

- Models give context to data improving understanding and productivity.

- Models enable automation of setup and maintenance tasks.

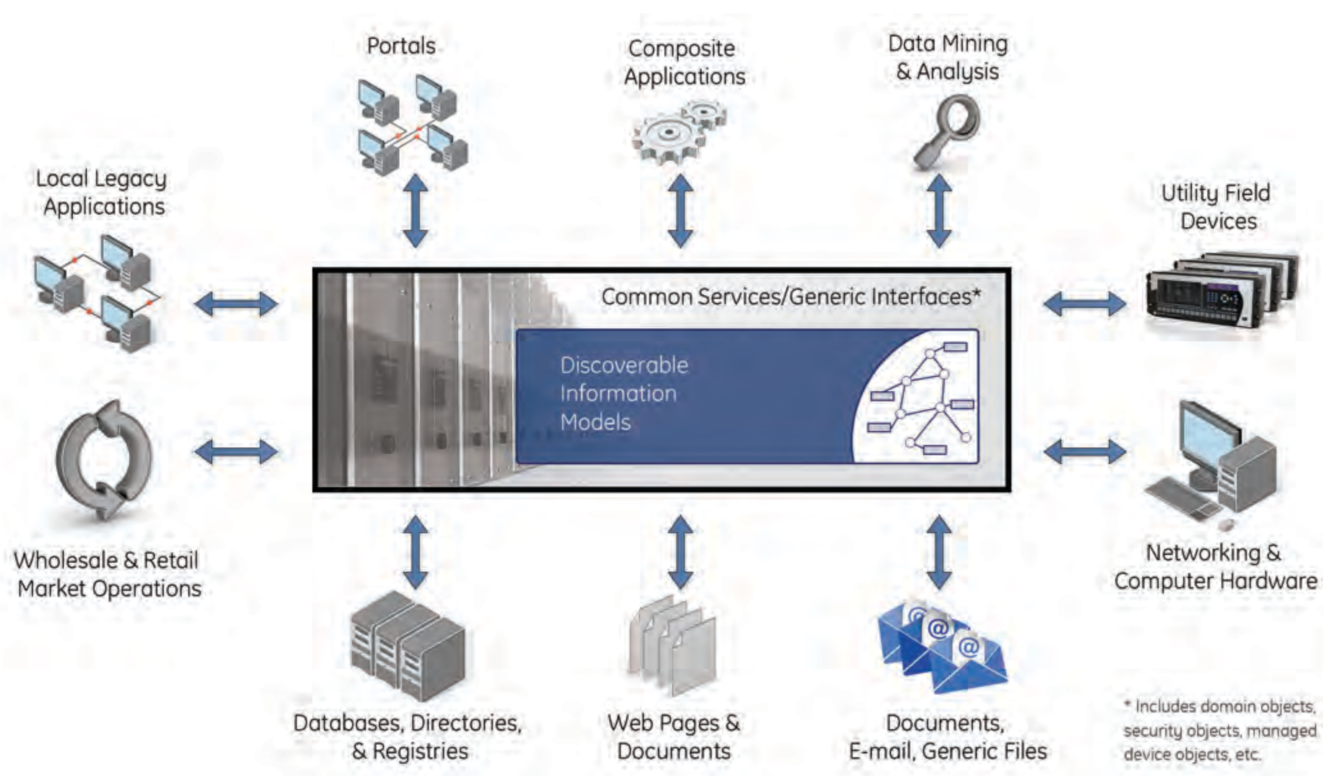


Figure 3.
Technology Independent Architecture - The guiding principle of the IntelliGrid Architecture shows that Common Services, Common Information Models, and Generic Interfaces enable scalable interoperability in a heterogeneous technology environment.

Generic Interfaces

The mechanism used to exchange data is determined by an application's interface. However, the native interface provided by an application is typically limited. For example, typically existing interfaces:

- Do not expose data within the context of a common inter-application data model.
- Do not provide a means to discover what business object instances are serviced by a particular component instance other than a rudimentary listing of legacy IDs (tags) that cannot be viewed within the context of an inter-application data model such as a power system network model.

Without a means to discover what data an application processes, plug and play is nearly impossible to achieve. To address these impediments to plug and play and the need for a common exchange mechanism, "Generic Interface" is introduced to specify how data are exchanged. The phrase "Generic Interface" is an umbrella term for four interfaces types:

- An interface for mapping names to ID's and visa versa.
- A request/reply oriented interface that supports browsing and querying randomly associated structured data – including schema (class) and instance information.
- A publish/subscribe oriented interface that supports hierarchical browsing of schema and instance information. This interface would typically be used as an API for publishing/subscribing to XML formatted messages.
- Applications use the generic interfaces to connect to each other directly or to an integration framework such as a message bus or data warehouse. A technology neutral interface allows applications to be designed independently of the capabilities of the underlying infrastructure.

Generic interfaces provide the following key functionality required for creation of a plug and play infrastructure:

- Interfaces are generic and are independent of any application category and integration technology. This facilitates reusability of applications supporting these interfaces.
- Interfaces support schema announcement/discovery – The schemas are discoverable so that component configuration can be done programmatically at run time. Programmatically exposing the schema of application data eliminates a great deal of manual configuration.
- Interfaces support business object namespace presentation – Each component describes the business object instances that it supports within the context of a common namespace shared among all applications such as a power system network model like the EPRI Common Information Model (CIM). It is not enough to merely expose the application data schema, one must also expose what specific breakers, transformers, etc., that an application operates on. This also eliminates manual configuration as well as provides a means for a power system engineer to understand how enterprise data is organized and accessed.

REMEMBER THAT DEVELOPING AN INDUSTRY-LEVEL ARCHITECTURE IS A PROCESS – NOT AN END POINT

5. IntelliGrid Recommended Implementation Technologies

There are too many recommendations to capture in this project summary, but common themes can be identified as follows[1]:

- Harmonize the existing common services, information models, and interfaces, as well as create new standards where they are needed, so the power industry speaks a common communications language of 'nouns' and 'verbs' that can be translated into different technologies. This is a key requirement for the higher levels of system integration now emerging across the energy industry
- Integrate security, systems, network management, and technical development (i.e. new technologies), which have too often been considered separate tasks.
- Unify technologies between power system automation networks, corporate networks, and inter-business networks, again by linking them to common information models, services, and interfaces.
- Remember that developing an industry-level architecture is a process – not an end point. Requirements and enabling technologies are constantly changing. Although the guiding principles should remain constant, individual solutions will change over time.

Based on the identified design principles, IntelliGrid makes a link from design guidelines to recommended technologies that best embody the stated principles and meet the identified requirements. IntelliGrid makes a point of recognizing that many needed technologies may not exist and encourages the identification and subsequent standardization of such technologies.

The list below is a first level summary of the "primary" recommended technologies for the identified environments. The list is organized by functional layer. For the complete list of applicable technologies, please refer to the IntelliGrid.info website[3]:

Data Exchange:

- IEC61850 – Communication Networks and Systems in Substations

  - Data Models

  - Abstract Services

  - Substation Configuration Language
- ANSI C12.19 Metering Tables

- AEIC Guidelines for Implementation of ANSI C12.19
- IEC61970 Part 3 Common Information Model (CIM)
- IEC61970 Part 4 Generic Interface Definition
- IEC61968 SIDM System Interfaces for Distribution Management
- IEC60870-6 Inter Control Center Protocol
- IEC62325 on Framework for Energy Market Communications
- NERC e-tagging
- NAESB OASIS for Market Transactions
- IEC62056 – Data Exchange for Meter Reading, Tariff, and Load Control
- Universal Description, Discovery, and Integration (UDDI)
- Simple Object Access Protocol (SOAP)
- EbXML
- XML Metadata Interchange (XMI)
- Meta Object Facility (MOF)
- Globally Unique Identifiers (GUID)
- S/NTP (Simple/Network Time Protocol)
- ANSI/ISO/IEC 9075 – Structured Query Language (SQL)

Security:

- ISO/IEC 10164-8:1993 Security Audit Trail Function - Information technology - Open Systems Interconnection - Systems Management - Security,
- ISO/IEC 18014-1:2002 Time-Stamping Services - Information technology - Security Techniques - Part 1: Framework - Security, Data Management
- ISO/IEC 10181-7:1996 Security Audit and Alarms Framework - Information technology - Open Systems Interconnection -- Security Frameworks for Open Systems - Security,
- FIPS PUB 112 Password Usage - Security,
- FIPS PUB 113 Computer Data Authentication - Security,
- RFC 1510 The Kerberos Network Authentication Service (v5)
- RFC 2196 Site Security Handbook - Security,
- RFC 2401 Security Architecture for the Internet Protocol - Security,
- RFC 2527 Internet X.509 Public Key Infrastructure Certificate Policy and Certification Practices Framework - Security,

THERE ARE MANY LONG-TERM BENEFITS TO THE ENERGY INDUSTRY THAT WILL BE REALIZED THROUGH IMPLEMENTATION OF THE INTELLIGRID PRINCIPLES AND RECOMMENDED TECHNOLOGIES

Transport:

- TCP / Internet Protocol IPV4 / IPV6

Network Management:

- Simple Network Management Protocol (SNMP)

Physical/Data Link:

- IEEE 802.x (LAN, WAN, WiFi, WiMax, Ethernet)
- SONET
- ATM

6. NIST Selected Smart Grid Standards – Rev 1.0

As part of the Energy Independence and Security Act of 2007, the North American Institute of Standards and Technology (NIST) was mandated by Congress to coordinate a “framework of protocols and model standards to achieve interoperability of the Smart Grid”. As part of this mandate, NIST has recently released the first set of “accepted” standards for use in Smart Grid communications [5].

It is to be noted that this is a work in progress and is not exclusionary. The list of these standards follows closely to the recommendations made by the IntelliGrid document. The list of selected standards is as follows:

- AMI-SEC System Security Requirements
- ANSI C12.19/MC1219 – Revenue Metering
- BACnet ANSI ASHRAE 135-2008/ISO 16484-5 – Building Automation
- DNP3 - Substation and feeder device automation
- IEC 60870-6 / TASE.2 - Inter-control center communications
- IEC 61850 - Utility automation and protection
- IEC 61968/61970 - Application level energy management system interfaces
- IEC 62351 Parts 1-8 - Information security for power system control operations
- IEEE C37.118 - Phasor measurement unit (PMU) communications
- IEEE 1547 - Physical and electrical interconnections between utility and distributed generation (DG)
- IEEE 1686-2007 - Security for intelligent electronic devices (IEDs)
- NERC CIP 002-009 - Cyber security standards for the bulk power system

- NIST Special Publication (SP) 800-53, NIST SP 800-82 - Cyber security standards and guidelines for federal information systems, including those for the bulk power system

- Open Automated Demand Response (Open ADR) - Price responsive and direct load control

- OpenHAN - Home Area Network device communication, measurement, and control

- ZigBee/HomePlug Smart Energy Profile - Home Area Network (HAN) Device Communications and Information Model

This list will continue to grow as new standards are identified and as new standards are developed to meet the identified gaps in the existing standards.

7. Conclusion

The IntelliGrid Architecture provides a foundation for the operation of the Smart Grid and offers an optimized approach to build future visions. There are many long-term benefits to the energy industry that will be realized through implementation of the IntelliGrid principles and recommended technologies.

Clearly the IntelliGrid Architecture has profound ramifications for a broad range of advanced power systems applications. Careful planning of an open and standards-based system design will support integration of advanced systems thus realizing the IntelliGrid vision for the Smart Grid of the future.

8. References

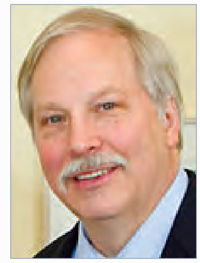
[1] Peter Sanza, Joe Hughes, et. al.; "IntelliGrid Architecture Volume I 'User Guidelines and Recommendations' Final Report", 2004, Electricity Innovation Institute (E2I) Consortium for Electric Infrastructure to Support a Digital Society (CEIDS); www.IntelliGrid.info.

[2] Peter Sanza, Joe Hughes, et. al.; "IntelliGrid Architecture Volume II Appendix F 'Task 1 Enterprise Activities' Final Report", 2004, Electricity Innovation Institute (E2I) Consortium for Electric Infrastructure to Support a Digital Society (CEIDS); www.IntelliGrid.info.

[3] Peter Sanza, Joe Hughes, et. al.; "IntelliGrid Architecture Volume IV Appendix E 'Environments' Final Report", 2004, Electricity Innovation Institute (E2I) Consortium for Electric Infrastructure to Support a Digital Society (CEIDS); www.IntelliGrid.info.

[4] Peter Sanza, Joe Hughes, et. al.; "IntelliGrid Architecture Volume IV 'Technical Analysis' Final Report", 2004, Electricity Innovation Institute (E2I) Consortium for Electric Infrastructure to Support a Digital Society (CEIDS); www.IntelliGrid.info.

[5] NIST Recognized Standards for inclusion in the Smart Grid Interoperability Standards Framework – Release 1.0; www.nist.gov/smartgrid/standards.html



Mark Adamiak

Mark Adamiak is the Director of Advanced Technologies for GE Digital Energy and is responsible for identifying and developing new technology for GE's protection and control business. Mark received his Bachelor of Science and Master of Engineering degrees from Cornell University in Electrical Engineering and an MS-EE degree from the Polytechnic Institute of New York. Mark started his career with American Electric Power (AEP) in the System Protection and Control section where his assignments included R&D in Digital Protection and Control, relay and fault analysis, and system responsibility for Power Line Carrier and Fault Recorders. In 1990, Mark joined General Electric where his activities have ranged from advanced development, product planning, application engineering, and system integration. Mr. Adamiak has been involved in the development of both the UCA and IEC61850 communication protocols, the latter of which has been selected as a NIST Smart Grid protocol. Mark is a Fellow of the IEEE, a member of HKN, past Chairman of the IEEE Relay Communication Sub Committee, a member of the US team on IEC TC57 - Working Group 10 on Utility Communication, the US Regular Member for the CIGRE Protection & Control study committee, a registered Professional Engineer in the State of Ohio and a GE Edison award winner for 2008.

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Application of Digital Radio for Distribution Pilot Protection and Other Applications

Rich Hunt, Steel McCreery, Mark Adamiak Al King
GE Digital Energy

Networked distribution lines, sub-transmission lines, and industrial facility incoming supply lines have always presented an interesting protection challenge. As the number of distributed generators and cogeneration facilities increase, directional overcurrent protection and distance protection may not be selective enough for reliable protection without the implementation of pilot protection schemes such as permissive over-reaching transfer trip and directional comparison blocking.

Pilot-wire relaying has been the traditional solution at distribution voltages. Pilot-wire relaying sends a voltage signal between relays at each end of the line across copper wire. These voltages are used for differential protection. This scheme was used because of availability of copper pairs from the phone company and/or the low cost of installation of the communications wire. Today, however, copper pairs are no longer available from the phone company and the cost of installing new copper is increasingly expensive. When fiber access is available (typically at a premium cost), communication based digital protection solutions such as current differential relays and directional overcurrent relays in a pilot protection scheme are used.

The modern challenge is a method to provide digital communications for pilot protection that is reliable and affordable. Digital radio is an inexpensive method to provide digital communications for pilot protection at the distribution level. Digital radio has the ability to send permissive, blocking, and transfer trip signals over short to medium distances. Relay to relay messaging protocols have now become standardized through the IEC 61850 GOOSE profile and can provide not only protection information but also metering, monitoring, and control.

Practical concerns for the protection engineer include the reliability, security, and latency of digital radio communications, as this has a strong influence on selecting and setting the protection scheme. To address these concerns, this paper presents actual field data for radio signal reliability and latency. Based on this actual data, some recommendations for pilot protection schemes at the distribution level are presented. In addition, the paper also reviews the application requirements for digital radio, including design for redundancy, path concerns, antenna selection and site evaluation, and use of licensed and spread spectrum radios. Since modern digital radio also support higher communications bandwidth, the paper will explore some other innovative applications that can operate in concert with pilot protection communications.

1. Introduction

This paper considers the application of pilot protection on distribution lines. Pilot protection uses communications channels to send information between relays at each end, and is commonly used on networked lines. For the purpose of this paper we can assume distribution lines are circuits with an operating voltage typically between 4 KV and 69 KV. However, the principles discussed in this paper can be applied to any circuit at any voltage level, assuming the protection requirements for speed, security, and dependability can be met.

The protection challenges for pilot protection of distribution lines are identical to the protection challenges for pilot protection on transmission lines. The major goal for pilot protection is to operate dependably for a fault on the protected line and securely for faults outside the protected line (Figure 1). One challenge unique to distribution is that the protected line may change from a networked line to radial line quite frequently. If the line is from a utility source serving a load with generation capabilities, the line is only networked while the generation is running.

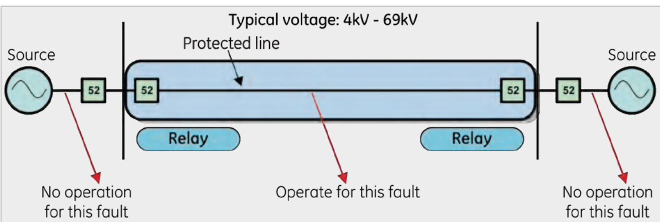

Figure 1.
Pilot protection challenge

2. Typical applications

The majority of distribution systems are radial systems, which allows the application of time-coordinated overcurrent protection schemes. While the overall distribution system may be designed as a radial system, individual pieces may be effectively networked. Short distribution lines to industrial facilities with significant generating capabilities, or short lines to independent power producers, may result in a small networked system. In addition, some parts of the distribution system are intentionally networked, such as in large urban load centers. In these cases, protection system must use a secure method of identifying faults to ensure appropriate isolation of faulted sections of the system. In any of these cases, some form of pilot protection is typically applied.

3.1 Industrial facility with fault current source

As mentioned above, one common example of an effectively networked radial distribution system is the short distribution line that connects an industrial facility with some generation to a utility distribution network. The local generation in the industrial facility may or may not be large enough to carry the complete facility load, but the generation is a source for short-circuit current on the incoming distribution line and the utility system. A less common example is an industrial facility with two different distribution feeds operating in parallel, where the second utility feed can provide short circuit current to the first utility feed. In either case, this application typically requires the use of some sort of directional protection, or protection that can identify the fault is on the incoming distribution line. There is only fault current contribution from the industrial facility when the local generation is running. The protection scheme must still operate correctly when the generation is not running and there is no contribution from the plant.

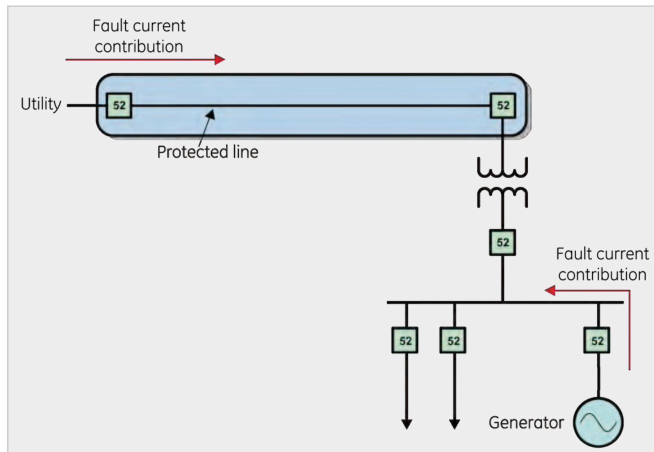

Figure 2.
Brick - rugged outdoor merging unit

3. Protection solutions

There are a variety of protection schemes for short, networked distribution lines. These schemes can be grouped as those requiring no communications between line terminals, and as pilot protection that requires communications between line terminals. The protection schemes that don't require communications use some form of directional protection, either directional overcurrent relays or distance protection. Just as with transmission line

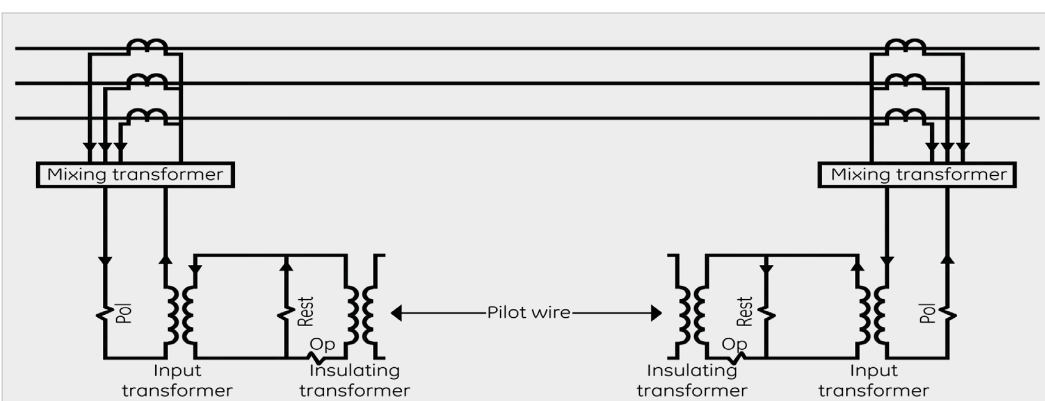

Figure 3.
Pilot-wire protection scheme

applications, directional protection is rarely applied on distribution systems without pilot communications in order to address concerns about coordination, security, and operating time.

Pilot protection schemes use some form of communications between relays at both line ends to ensure secure, selective tripping. The communications medium used depends on the type protection selected, the capabilities of the relay selected, and other factors such as cost of installation. Pilot protection methods may send analog values between relays at each end of the line, or they may use simple on/off, permissive, or blocking signals between relays at each end of a line.

3.1 Pilot-wire protection

One protection scheme that needs some emphasis is pilot-wire protection. Pilot-wire relays create a voltage signal to represent the measured current at the relay location. The pilot-wire relay then sends this voltage via telephone-type copper cable to the relay at the other end of the line. Pilot-wire relays use the voltages at each end in voltage differential protection. Pilot-wire relaying therefore requires only current measurements, is directionally secure, and is very simple to implement and set. Pilot-wire protection was the best solution from analog, electro-mechanical designs. For these reasons, pilot-wire protection has been the traditional solution for protection of short, networked distribution lines serving industrial facilities.

However, the industry is moving away from pilot-wire relaying as a solution for the protection of short, networked distribution lines. This move has little to do with the performance of pilot-wire relaying, but has more to do with the general trend towards digital relays and the use of digital communications. Once digital communications are used, current differential is a better protection choice. Digital representation of analog currents can be sent between each end, on a per-phase basis.

3.2 Other common protection methods

Other common protection methods for the short, networked distribution line include line differential relaying and pilot protection schemes such as permissive overreaching transfer trip (POTT) schemes and directional comparison blocking (DCB) schemes. All of these methods require communications between the relays at each end of the line. Line differential relaying generally requires a fiber-optic or other reliable communication channel. Pilot protection schemes require a communications channel that can transmit a binary, on/off, permissive or blocking signal. This channel can be a tone sent over an analog telephone line, power line carrier system, tone over microwave, or fiber-optic cable.

But the key piece of all of these protection methods, and a great challenge to reliability, is the communications channel. The communication channel must meet application requirements for performance, reliability, and cost. Performance requirements are clear: the communications channel must be physically capable of sending the correct type of pilot signal, have enough bandwidth to handle the signal, and have a short enough system latency time.

Reliability requires that the communications channel always be available. The channel consists of the actual media used, and any interface or conversion devices required between the relay and the communications channel. This is one of the reasons for the popularity of pilot-wire relaying. The connection between relays for pilot-wire relaying is a physical wiring connection, with no other devices to fail.

Cost of equipment, cost of installation, and cost of maintenance are all important considerations. For a new facility or expansion project, the cost of installing fiber-optic cable is only an incremental cost. However, as pilot-wire systems age, and the copper pilot wire degrades and fails, the cost of installation is a larger concern. Installing fiber-optic cable, or even copper cable, in a retrofit installation, is very expensive. The equipment costs may wind up as a trivial part of the total project cost.

Protection Method	Data Type	Message Size	Latency Time	Communications Media
Pilot-wire relaying	Analog (voltage)	-	< 1 ms	Metallic pilot-wire pair
Line differential relaying	Analog converted to digital message	Large	8 ms	Fiber-optic
Pilot protection (POTT, DCB)	Boolean (blocking signal, permissive signal)	Small	8-16 ms	Analog telephone line Microwave power line Carrier fiber-optic

Table 1.
Communications channel requirements

4. Digital Radio

The age of modern industrial radio data communications was ushered in when it was proven that digital data could be economically and reliably transmitted from one device to another using a voice radio set, known as narrow band radio, fitted with a modem. Packet radio is a term coined by amateur radio enthusiasts that refers to this type of digital radio communications equipment. Modern digital radios trace their design heritage back to the days of the first packet radios. Over the years technological advancements in the area of digital radio communications have led to a wide range of radio equipment for applications ranging from simple voice communications to the simultaneous transmission of multiple high-speed data channels over a wide band radio link.

The attraction of digital radio for protection of short distribution lines is installed cost, particularly in retrofit situations. For short lines (less than 1 mile in length) with good line of sight between line ends, the total equipment costs can be less than $5,000. The installation involves only a small project of around 16 to 24 man-hours for design and installation time. The concern over digital radios is performance. Performance of other communication medium and protection applications is well known and well understood by protection engineers. But digital radio is still new to the protection area. So the questions of performance related to data types, bandwidth, channel latency, distance, and reliability must be understood.

4.1 Data types

Currently at the physical layer digital radios apply two common interface standards: RS485 and 10BaseT Ethernet. The choice of interface directly impacts the transmission range and type of radio.

Interface	Protocol	Bandwidth	Type of Radio	Typical Maximum Distances
10BaseT	DNP3 via TCP/IP, ModBus, IEC 61850	0.5 MB	Spread spectrum: No License required	Up to approximately 20 miles (terrain permitting)
10BaseT	DNP3 via TCP/IP, ModBus, IEC6 1850	1.0 MB	Spread spectrum: No License required	Up to approximately 15 miles (terrain permitting)

Table 2.
Digital radio application guidelines

4.2 Terminology

Before proceeding further it is best to define some common terms that will be used through the rest of this application note.

Spread Spectrum Radios: Radio transmission using the spread spectrum technique was originally developed to provide jam-resistant military communications. Spread spectrum uses a modulation technique that distributes a transmitter's signal over a very wide bandwidth, making it virtually undetectable to a conventional radio receiver. Frequency Hopping spread spectrum and Direct Sequence spread spectrum are the two primarily methodologies spread spectrum technology uses to transmit messages today. Frequency Hopping spread spectrum radios are better in environments with interference, and are less likely to be jammed. Direct Sequence spread spectrum radios can support higher data bandwidths.

Narrow Band Radios: In communications, narrowband is a relative term. From one perspective these voice channel radios are the modern equivalent of the old packet radios. With baud rates of up to 9.6k they are typically used in SCADA applications supporting a single protocol such as DNP or ModBus. They are typically licensed with up to a 50 mile range.

Wide band: In communications, wideband is again a relative term. This term typically applies to radios that have a bandwidth of 200 KHz allowing multiple channels of data to be transmitted at the same time.

Access Point Radio: The radio that connects the remote radios together to form a wireless network. The wireless access point (WAP) usually connects to a wired network, and can relay data between the remote radios and devices on its wired network.

4.3 Digital radio performance testing

The best way to prove digital radio performance for pilot protection is to test performance under field conditions. The test in this case was for channel latency and channel reliability. The protection message between each relay is an IEC 61850 GOOSE message.

4.4 Application: Pilot protection via IEC 61850 GOOSE and spread spectrum radios

The radios were connected in a point-to-point topology, exactly as the typical pilot protection application. The test protocol was a simple matter of measuring the round trip time of each automatically generated IEC 61850 GOOSE messages transmitted from one relay to another relay and then immediately echoed back to the first relay.

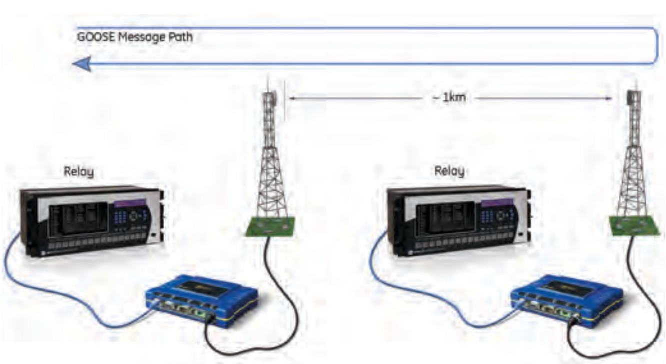

Figure 4.
Digital radio pilot protection test setup

This paper defines channel latency as the delay between the initiation of the GOOSE message by the sending relay and the reception of the GOOSE message by the receiving relay. The test actually measures the round-trip channel latency, as one relay measures the time between sending the original message and receiving the echoed response. Of interest for pilot protection applications is the one-way channel latency, which is assumed to be one half of this directly measured round-trip channel latency.

4.5 Performance

The test was actually a time-based test. The IEC 61850 GOOSE messages were sent back and forth for some length of time. At the end of the test, 29,672 messages were sent. The test results from the 29,672 consecutive messages are recorded in Table 3.

Round Trip Time	No. of Messages	Percentage
< 20 ms	232	0.78 %
20-30 ms	29.303	98.76 %
30-40 ms	127	0.43 %
40-80 ms	10	0.03 %

Table 3.
Radio performance test results

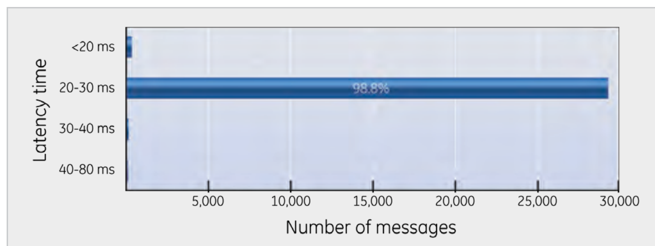

Figure 5.
Digital radio pilot protection test setup

The typical round-trip time is 20 to 30 ms, meaning the channel latency is 10 to 15 ms. This is very acceptable performance for pilot protection on distribution systems. Therefore digital radio meets general performance requirements for pilot protection applications.

4.6 Site installation and commissioning procedures

The key issue with any communications channel used for protection is the reliability of the channel, in this case specifically the reliability of the radio path. The important factors for digital radio are the distance between transmitter and receiver, obstructions in the line of sight between antennas, and the natural environment beneath the path.

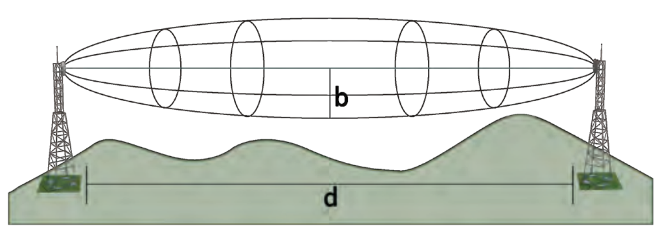

Figure 6.
Fresnel Zone

Radio communications is limited to "line of sight". However, radio line of sight is longer than the optical line of sight due to the bending of the radio wave towards the surface of the earth. This radio horizon is typically 30% longer than the visual horizon. Therefore, a longer communications path requires taller antennas to maintain the line of sight.

DIGITAL RADIO IS AN INEXPENSIVE METHOD TO PROVIDE DIGITAL COMMUNICATIONS FOR PILOT PROTECTION AT THE DISTRIBUTION LEVEL

Obviously, obstructions in the line of sight will impact the performance of the digital radio, as the strongest radio signal is communicated directly along the radio line of sight. As obstructions block the width of the radio wave front, less of the signal gets through to the antennas. Obstructions may also cause multi-path interference due to reflective or refractive signals that may arrive at the receiver out of phase with the desired signal. However, due to the diffraction of the radio wave, objects not directly in the line of sight can also act as obstructions. The region where obstructions may impact the performance of the radio wave is known as the Fresnel zone.

A Fresnel zone (Figure 6) is one of a (theoretically infinite) number of concentric ellipsoids of revolution that define volumes in the radiation pattern of the radio wave. There are multiple Fresnel zones, but only the first Fresnel zone is important for signal strength.

In practice, 60% of the first Fresnel zone must be clear of obstructions to allow successful radio communications. The radius of the Fresnel zone at its widest point (at the center of the radio line of sight) can be determined by:

$$b = 17.32\sqrt{\frac{d}{4f}}$$

Where b = radius of the Fresnel zone
d = distance between transmitter and receiver
f = frequency transmitted in GHZ

Beyond line of sight requirements and Fresnel zone requirements, the other concern with a digital radio path is fading, or the probability that the radio signal will be lost due to other conditions. The fade margin determines the allowable signal loss between the transmitter and receiver. The fade margin is a function of system gains (transmitter power, receiver sensitivity, and antenna gain) and system losses (free space loss, losses due to earth curvature, coaxial cable loss). Variations in the temperature and humidity of the atmosphere with elevation causes the signals to bend more or bend less, resulting in fading at the receiver. The longer the path, the more likely deep fades will occur, requiring a greater fade margin. The local propagation conditions impact the probability of signal fade as well. Generally, mountainous terrain is favorable, and tropical areas and those near large bodies of water are unfavorable.

One of the losses considered when determining the fade margin is free space loss. Free space loss is the loss in signal strength of the radio wave passing through free space. Free space loss is the basic path loss of the system. Free space loss is defined by:

$$\text{Free Space Loss} = 92.4 + 20\log(f) + 20\log(d)\ \text{dB}$$

Where f = frequency in GHz
d = distance in km

Like any other communications channel, proper installation results in desirable performance. The installation of digital radio systems requires proper site selection, an evaluation of path quality, and correct selection and mounting of antennas. The following is a brief overview of these requirements.

Evaluating Path Quality

For optimum radio performance, the installation sites for master and remote stations must be carefully considered. Suitable sites should provide:

- Protection of the radio equipment from direct weather exposure
- A source of adequate and stable primary power
- Suitable entrances for antenna
- Interface or other required cabling
- Antenna location that provides an unobstructed transmission path in the direction of the associated station(s).

Evaluating Path Quality

A line-of-sight path is ideal and provides the most reliable transmission in all cases. However, minor obstructions in the signal path will not necessarily block communication but will result in signal attenuation. In general, the need for a clear path becomes greater as operating frequency and transmission distance increases. Short-range paths (less than 1 mile) can be visually evaluated. Longer distances typically require a path study for new installations. A path study predicts the signal strength, reliability and fade margin of a proposed radio link. While terrain, elevation and distance are the major factors in this process, a path study must also consider antenna gain, feedline loss, transmitter power, and receiver sensitivity to arrive at a final prediction.

Antenna Selection and orientation

The single most important item affecting radio performance is the antenna system. Careful attention must be given to this part of an installation, or the performance of the entire system will be compromised. High quality, high gain antennas should be used at all master and remote stations. The antennas should be specifically designed for use at the intended frequency of operation.

Communication antennas are made by a number of manufacturers and fall into two general categories, omni-directional, and directional. An omni-directional antenna provides equal radiation and response in all directions and is therefore appropriate for use at master stations, which must communicate with an array of remote stations scattered in various directions. At remote stations, a directional antenna such as a yagi is typically used. Directional antennas confine the transmission and reception of signals to a relatively narrow lobe, allowing greater communication range, and reducing the chances of interference to and from other users outside the pattern. It is necessary to aim these antennas in the desired direction of communication. The end of the antenna (furthest from the support mast) should face the associated station. Final alignment of the antenna heading can be accomplished by orienting it for maximum received signal strength. Most radio equipment includes provisions for measuring signal strength.

Antenna Mounting Considerations

The antenna manufacturer's installation instructions must be strictly followed for proper operation of a directional or omni-directional antenna. Using the proper mounting hardware and bracket ensures a secure mounting arrangement with no pattern distortion or de-tuning of the antenna. The following recommendations apply to all antenna installations:

- Mount the antenna in the clear, as far away as possible from obstructions such as buildings, metal objects, dense foliage, etc. Choose a location that provides a clear path in the direction of the associated station.
- Polarization of the antenna is important. Most systems use a vertically polarized omni-directional antenna at the master station. Therefore, the remote antennas must also be vertically polarized (elements perpendicular to the horizon). Cross-polarization between stations can cause a signal loss of 20 decibels (dB) or more.

Figure 7.
Omni-directional antenna

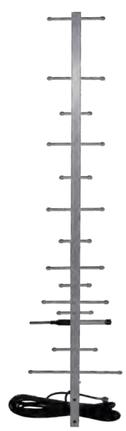

Figure 8.
Yagi antenna

The omni-directional antenna (Figure 7) is a typical antenna that used at an access point. The above Yagi antenna (Figure 8) is a typical antenna that would be use at a field station. Note the polarization this antenna is correct if used with either of the above omni-directional antennas.

Feedlines

The choice of feedline used with the antenna should be carefully considered.

Cable type	10 feet	50 feet	100 feet	500 feet
RG-214	0.76 dB	3.8 dB	7.6 dB	Unacceptable Loss
LMR-400	0.39 dB	1.95 dB	3.90 dB	Unacceptable loss
½ inch HELIAX	0.23 dB	1.15 dB	2.29 dB	11.45 dB
7/8 inch HELIAX	0.13 dB	0.64 dB	1.28 dB	6.40 dB
1-1/4 inch HELIAX	0.10 dB	0.48 dB	0.95 dB	4.75 dB
1-5/8 inch HELIAX	0.08 dB	0.40 dB	0.80 dB	4.00 dB

Table 4.
Feedline signal loss

Poor-quality coaxial cables should be avoided, as they will degrade system performance for both transmission and reception. The cable should be kept as short as possible to minimize signal loss. For cable runs of less than 20 feet (6 meters), or for short range transmission, an inexpensive type such as Type RG-8A/U may be acceptable. Otherwise, use a low-loss cable type suited for 900 MHz, such as Heliax®.

Setting the output power

The maximum transmitter output power allowed under FCC rules is +30 dBm. The power must be decreased from this level if the antenna system gain exceeds 6 dBi. The allowable level is dependent on the antenna gain, feedline loss, and the transmitter output power setting.

NOTE: In some countries, the maximum allowable transmitter output may be limited to less than the figures referenced here. Be sure to check for and comply with local requirements.

Example:

To determine the maximum allowable power setting of the radio, perform the following steps:

1. Determine the antenna system gain by subtracting the feedline loss (in dB) from the antenna gain (in dBi). For example, if the antenna gain is 9.5 dBi, and the feedline loss is 1.5 dB, the antenna system gain would be 8 dB. (If the antenna system gain is 6 dB or less, no power adjustment is required.)
2. Subtract the antenna system gain from 36 dBm. The result indicates the maximum transmitter power (in dBm) allowed under the rules. In the example above, this is 28 dBm.

SWR of the antenna system

A proper impedance match between the transceiver and the antenna system is very important. It ensures the maximum signal transfer between the radio and antenna. The impedance match can be checked by measuring the SWR (standing-wave ratio) of the antenna system. The reflected power should be less than 10% of the forward power (≈2:1 SWR). Higher readings usually indicate problems with the antenna, feedline or coaxial connectors. If the results are normal, record them for comparison for use during future routine preventative maintenance. Abnormal readings indicate possible trouble with the antenna or the transmission line that will need to be corrected.

4.7 Digital radio and security

One concern with digital radio is communications security. Traditional communications channels for protection are physically isolated from computer networks, and therefore carry little security risk. However, digital radio signals are theoretically available to anyone with the proper equipment. Security issues fall into the categories of protection of privacy, protection from unauthorized access, and protection from denial of service attacks.

Protection of privacy

Unlicensed spread spectrum radios, such as those suggested for pilot protection in this paper, are inherently secure. Spread spectrum technology was developed during World War II for the military due to its ability to reject jamming and the difficulty in intercepting transmission. The tools available to hackers to intercept radio frequency messages are designed for WiFi signals. WiFi is a different communications standard than that used by digital radio, and these tools will not intercept digital radio signals.

The only practical way to intercept messages is with a stolen radio. However, all software that operates the radio resides within the radio. This prevents common hacker tricks such as putting stolen wireless cards in promiscuous mode. It's difficult to therefore actually retrieve and read the messages using just a stolen radio.

In addition, digital radios support AES-128 or RC4 encryption standards. Both AES-128 and RC4 encryption use a key. This key is required to decrypt the data. Unlike earlier encryption technology the key isn't static in that it is rotated with other keys after a short period of operation. So access to the radio still doesn't result in access to data.

THE ATTRACTION OF DIGITAL RADIO FOR PROTECTION OF SHORT DISTRIBUTION LINES IS INSTALLED COST, PARTICULARLY IN RETROFIT SITUATIONS

Protection from unauthorized access

This next level of security assumes that a hacker is already connected to the network using a stolen radio (This is a big assumption). To prevent a break-ins authentication is used to allow the radio access to the network. There are several standards revolving around authentication. For standard IT equipment such as routers, switches, and WIFI the authentication standard that applies is called 802.1x RADIUS authentication. When larger organizations implement authentication it will be 802.1x RADIUS. Digital radios can comply with 802.1x RADIUS. The same radios will also work without 802.1x RADIUS and have local authentication that will provide the user with a high level of security.

Protection from denial of service attacks

There are many different attacks. One for example would be to redirect traffic. The predominant strategy against denial of service attacks is to prevent unauthorized people from configuring the radios. To protect against dictionary attacks, which a hacker may try to break the password, radios have a feature were after three login failures, the transceiver ignores login requests for some period of time.

Digital radios can become part of a company's regular IT network. Unprotected access points on the network provide access to any connected radios. For this reason, organizations may insist upon implementing remote login to network managed devices with SSH management or HTTPS. The SSH or HTTPS management standard is basically an encrypted telnet for IT equipment configuration. This prevents someone monitoring the network to use an unsecured access point from seeing the data within the telnet session.

In addition, digital radios are compliant with SNMP version 3 which may be implemented on larger systems. SNMP version3 or Simple Network Management Protocol Version 3 (SNMPv3) is an interoperable standards-based protocol for network management. SNMPv3 provides secure access to managed devices by a combination of authenticating and encrypting packets over the network. The security features provided in SNMPv3 are:

- Message integrity—Ensuring that a packet has not been tampered with in-transit.
- Authentication—Determining the message is from a valid source.
- Encryption—Scrambling the contents of a packet prevent it from being seen by an unauthorized source.

5. Digital Radio Pilot Performance Comparison

With end-to-end performance in the 10 - 15ms range, digital radio immediately places itself in the mix of usable pilot channels in the protection and control world. Traditional pilot protection channels include Power Line Carrier, Audio Tone, and more recently digital channels via fiber (direct or multiplexed) or copper. Although not quite as fast as the total time of direct fiber or a wide-band carrier set (3.5 – 6 ms), it compares quite favorably to analog tone over an analog microwave (13 – 18ms) or a digital channel through a modem (15-18ms).

This paper explicitly discusses the use of an IEC 61850 GOOSE message transmitted over Ethernet. One reason is that Ethernet radios are an inexpensive, easy to configure solution for digital radio applications. In addition IEC 61850 is a non-proprietary solution, as the GOOSE is an international standard with demonstrated multi-vendor interoperability. The GOOSE is configurable to communicate multiple Status, Analog Values, and Quality values in a single message. The 10 – 15 ms message delivery time mentioned above is invariant for GOOSE packets containing limited combinations of the above data items. Also, using an IEC 61850 GOOSE message over Ethernet provides impressive error checking capabilities to ensure messages are correctly received. The radios use a 16-bit CRC, and the GOOSE message uses a 32-bit CRC. This larger CRC eliminates the need for security counts on received messages for permissive or blocking signals. If the CRC is validated, there is only a 1 in 4 billion chance that the received message is incorrect. Also, digital radios using Ethernet can support other communications traffic than simply protection. By using a VLAN, protection GOOSE messages will always have priority over other types of traffic, so no channel delays occur.

There are other methods to implement digital radio as a pilot protection communications channel. One possibility is to use radios that transmit physical contact closure states, similar to traditional power line carrier or microwave solutions. Another possibility is to use a proprietary pilot protection communications protocol available from various relay vendors. This method requires relays from the same vendor on each end of the line, and requires the radios can actually transmit this proprietary protocol. Depending on the method selected (contact closure or protocol), the radios selected, and the actual protocol used, the channel latency can be significantly less than that of IEC 61850 GOOSE messages over Ethernet. These methods may only work with specific models of radios, and may require the use of radios operating on licensed transmission frequencies. These methods will not use the 32-bit CRC error checking available through IEC 61850 GOOSE messaging, and may not implement the 16-bit CRC available in Ethernet-enabled digital radios.

A challenge for any radio system is interference. Interference can come from paging transmitters, co-located transmitters, receiver overload, and rectification in metal structures. The issues around interference are usually site specific, as are the solutions to eliminate interference. One common solution, especially when multiple radio transmitters are present, is to cross-polarize antennas. Most systems use vertical antenna polarization. Cross-polarizing by going to horizontal polarization in one system reduces on-channel or adjacent-channel interference by about 20 dB. Power system faults are not a concern, however. The majority of the energy for a power line fault is centered on a 10 MHZ bandwidth, and doesn't exceed 100 MHz. Spread spectrum radios operate at 900 MHZ, well above this bandwidth.

6. Pilot Protection with digital radio

Although latency through the digital radio may be a concern, when operating in the distribution realm, a system latency of 10 –15 ms is typically acceptable. A second concern may be the need for redundancy in case the radio communications fail for some reason. These are similar concerns to pilot protection for transmission line applications.

The best way to discuss these performance criteria is to look at specific examples of pilot protection using digital radio as applied to the distribution feeder supplying an industrial facility. Specifically, we'll discuss a POTT scheme, a DCB scheme, a reverse interlocking scheme, and any combination POTT/DCB scheme. This paper assumes that all protection scheme logic is performed with a microprocessor-based relay. Obviously, traditional hardwire control logic can be used as well. It is important to note that the microprocessor-based relay treats the GOOSE message the same as any other digital input. The status of the specific bit from the GOOSE message is utilized in the relay logic just the same as a regular contact input.

6.1 POTT scheme

This application of the POTT scheme (Figure 9) uses definite time directional overcurrent or distance elements. These definite time directional overcurrent elements are set to see faults beyond the other end of the line, and are configured with no intentional time delay. Instantaneous tripping is acceptable, because a permissive signal from the other end of the line is required to allow tripping. Since the relays at both ends must send a permissive signal for the POTT scheme to operate, there must be a source of the fault current for the protected line at each end of the line. Depending on the capabilities of the relay used for the POTT scheme, it may be possible to implement a weak infeed/echo logic to account for no source on one end.

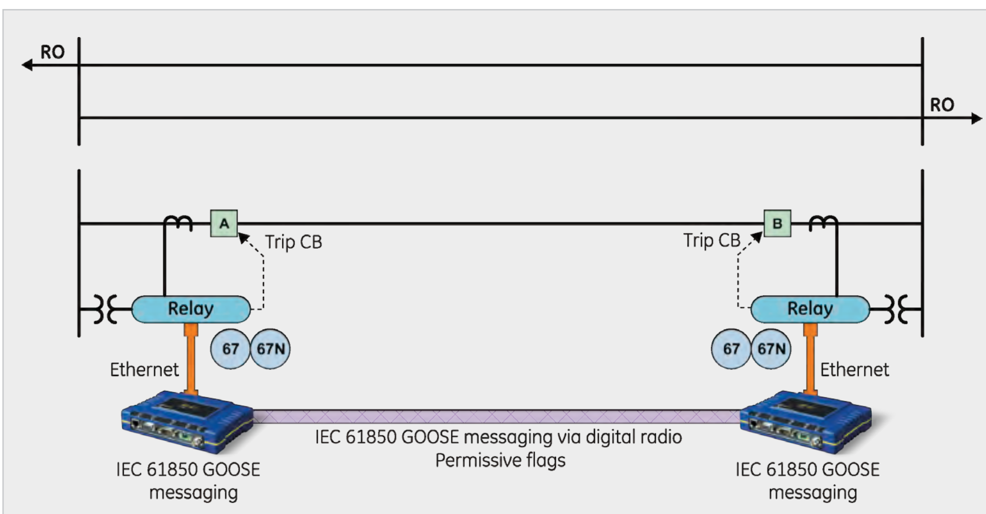

Figure 9.
POTT scheme using digital radio

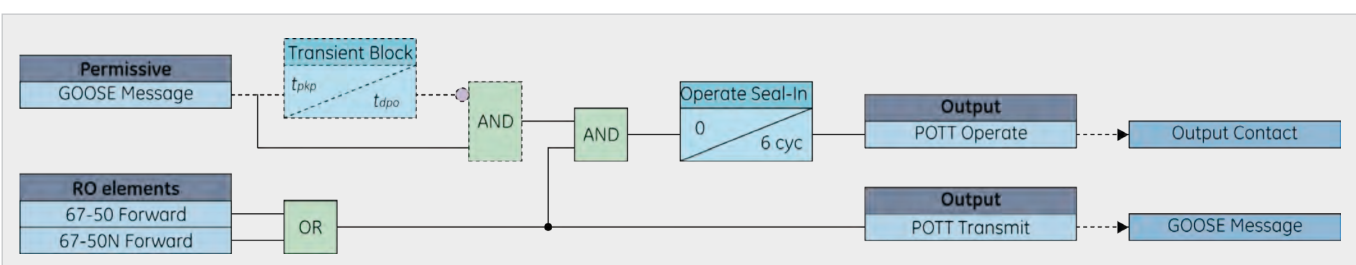

Figure 10.
POTT scheme logic

The internal relay logic for the POTT scheme is actually quite simple. When either the phase or neutral directional overcurrent element picks up, a GOOSE message containing a permissive flag is sent to the relay on the other end. If a GOOSE message containing a permissive flag is received from the other end while either of the local overcurrent elements is picked up, the relay trips the local circuit breaker. There is no intentional time delay in this scheme. For a fault on the protected line, the total operating time of this scheme will be approximately 30 to 35 ms, ignoring the breaker operating time. This assumes a channel latency of 10 to 15 ms, and approximately 20 ms for the relay element to operate.

Traditional POTT schemes (Figure 10) using analog communications such as power line carrier or microwave use a pickup time delay on the permissive receive signal in case of spurious signal reception. Since this implementation uses a digital status contained in a GOOSE message, there is no need to add this pickup time delay. There is no need to add a pickup time delay to the permissive receive signal, as this is a digital status contained in the GOOSE message. Also, there is no need to add a security count to the permissive receive signal. Validation through the 32-bit CRC of the GOOSE message ensures the received message is correct. For this simple, one line application, there is no need to add any transient blocking delay for current reversal. However, if parallel lines are serving the same facility or tied to the same bus, then a transient blocking delay for current reversal must be added on to the permissive receive signal.

6.2 DCB scheme

The DCB scheme (Figure 11) also assumes the use of definite time directional overcurrent or distance elements. The DCB scheme requires a forward directional overcurrent or distance element looking towards the protected line for tripping, and a reverse directional overcurrent or distance element looking behind the protected line to initiate a blocking signal. The reverse directional overcurrent or distance element that initiates the blocking signal is set with no intentional time delay.

The directional overcurrent or distance element that is used for tripping is set with a short time delay to account for channel delay time. This time delay can be set to approximately 4 cycles to allow for the maximum message latency of 40 ms plus approximately 1 cycle for the remote relay to initiate the blocking signal. Therefore, the total operating time for protection of the line will be 4 cycles, ignoring breaker operating time.

It may be necessary to add a short seal-in timer to hold the blocking signal (Figure 12). The blocking signal is a digital flag contained in a GOOSE message. Since the loss of one GOOSE message will cause the blocking signal to drop out, this timer ensures the blocking signal is maintained when an individual message is lost. Assuming that the blocking GOOSE message is sent in 4 ms, a 1-cycle time delay means that four consecutive GOOSE messages must be

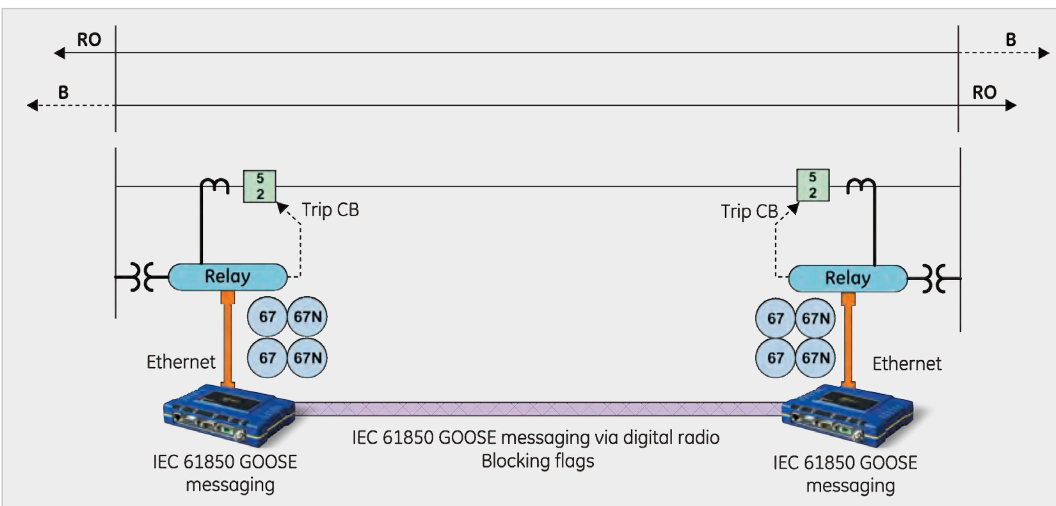

Figure 11.
DCB scheme using digital radio

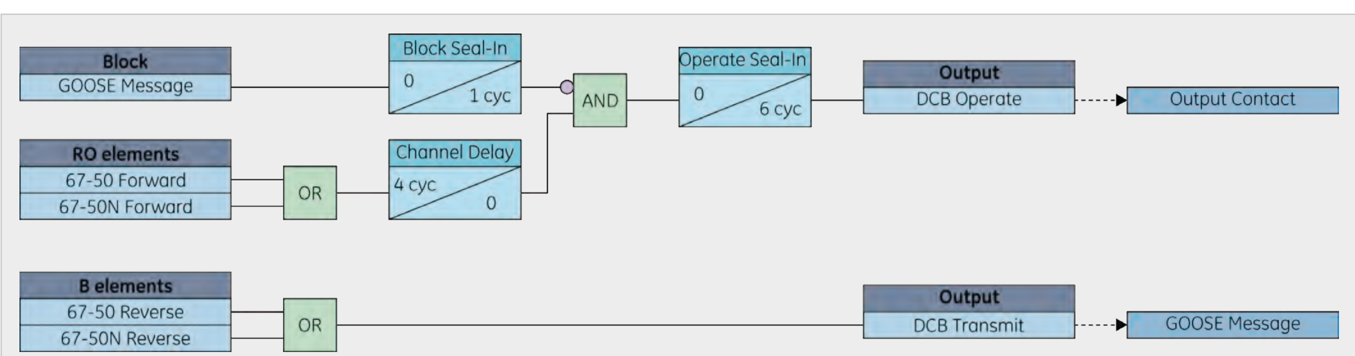

Figure 12.
DCB scheme logic

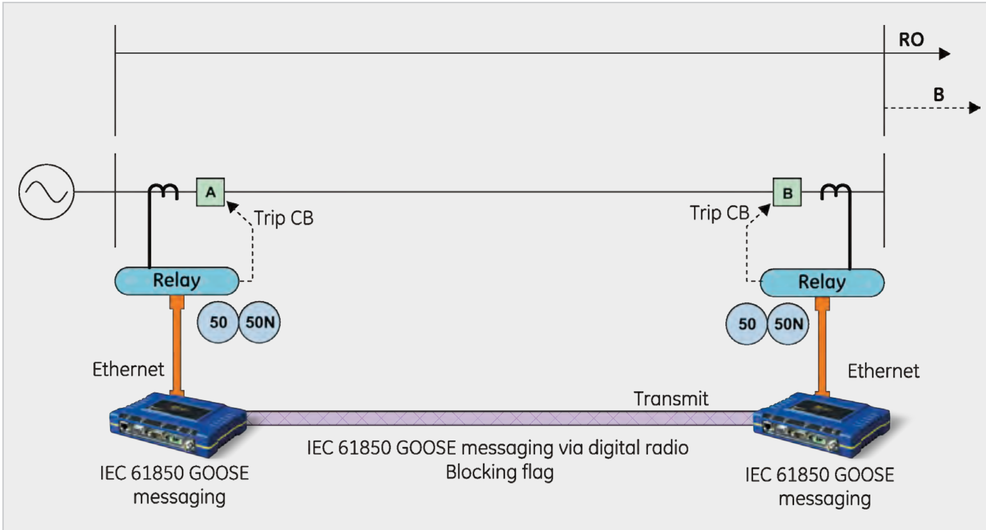

Figure 13.
Reverse interlocking scheme using digital radio

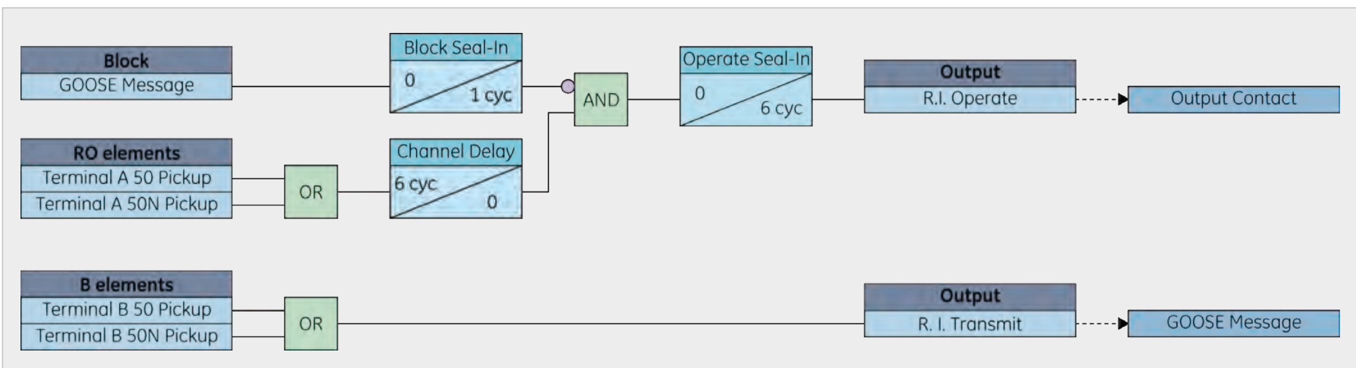

Figure 14.
Reverse interlocking scheme logic

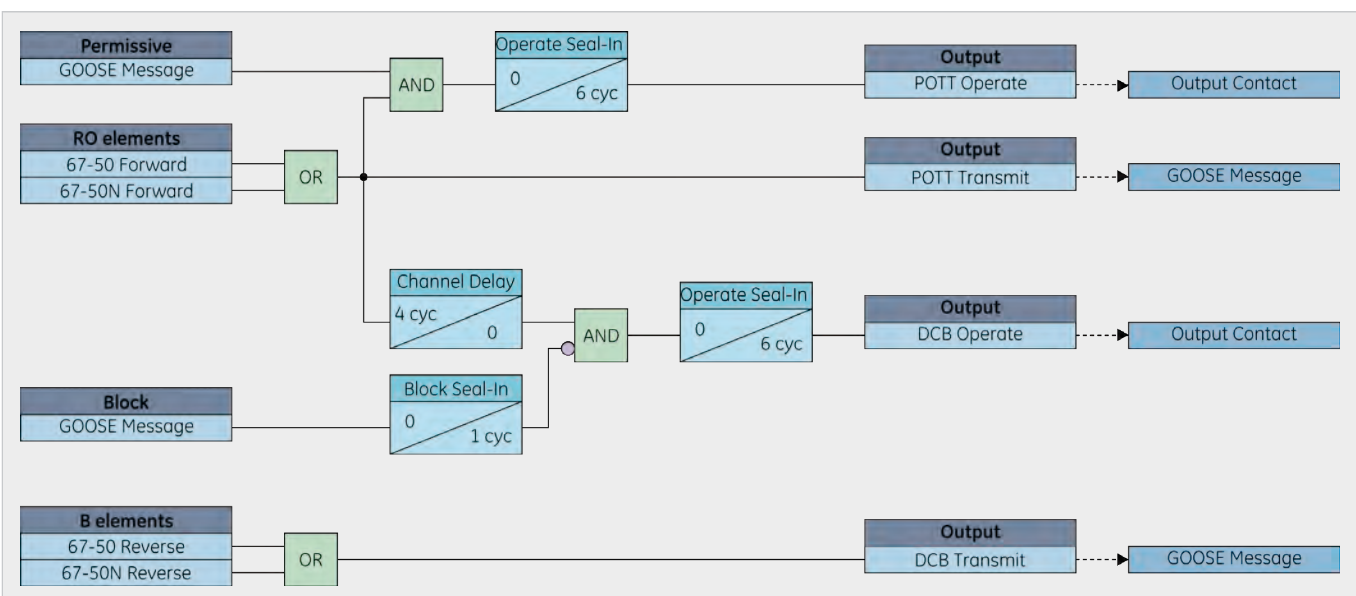

Figure 15.
POTT/DCB combination scheme logic

lost before the block is released. The 1 cycle time delay also means the blocking signal must drop out for one cycle before tripping is permitted.

6.3 Reverse interlocking scheme

Even when the distribution feeder for a large load or industrial facility is a radial feed, it may be desirable to it implement pilot protection on the incoming distribution feeder. Pilot protection should result in faster clearing times for faults, and alleviate many coordination issues. Pilot protection in this instance can be a simple reverse interlocking protection scheme (Figure 13). In a reverse interlocking scheme, both downstream and upstream relays use high-speed overcurrent protection. When the downstream relay picks up for a fault, this relay sends a blocking signal to the upstream relay. The overcurrent element on the downstream relay is set to overreach the downstream line end, and with no intentional time delay. The overcurrent element on the upstream relay is set with a short time delay of 4 to 6 cycles. The short time delay allows the downstream relay detect the fault and initiate the locking signal, and this time delay allows for maximum latency (40ms) of the digital radio message.

The logic for the reverse interlocking scheme (Figure 14) is different in the relays at the source end and the load end of the line. The relay at the load end of the line, Terminal B in this example, simply sends a blocking signal when an overcurrent element picks up. The relay at the source end of the line, Terminal A in this example, can only operate when overcurrent elements are picked up and no blocking signal is received from the relays at Terminal A. Reverse interlocking is in some ways a simpler form of the DCB scheme. The operating time is similar, but with the total clearing time for a fault of the protected line of approximately 6 cycles, ignoring breaker operating time.

IEC 61850 GOOSE MESSAGES OVER ETHERNET PROVIDES IMPRESSIVE ERROR CHECKING CAPABILITIES TO ENSURE MESSAGES ARE CORRECTLY RECEIVED

6.4 Combination of POTT/DCB scheme

For increased reliability, one possibility is to apply both the POTT scheme and a DCB scheme operating in parallel. The POTT scheme should operate essentially instantaneously for fault on the protected line. The DCB scheme, due to the need to initiate and receive a blocking signal, has a short time delay of 4 to 6 cycles. Therefore, for an internal fault, but POTT logic should trip instantaneously. If the fault fails to clear, such as for a breaker failure condition, the DCB logic will trip in 6 cycles. Consider the fault conditions if the digital radio fails. For a fault on the protected line, the POTT logic will not operate because no permissive signal is sent or received. The DCB logic will operate, as no blocking signal is sent or received. For a fault not on the protected line, once again the POTT logic will not operate. However, the DCB logic will operate, as no blocking signal is received or sent. It may be desirable to increase the time delay of the DCB logic to allow other protection to clear external faults.

This combination scheme (Figure 15) is very attractive when the line being protected is the line to an industrial facility with generation. When the facility generation is running, both the POTT and the DCB scheme will operate correctly. However, when the generation is not running, the POTT scheme will not operate correctly for fault on the protected line. The directional overcurrent relay at the plant end of the line will not see a fault on the protected line, and will therefore not send a permissive signal. However, the DCB scheme will operate correctly in this case. No blocking signal will be sent when the fault is on the protected line. However, for a fault in the plant itself, a blocking signal will be sent to the utility end of the line.

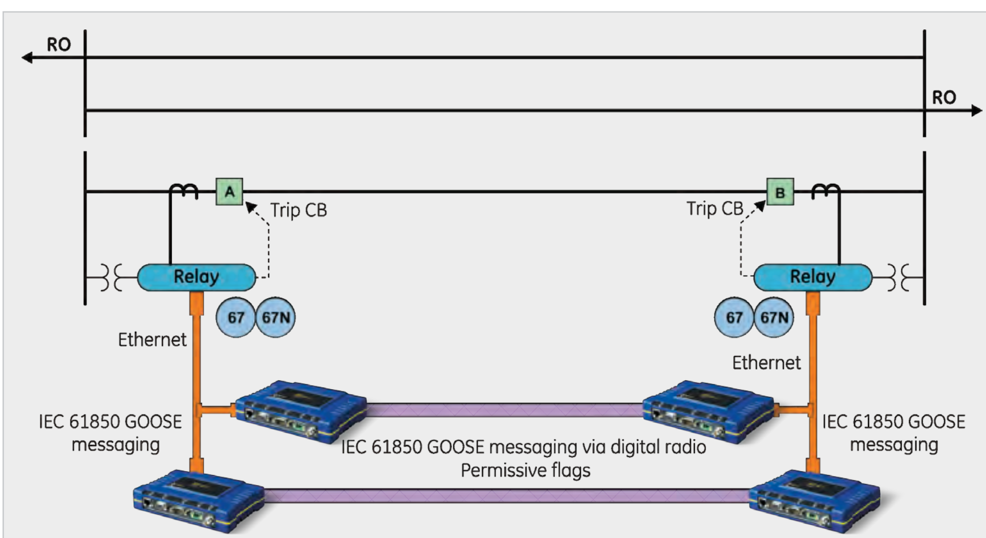

Figure 16.
POTT/DCB combination scheme logic

6.5 Scheme Considerations

These examples show that digital radio using IEC 61850 GOOSE messages can be the communications channel for the two most common pilot protection schemes. By extension, digital radio can be used in any pilot protection scheme, including Directional Comparison Unblocking (DCU), Permissive Underreaching Transfer Trip (PUTT), and the Hybrid POTT scheme. This paper uses the POTT and DCB schemes as examples to show that digital radio can perform in both a permissive logic and a blocking logic.

The POTT scheme is a very secure scheme, but will fail to operate on a loss of communications channel during an in-zone fault. The DCB scheme is a very dependable scheme, but may operated incorrectly for an out-of-zone fault during a loss of communications channel. These risks have always existed, starting with power line carrier communications. In fact, the DCU scheme using frequency shift keying is a scheme designed around the unreliability of the power line carrier signal. The correct choice of pilot protection scheme when using digital radio is therefore part of the art and science of protective relaying. Philosophy, experience, and application criteria will lead to the best solution for a specific situation.

6.6 Redundancy considerations

As with any other protection scheme, there are redundancy and backup considerations when using digital radio as part of a pilot protection scheme. The previous application of a combination POTT and DCB scheme is one such example of redundancy. If for any reason the digital radio channel fails, the line will still trip for internal faults. However, there could be a loss of security for external faults. A simple way to add redundancy is to use two separate radio paths for communications. In other words, simply use 2 separate radio sets. The same GOOSE message is sent to each radio, and both GOOSE messages are received by the relay. That way, if one set of radios fails to communicate, the other set will still operate. This method requires one of the radio sets to use cross-polarized antennas to prevent channel interference.

7. Other Applications

7.1 Other protection applications

Obviously, pilot connection using digital radio can be applied in any network distribution line application including a line serving IPPs, and networked distribution lines downtown load centers. However, when the digital radio used is an Ethernet-based radio, the radio essentially establishes an Ethernet network between remote devices. This allows the extension of the protection scheme in interesting ways.

Parallel feeders

Parallel feeders from a utility serve some industrial facilities. In this case, separate pilot protection systems are required for each incoming distribution line. However, with digital radio, one set of radios can be the communication channel for multiple sets of lines. Each relay simply sends a GOOSE message to the radio, or receives a GOOSE message from the radio, as appropriate. Using two sets of radios in this case provides complete reliability of communications. Each pilot protection system sends its tripping or blocking signals over both sets of radios. Therefore both lines have a primary and secondary communications channel while requiring only two sets of radios. To extend this example even further, consider a plant that has three incoming utility feeds. Two sets of radios provide a redundant communications path for all three incoming feeders.

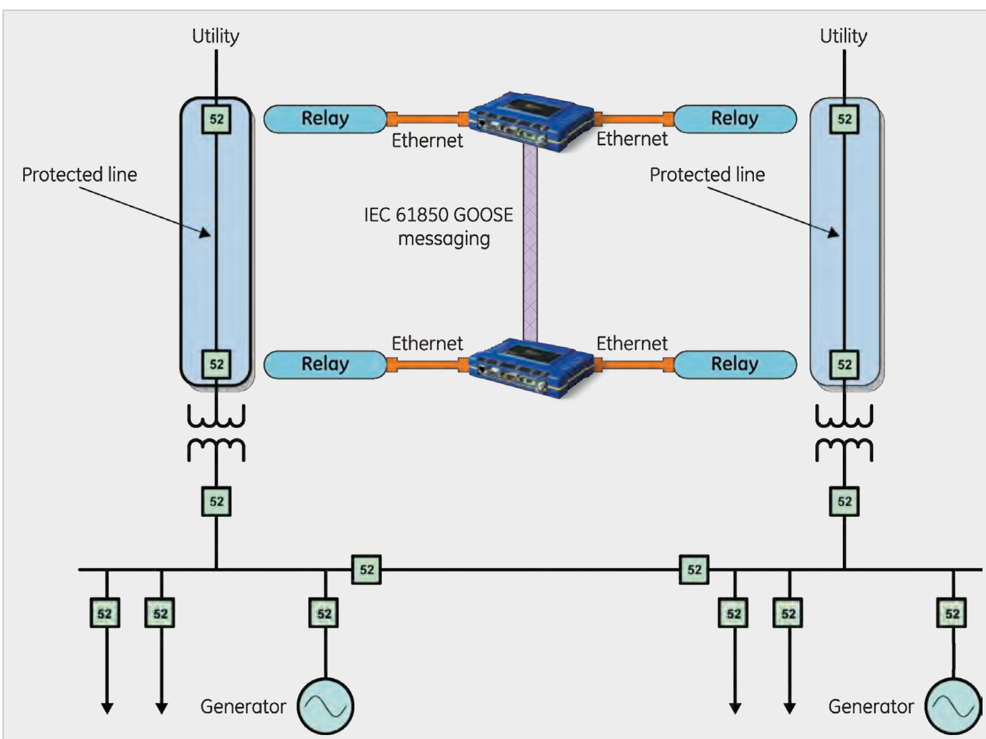

Figure 17.
Parallel feeder application

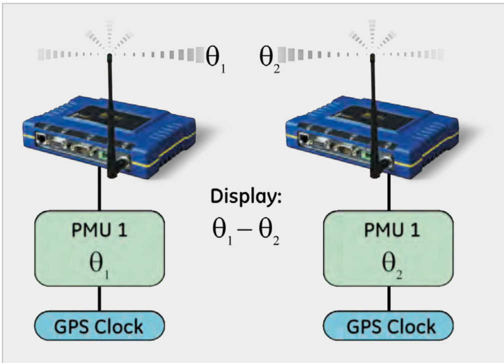

Figure 18.
Mobile phase angle verification system

7.2 Other Digital Radio Channel Applications

Given a digital communication channel in a substation, a wide variety of ancillary functions become available. When using a digital radio channel in an application, the channel is available 99.9% of the time for other applications. In the case of an Ethernet-based radio, the Ethernet can be connected to all other devices in the remote substation and provide complete data access. This access would typically include SCADA (with remote control), remote setting/SW updates, oscillography and Sequence of Events retrieval, and physical security monitoring.

Besides the typical substation functions mentioned above, digital connectivity enables the ability to transmit digital images. Specifically, many remote control functions require visual confirmation of an operation such as the opening of a disconnect. By providing a position-selectable camera, an operator can position the camera to focus on a substation device (e.g. – switch), visually check the status of the device before the control operation, execute the control operation, and then verify the result of the operation.

Another recently field-tested application had to do with mobile verification of the angle reference of distribution feeders. In this application, there was an operational need to be able to verify the phasing between a substation source and the service in a customer location. The distance between the substation and the customer premises could range from dozen's of meters to 2km. The solution of this mobile monitoring application was the use of a set of Phasor Measurement Units (PMU) – synchronized by a set of GPS clocks – and communicating with GOOSE through Ethernet digital radios. Each PMU measured the absolute local angle (either the source angle or the customer's service angle) and each end then communicated the measured angle to the other via GOOSE. The received angle was subtracted from the locally measured absolute angle and the relative difference was then displayed. This system is illustrated in Figure 18.

8. Summary

This paper describes basic digital radio technology and shows some possible applications of digital radio for distribution protection. As with any other pieces of the protection system, it is important to understand the reliability and performance of digital radio. The test results documented in this paper show that digital radio successfully sends an IEC 61850 GOOSE message within 10 to 15 ms 99% of the time. In no case during the test was a message not received. Therefore digital radio is reliable enough to use as part the distribution protection system. The 10 to 15 ms channel latency is more than acceptable for distribution protection, is interoperable, and requires no special adaptation of standard pilot protection schemes. The channel latency compares quite favorably to that of analog tone over an analog microwave, or a digital channel through a modem, meaning that digital radio is appropriate for pilot protection communication on sub-transmission lines.

Advantages of digital radio in being able to establishes an Ethernet network was presented. Additionally, digital radios support any standard protocol over Ethernet, including Modbus, DNP 3.0, and IEC 61850. At a minimum, this allows digital radio to send the binary signals necessary for pilot protection, such as permissive and blocking signals. In addition, digital radio, like any other Ethernet network, allows simultaneous traffic. Therefore digital radio can support communications for pilot protection, SCADA communications, and metering communications simultaneously without any degradation in performance.

When one looks at the capabilities of digital radio, and the low installed cost of digital radio, many interesting applications present themselves.

9. References

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9. Symbols

Symbol	Definition
	Current source
52	Circuit Breaker
Relay	Digital Relay
Radio	Digital Radio
67 67N	Directional Overcurrent (Phase and Neutral)
RO	Overreaching protection element
B	Blocking protection element
AND	Logical AND
OR	Logical OR
Timer t t	Timer element
	Ethernet connection

041310-v4

Fault Locator Based on Line Current Differential Relay Synchronized Measurements

Ilia Voloh, Zhiying Zhang
GE Digital Energy

William J. Premerlani
GE Corporate Research and Development

1. Introduction

The ability to accurately determine the location of faults on power systems lines are important as they facilitate faster inspection and shorter repair times, leading to faster restoration of the faulted lines. This greatly increases system reliability. At the same time, accurate fault location is a technical challenge because the fault location estimation is done based on the limited amount of information gathered at the line terminals. Problems which must be overcome include finite transmission line parameters accuracy, instrument measurement errors, coupling to adjacent transmission lines, unknown and often nonlinear fault resistance, finite duration of faults resulting in short time window opportunity to capture necessary data.

The most common approach is to use voltage and current measurements from a single line terminal to estimate the fault location using various assumptions and approximations. Such approaches are referred as impedance-based single-ended methods and are nowadays a standard built-in function in the transmission line relays. All these methods are based on a certain assumptions due to lack of accurate information to solve equations. When assumptions are satisfied for a given fault situation, the fault result is accurate. When the assumptions are not satisfied, significant error may occur. Impedance based methods are challenged by too many factors, including but not limited to;

- Parallel lines mutual coupling
- Uncertainty in K0 factor
- Fault resistance and power flow
- System homogeneity
- Weak infeed applications etc

Fault location systems that utilize information from more than one line terminals are referred to as multi-ended fault locators. A multi-ended fault locator eliminates the key weaknesses of a single-ended approach, but requires communication channels to rely data from geographically dispersed line terminals to a single location where the actual fault location calculations are performed. Some multi-ended methods don't require synchronization of the data between line terminals. Accuracy of such non-synchronized measurements methods is affected by following factors:

- Variable in time arc resistance produces variations in phasors values.
- Transients in voltages and currents due to system response to the fault and instrument transformers transients.
- Transients in phasors measurement due to filtering and phasor estimation. Time window to capture phasors for accurate result transient "pre-fault to fault" is shortly followed by the switch-off transient. With a modern 1.5 or 2 cycles breakers operating time capturing fault steady state phasors becomes short, therefore challenging to capture correct values.
- Fast-evolving faults may produce a set of phasors and fault types at line terminals, which do not match each other, if phasors are not captured at the same instance.

Some methods are using positive-sequence or negative-sequence voltages and currents. Three-phase balanced faults do not produce any negative-sequence signals Therefore such method has to add the positive-sequence based equations to eliminate this weakness. As a result, two sets of calculations must be run in parallel, or coarse fault type identification must be performed. Purely negative-sequence method produces nearly zero result for currents and voltages for three-phase balanced faults.

A typical single or multi-ended fault locator requires knowledge of the fault type, i.e. which and how many conductors are involved in the fault, knowledge of the mutual coupling to adjacent lines located on the same towers or in close proximity, and some other auxiliary information. The remote portion of the multi-ended locator mentioned above needs to send both negative and positive-sequence based signals, or the two portions of the locator must work flawlessly in terms of fault type identification. These extra factors are found through separate procedures, and if delivered to the main fault location procedure with errors, they will impact the overall fault location accuracy.

This paper presents a new patent pending multiended systems working in real time, such as locators integrated within line current differential relays protection relays, taking advantage of data transmitted already between terminals and adding minimum transmitted data to not exceed bandwidth requirements for 87L communications.

2. New Method

2.1 Goals of a new method

Goals of a new method were as following:

- Take advantage of the transmitted synchronized per-phase phasors for the line current different protection. Line current differential operates nearly at the same time, thus capturing fault phasors at practically same instance.

COMPUTE THE FAULT LOCATION WITHOUT ASSUMPTIONS OR APPROXIMATIONS, USING THE COMPOSITE SIGNALS AND ASSOCIATED NETWORK ONLY

- Two-or-three terminal applications should be covered. In three terminal applications the algorithm reports the affected section of the line (T1T, T2T, T3T), and the fault location from the terminal closest to the fault (fault is between this terminal and the tap).
- It is preferred to minimize the amount of extra information added to the line current differential packet.
- Eliminate fault location error due to mutual coupling, fault resistance, load, nonhomogeneity, nonsynchronized measurements.
- Eliminate reliance of the algorithm on the phase selection information for fault location. A single set of fault location equations applies to all fault types and phase involvement. However, phase selection information can be used for determination of fault resistance.
- Take advantage of compensation of the line charging current: the positive impact of the compensation shall be passed on the fault location algorithm by using compensated currents versus measured currents.
- It is preferred to include compensation for mutual coupling with a parallel line. The mutual coupling is characterized by the neutral current of the parallel line (3I0) wired to the ground current input of the relay, and measured by this relay as a phasor.
- It is desirable that algorithm reports fault resistances when possible. If relevant for accuracy, the algorithm shall assume multiple fault resistances for multiphase faults and match such fault models to the measured currents and voltages. For example, single line-to-ground and line-to-line faults are modeled with 1 unknown resistance, double line-to-ground faults could be modeled with 2 or 3 unknown resistances, etc.
- Make fault location results available at all terminals immediately after fault.
- During line current differential channel failures provide single-ended fault location result at each terminal as a backup.

The new fault detection system is based on the idea that synchronized voltage and current measurements at all ends of the transmission line make it possible to use network equations directly to compute the fault location without assumptions or approximations, using the composite signals and associated network only. The composite signal is created in such a way that regardless of the fault type, there is a disturbance in the composite signals. The composite voltage at the fault can be computed from each end of the line by subtracting the line drop to the fault from the voltage at that end using the composite voltages at the terminals, composite currents and appropriate impedance. There are more equations in this composite signal model than unknowns, so that it is possible to solve for the fault location that will match the fault voltage estimates made from all ends of the line. This simplifies the system and makes it highly accurate by removing both assumptions and model parameters that may have inherent accuracy limitations such the zero-sequence impedance of the line. The systems and calculations for two-ended and three-ended systems are similar and will be described further.

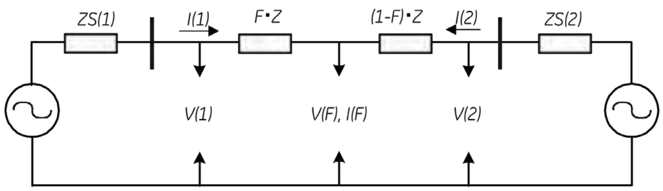


Figure 1.
Two-terminal line model

2.2 Two-terminal line

The two-ended system executes an algorithm on measurements separately on each terminal. Either result is sufficient to locate the fault. Both terminals will compute exactly the same fault location, since they use exactly the same equations applied to the same data. This could be summarized that the calculations are symmetrical in terms of identical equations executed at both ends of the line, and redundant in terms of the results remaining in the a prior known relationship. Thus, the two-ended system can compare the results of the calculations to ensure accuracy. In a further embodiment of the two-ended system, the system can be configured to subsequently calculate fault resistance at each terminal from the fault location plus local measurements, so that each terminal may compute a slightly different estimate. The two estimate values can be averaged to increase accuracy.

The system algorithm is based upon the following fault measurements and settings with reference to Figure 1:

I(1)=composite current phasor flowing into the line at first terminal

I(2)=composite current phasor flowing into the line at second terminal

V(1)=composite voltage phasor at first terminal

V(2)=composite voltage phasor at second terminal

Z=complex line impedance

L=line length between first and second terminals,

F=fraction fault location from first terminal

D=F·L=distance from first terminal to fault location

The new algorithm uses generalized Clarke transform to represent voltages and currents for the purpose of fault locating. The traditional Clarke transform works for both instantaneous and phasor values, and uses the following equation for one of its components:

$$V = \frac{2 \cdot VA - VB - VC}{3} \quad \text{(Eq. 1)}$$

The above has a weakness of zeroing out currents for BC faults, and as such does not meet the requirement of delivering a signal representing the fault under all circumstances. Therefore equation (1) is generalized by this invention as follows:

$$V = \frac{2 \cdot VA - b \cdot VB - b^{*} \cdot VC}{3} \quad \text{(Eq. 2)}$$

Where b is a complex number given by:

$$b = 1 + j \cdot \tan(\alpha) \quad \text{(Eq. 3a)}$$

and b* is a conjugate of b, or mathematically:

$$b^{*} = 1 - j \cdot \tan(\alpha) \quad \text{(Eq. 3b)}$$

where alpha is an arbitrary angle. Note that with alpha=0, the generalized Clarke transform of this invention becomes the traditional Clarke transform. This particular implementation uses $\alpha = \text{pi}/4$, or 45 degrees. It shall be noted, however, that many angles meet the requirements of representing any type of fault and being not sensitive to the ground current coupling. Also, it shall be noted that many other combinations of the phase signals (A,B,C) make the requirements of representing any type of fault and being not sensitive to the ground current coupling. This algorithm ensures that a single signal is created to represent the three measured signals (A,B,C) for the fault location purposes, in such a way that the ground currents do not affect the said signal, and the said signal is nonzero for all fault types

Both phase currents (IA,IB,IC) and voltages (VA,VB,VC) at all the points of interest are converted into the composite signal such as the generalized Clarke transform using the same transformation method throughout the network of interest. This conversion takes place in the line current differential relays that locate the faults, and is performed mathematically on all signals when deriving the fault location method and equations.

In the case of phase current measurements that are compensated for charging current of the transmission line, the compensated phase current phasors are used when deriving the composite current signals, and will provide a fault location estimate that takes full advantage of the compensation. Effects of charging current are described further below.

The fractional fault location is given by:

$$F = \text{Real}\left[\frac{\dfrac{V(1) - V(2)}{Z} + I(2)}{I(1) + I(2)}\right] \quad \text{(Eq. 4)}$$

Equation (4) takes advantage of redundancy in the data. There are more equations than unknowns, so a least mean squares fit is used. The equation is independent of faulted phase, fault type, fault resistance, and zero-sequence (ground current) coupling to an adjacent transmission line, if any.

It is important to understand the value of the total line impedance of the transmission line, Z, used in equation (4). This value is a complex ratio of the composite voltage and composite current measured at one end of the line with the other end under fault. Note that the fault type is not relevant, and the said ratio, will be the same regardless of the fault type. Practically this impedance is equal to the negative or positive sequence impedance of the line and is readily available.

Equation (4) can be computed at either or both first and second line terminals, producing exactly the same fault location estimate, except measured from opposite ends of the line. As one will recognize, the roles of the two terminals are exchanged when changing the terminal at which equation (4) is computed. The two F values should sum identically to 1.

2.3 Three-terminal line

The two-terminal algorithm described above is readily extended to a three-terminal system, such as shown in Figure 2. The situation for a three-terminal system is illustrated for the case in which the fault is on the line from the first terminal to the tap. The situations for a fault located on one of the other two line segments are not shown, but can be obtained by a cyclic permutation of line indices.

The three-terminal system executes an algorithm at each terminal that has information from all three terminals. In the case where one communication channel is down, this may be only one of the three terminals. The system algorithm has two parts—one part that determines which line segment is faulted, and a second part that locates the fault on the faulted segment. As with the two-terminal system, the algorithm will calculate exactly the same fault location from each terminal.

The following measurements and parameters are assumed to be available:

I(1), I(2), I(3)=composite current phasors flowing into first, second and third line segments

V(1), V(2), V(3)=composite voltage phasors at first terminal, second terminal, and third terminal

Z(1), Z(2), Z(3)=complex composite impedance of first, second and third line segments

L(1), L(2), L(3)=line lengths of first, second and third line segments

It is, of course, the goal to determine which line segment has fault, and the distance of the fault from the corresponding line terminal. The following parameters are used to determine the line with fault and distance from a given terminal to the fault:

N=terminal index of the faulted line segment (N=1, 2, or 3)

F=fractional fault location from Nth terminal

D=F·L(N)=distance from Nth terminal to fault location

Initially, three separate estimates of the voltage at the tap are made, assuming unfaulted condition between the tap point and a given terminal, starting at each of the first, second and third terminals. The fault location algorithm thus uses the following estimates of the tap voltage:

$$\begin{aligned} VT(1) &= V(1) - I(1)\cdot Z(1) \\ VT(2) &= V(2) - I(2)\cdot Z(2) \\ VT(3) &= V(3) - I(3)\cdot Z(3) \end{aligned} \qquad \text{(Eq. 5)}$$

where VT(1), VT(2) and VT(3) are the tap voltages calculated from each of the first, second and third terminals, respectively.

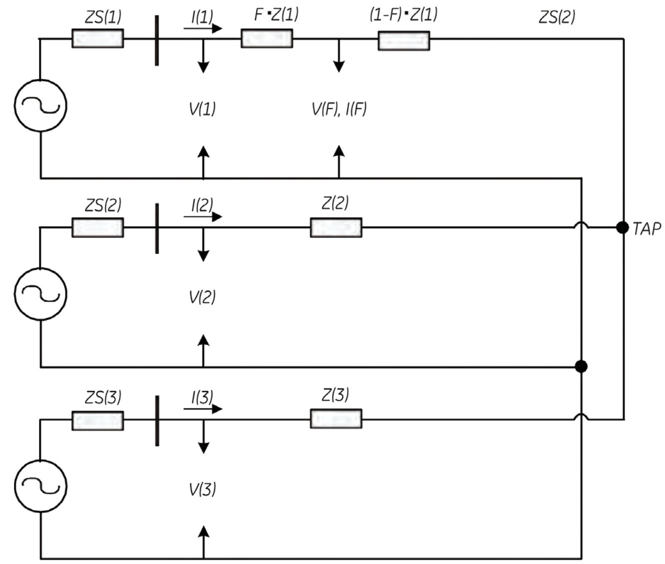


Figure 2.
Three-terminal line fault location model

Next, the line segment containing the fault is determined. Recognizing that the voltage drops around a loop through the unfaulted line segments will sum to zero can do the determination of the line. Residual voltage phasors are computed for each loop. The loop with the lowest residual voltage contains the two unfaulted line segments. In other words, only one line segment is faulted and the two unfaulted segments allow the two terminals to estimate the real tap voltage. As a result if a given pair of terminals determines the same tap voltage, the fault must be between the tap and the third terminal. The following equations are used to calculate the squared magnitudes of the residual voltage phasors in each loop as indicators:

$$\begin{aligned} R^2(1) &= \left|VT(2) - VT(3)\right|^2 \\ R^2(2) &= \left|VT(3) - VT(1)\right|^2 \\ R^2(3) &= \left|VT(1) - VT(2)\right|^2 \end{aligned} \qquad \text{(Eq. 6)}$$

where R2(1), R2 (2), and R2 (3) are the squared magnitudes. The index, N=1, 2 or 3, of the line containing fault is the same as the smallest residual voltage phasor indicator. In the case where all of the indicators R2 (1), R2 (2), and R2 (3) are approximately equal to each other, then the fault is close to the tap.

Once the index N of the line, containing fault is determined, the fault is located using a formula derived for the two-terminal lines fed with data appropriate for that line segment. Each formula is obtained from any of the other formulae by a cyclic permutation of the indices N. The formulae for each index or line are given below. First, a best estimate of the voltage phasor at the tap point and the fault current contribution from the tap are computed using current phasors and the tap voltage estimates computed in equation (5), above:

$$\begin{aligned} &\text{if } N=1: VT = \frac{VT(2)+VT(3)}{2};\ IT = I(2)+I(3);\ Z = Z(1) \\ &\text{if } N=2: VT = \frac{VT(1)+VT(3)}{2};\ IT = I(1)+I(3);\ Z = Z(2) \\ &\text{if } N=3: VT = \frac{VT(1)+VT(2)}{2};\ IT = I(1)+I(2);\ Z = Z(3) \end{aligned} \qquad \text{(Eq. 7)}$$

The fractional fault location from the terminal end of the line segment, containing fault is then computed from the terminal and tap current and voltage phasors. The tap point acts exactly as the other terminal in the two-terminal algorithm.

$$\begin{aligned}
&\text{if } N=1: F=\text{Real}\left[\frac{\dfrac{V(1)-VT}{Z}+IT}{I(1)+I(2)+I(3)}\right]\\
&\text{if } N=2: F=\text{Real}\left[\frac{\dfrac{V(2)-VT}{Z}+IT}{I(1)+I(2)+I(3)}\right]\\
&\text{if } N=3: F=\text{Real}\left[\frac{\dfrac{V(3)-VT}{Z}+IT}{I(1)+I(2)+I(3)}\right]
\end{aligned} \qquad \text{(Eq. 8)}$$

The actual distance down the particular line is subsequently computed by multiplying the fractional distance by the length of the affected line segment D=F·L(N).

Equation (8) can be implemented at any or all of the three terminals that have the necessary information available. All three results will be identical. It should be noted that some care must be taken with the fact that the three terminals have different indices within each terminal in a peer-topeer architecture such as described in the embodiment of Figure 2. As will be appreciated, if all three communications channels are in operation, then all three terminals can compute the fault location, whereas, if only two are in operation, then only one terminal can perform the computation—the terminal, which is connected to both operational channels. If only one channel is operational, then faults cannot be detected or located using the system. As will be understood, all of the required measurements can be obtained and calculations can be made using conventional single-ended method.

2.4 Three-terminal line

Fault resistance can be computed as well. Once the fault is located, it is a simple matter to estimate the fault resistance. The details depend on the fault type and the number of terminals. The following explanation considers the two-terminal equations. The three-terminal equations are similar, and are easy to understand how to obtain those equations from the two-terminal explanation below.

For a single line-to-ground fault, the fault resistance is estimated by taking the real part of the ratio of the fault voltage and current phasors for the faulted phase. The voltage phasor is estimated by starting at the terminal end, where phase voltage phasors are known and subtracting the voltage drop at the fault. The possible effects of the mutual coupling from an adjacent line are considered. Figure 3 demonstrates some typical configurations of mutually coupled lines: a) partially coupled lines originated at one bus but terminated at different buses; b) partially coupled three-terminal lines; c) double circuit line originated and terminated at the same buses; d) three-terminal line with mutually coupled two legs to the tap only. It should be noted that (c) configuration only is preferred to apply mutual coupling compensation for the fault location purposes (same as for distance relaying as well). Other three configurations are not feasible for implementation using new method, as 3I0 current from parallel line is not measured at all terminals. It means that 3I0 current from parallel line should be transmitted in the packet to all terminals, which increases packet of 87L data very much, especially in the case of three-terminal line.

With reference to Figure 1 and Figure 4, the case of a phase A to ground fault is considered. The equations for B to ground faults or C to ground faults are similar, except the quantities from the appropriate phase are used.

First and most important is that fault location result is not impacted by the mutual coupling and gives correct fault location result as shown in previous calculations above. Next we calculate the portion of mutual coupling:

$$\text{if}(D<L_m)\ F_m=D/L_m \ \text{else}\ F_m=1 \qquad \text{(Eq. 9)}$$

which means that if fault on the line, then mutual coupling impedance of the portion F_m of line involved in the fault, is considered to calculate zero-sequence voltage drop due to mutual coupling.

Estimate the phase to ground phase A voltage at the fault from local relay:

$$V_A(F)=V_A(1)-F\cdot\left((I_A(1)-I0(1))\cdot Z1+I0(1)\cdot Z0\right)-F_m\cdot I0_m\cdot Z0_m \qquad \text{(Eq. 10)}$$

where I0m is zero-sequence current measured from the parallel line ($I0m = 3I0_m/3$) and $Z0_m$ is a mutual impedance of the line and compute phase A current at the fault location:

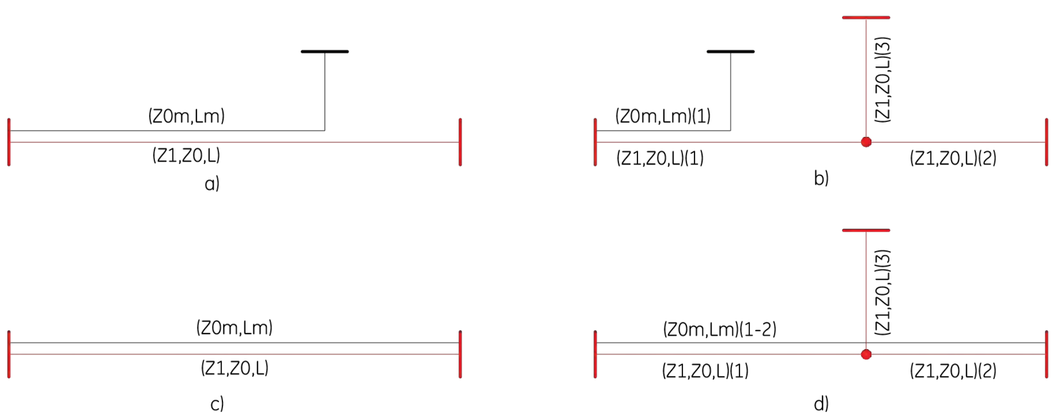


Figure 3.
Typical configurations of mutually coupled lines

$$I_A(F) = I_A(1) + I_A(2) \quad \text{(Eq. 11)}$$

where index 1 refers to current measurement from local terminal and index 2 refers to current measurements from the remote terminal.

Finally, compute the fault resistance:

$$R_A(F) = \mathrm{Real}\left(\frac{V_A(F)}{I_A(F)}\right) \quad \text{(Eq. 12)}$$

Analysis of the phase-to-phase fault is simpler, because we do not have to worry about zero sequence coupling. The following is the result for a phase A to B fault.

First, estimate the phase-to-phase voltage at the fault:

$$V_{AB}(F) = \left(V_A(1) - V_B(1)\right) - F \cdot \left(I_A(1) - I_B(1)\right) \cdot Z1 \quad \text{(Eq. 13)}$$

Estimate the phase-to-phase fault current:

$$I_{AB}(F) = \frac{1}{2}\left(I_A(1) + I_A(2) - I_B(1) - I_B(2)\right) \quad \text{(Eq. 14)}$$

Finally, compute the phase-to-phase fault resistance, using result of equations above:

$$R_{AB}(F) = \mathrm{Real}\left(\frac{V_{AB}(F)}{I_{AB}(F)}\right) \quad \text{(Eq. 15)}$$

The B to C and C to A cases are similar, with a cyclic permutation of the phase indices.

For the three-phase fault situation, an equivalent fault resistance is reported as the real part of the ratio of the positive sequence voltage to current at the fault. In the case of a three-phase fault, a somewhat better estimate of the voltage at the fault can be constructed by averaging the estimates using positive sequence voltages and currents from both ends:

$$V(F) = \frac{1}{2}\left(V(1) - F \cdot I(1) \cdot Z1 + V(2) - (1 - F) \cdot I(2) \cdot Z1\right) \quad \text{(Eq. 16)}$$

The fault resistance is:

$$R(F) = \mathrm{Real}\left(\frac{V(F)}{I(1) + I(2)}\right) \quad \text{(Eq. 17)}$$

Finally, the case of an A phase to B phase to ground fault is considered, using the following fault resistance model in Figure 4:

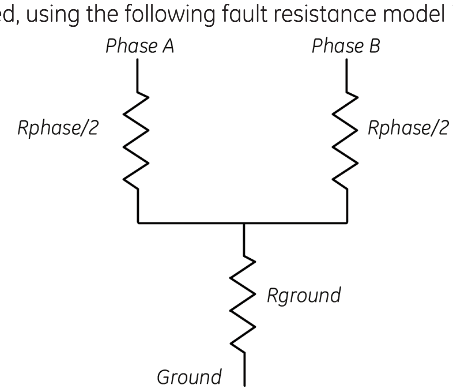


Figure 4.
Fault resistance model

Because of the involvement of the zero sequence network, the equations for fault voltage for the single line to ground fault are applied to both phases:

Compute the distance to the fault and mutual coupling impedance of the portion F_m of line involved in the fault as for single-line-to-ground fault above:

Estimate the A phase to ground voltage at the fault:

$$V_A(F) = V_A(1) - F \cdot \left(\left(I_A(1) - I0(1)\right) \cdot Z1 + I0(1) \cdot Z0\right) - F_m \cdot I0_m \cdot Z0_m \quad \text{(Eq. 18)}$$

Estimate the B phase to ground voltage at the fault:

$$V_B(F) = V_B(1) - F \cdot \left(\left(I_B(1) - I0(1)\right) \cdot Z1 + I0(1) \cdot Z0\right) - F_m \cdot I0_m \cdot Z0_m \quad \text{(Eq. 19)}$$

Compute the A phase fault current:

$$I_A(F) = I_A(1) + I_A(2) \quad \text{(Eq. 20)}$$

Compute the B phase fault current:

$$I_B(F) = I_B(1) + I_B(2) \quad \text{(Eq. 21)}$$

Compute the phase-to-phase resistance:

$$R_{ph}(F) = 2 \cdot \mathrm{Real}\left(\frac{V_A(F) - V_B(F)}{I_A(F) - I_B(F)}\right) \quad \text{(Eq. 22)}$$

Finally, compute the ground resistance:

$$R_{gr}(F) = \frac{1}{2} \cdot \mathrm{Real}\left(\frac{V_A(F) + V_B(F)}{I_A(F) + I_B(F)}\right) \quad \text{(Eq. 23)}$$

Thus, the resistance of the fault can be computed in different ways as described above to account for fault type and mutual coupling. The fault resistance information combined with the fault location enables operators of power transmission lines to more effectively manage their systems. As discussed above, the information can be obtained from any terminal connected to the minimum number of other terminals to receive the necessary data for determining the fault location and/or fault resistance.

For fault resistance calculations, fault type should be determined first. Phase-segregated line current differential principle is the best phase selector. First of all, line differential protection triggers fault location algorithm for the line internal faults only. Secondly, weak infeed, load, fault resistance and other factors, which challenge impedance based or sequence components based methods, do not affect line differential faulted phase determination. Thirdly, it provides symmetrical fault type identification at all line terminals and same fault location result. If, however, sequence components differential element operates, such as neutral or negative sequence differential, then determination of the faulted phase for SLG fault is still needed using outside of line differential means.

2.5 Charge current compensation

If the line current differential relay is capable of performing charging current compensation, it is possible to extend the benefits of charging current compensation into fault location.

Charging current compensation usually in the relay is based on a simple lumped approximate model of charging capacitance for both zero-sequence and for non-zero-sequence. For the algorithms considered in this paper, only the positive sequence model is relevant.

Since the fault location system utilizes the composite signal network, the model circuit shown in Figure 4 approximates the network reasonably well. The normal (unfaulted) system state model is equivalent to presuming that the total charging current depends on the total line capacitance and the average of the voltages V(1), V(2) at both ends of the lines. The implicit assumption in this current compensation model is that the voltage on the line varies linearly along the line from one end to the other. This is true during normal (unfaulted) conditions, but is not true during faulted conditions. Accordingly, the result is that these assumptions are violated by a fault condition. This works well for fault detection, but requires a further investigation of the effect of charging current on fault location.

IT IS POSSIBLE TO EXTEND THE BENEFITS OF CHARGING CURRENT COMPENSATION INTO FAULT LOCATION

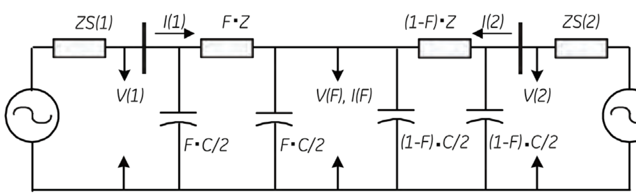


Figure 5.
Faulted line model with charging current

During a fault, the voltage profile on the line is approximately two straight lines from the terminals to the fault, which results in the model shown in Figure 5. If a device is operating on the system in a charging current compensation mode, the composite current phasors on each line become:

$$\hat{I}(1)=I(1)-j\omega\frac{C}{2}V(1)\ ;\ \hat{I}(2)=I(2)-j\omega\frac{C}{2}V(2) \qquad \text{(Eq. 24)}$$

where C is the capacitance understood as the representing the composite charging current of the line under a composite excitation voltage. In practical situations this capacitance is equivalent to so called positive or negative sequence capacitances of the line.

The equation for the composite voltage drop from the first terminal to the fault, as shown in Figure 5, is:

$$F\cdot I(1)\cdot Z=V(1)\cdot\left(1+F^2\cdot j\omega\frac{C}{2}\cdot Z\right)-V(F) \qquad \text{(Eq. 25)}$$

and the voltage drop from the second terminal to the fault is:

$$(1-F)\cdot I(2)\cdot Z=V(2)\cdot\left(1+(1-F)^2\cdot j\omega\frac{C}{2}\cdot Z\right)-V(F) \qquad \text{(Eq. 26)}$$

It can be noticed from equations 23 to 25 that both current and voltages are affected line shunt capacitance, thus introducing an error in fault location result if not compensated for jωC factor. For 100 miles line the error in fault location is about 0.2%, but for 500 miles is as high as 5%.

3. Comparative testing with single-ended methods

For the purpose of illustration of the new algorithm and a comparison with single-ended fault locators, RTDS testing with a sample line was carried out. Line under testing was 345kV double circuit line 99.5 miles length, with Z1=61.3Ω∠84.7°, Z0=192.8Ω∠73.1° and mutual coupling Z0M=110.6Ω impedances. Sources: S1 (where single-ended fault locators were located) S1Z1=23.07Ω∠79°, S1Z0=23.7Ω ∠75.3° impedances and S2 were S2Z1=40.9Ω∠86°, S2Z0=81.35Ω∠77°.

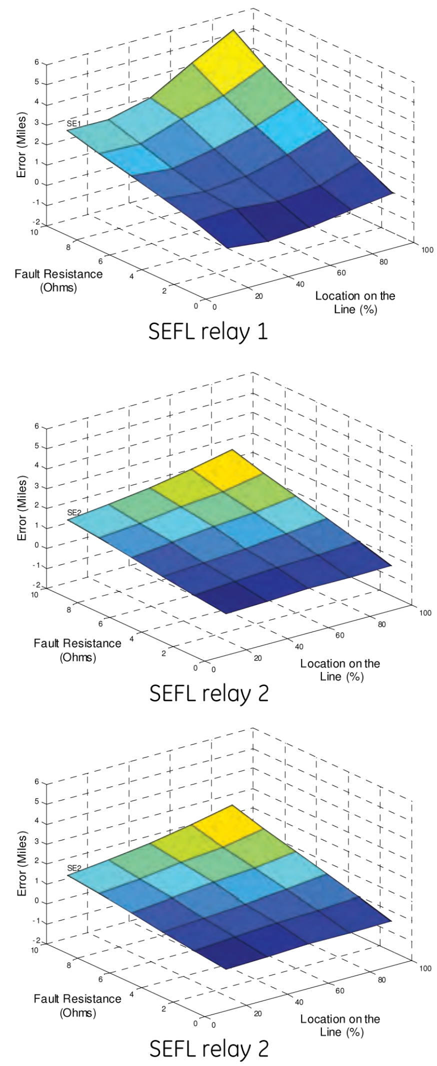


Figure 6.
Error for variable fault resistance for fault along the line, 0.66pu output power

Two different manufacturers single-ended impedance based fault location method relays were used for this testing denoted further as SEFL 1 and SEFL 2, side by side with a multi-ended method MEFL relay.

3.1 Error for variable fault resistance with an export 0.66pu power flow

Figure 6 illustrates the error of 3 fault locators for this test. Parallel line was switched off to eliminate effect of mutual coupling. Error is reported in miles as this is what most important for operations personal dispatched to inspect the line. We can see that for 0 fault resistance all 3 methods give good results. However, the farther the fault and the higher is fault resistance, error is reaching 5 miles for SEFL relay 1, 2.5 miles for SEFL relay 2 and stays almost flat not exceeding 0.5 miles for multiended method relay.

3.2 Error for variable fault resistance with an import 0.66pu power flow

Figure 7 illustrates the error of 3 fault locators for this test.

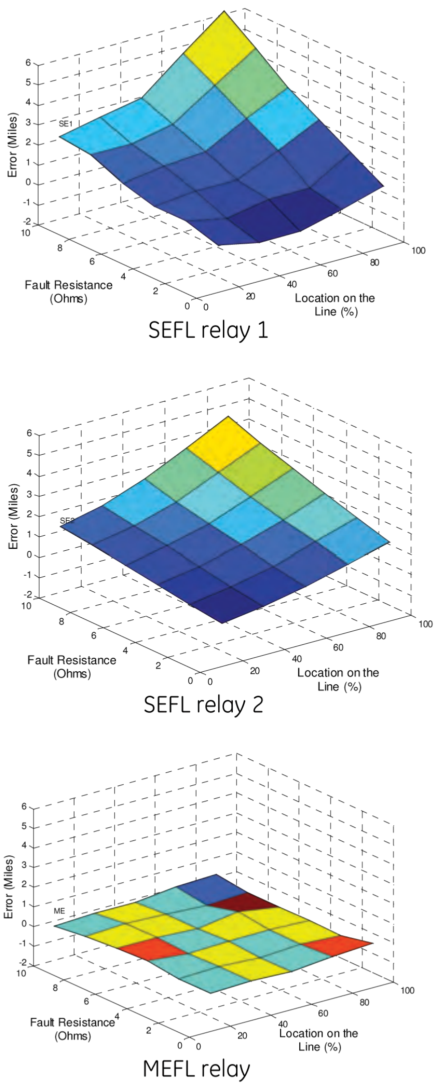


Figure 7.
Error for variable fault resistance for fault along the line, 0.66pu import power

Parallel line was switched off to eliminate effect of mutual coupling. Error is reported in miles as this is what most important for operations personal dispatched to inspect the line. We can see that for 0 fault resistance all 3 methods give good results. However, the farther the fault and the higher is fault resistance, error is reaching 6 miles for SEFL relay 1, 4.5 miles for SEFL relay 2 and stays almost flat not exceeding 0.25 miles for MEFL.

Power import flow is causing noticeable error increase for the single-ended methods, while multi-ended method is not affected.

3.3 Error for different fault types with an export 0.66pu power flow

Figure 8 illustrates the error of 3 fault locators for this test. No mutual coupling and no fault resistance is applied for this fault. Four fault types AG, AB, ABG and ABC were applied. For export power SEFL1 method exhibits extra error of 1.5 miles maximum for multiphase fault while 2 methods give good results.

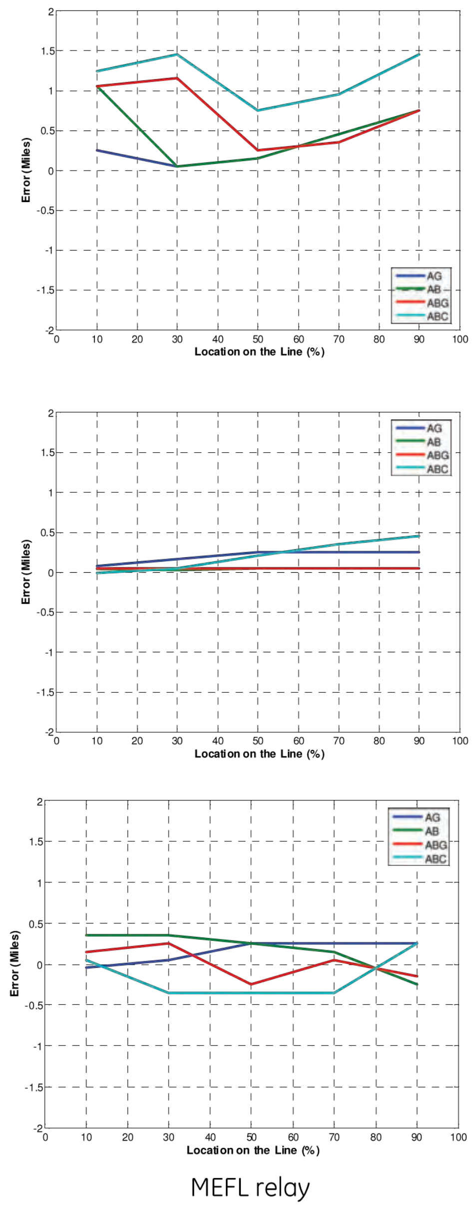
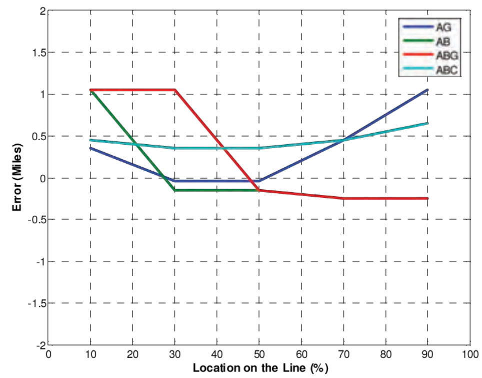


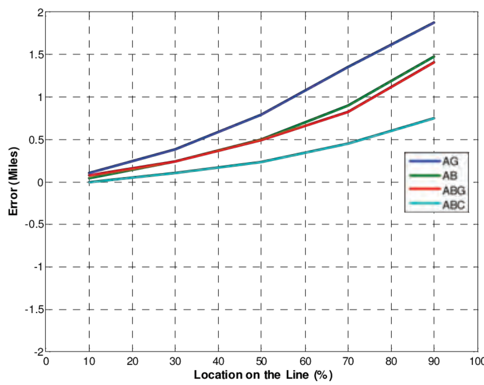
Figure 8.
Error for fault type test for fault along the line, 0.66pu export power

3.4 Error for different fault types with an import 0.66pu power flow

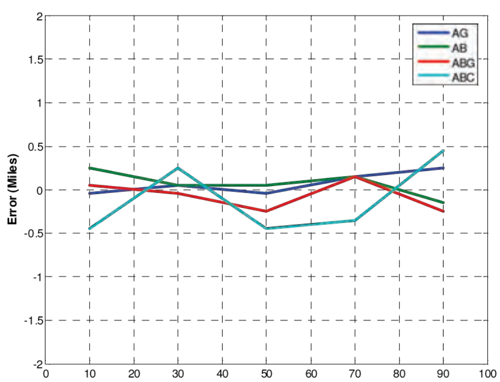
Figure 9 illustrates the error of 3 fault locators for this test. Same conditions, as in 3.3 above, but with importing 0.66pu power. We can see that SEFL1 error is slightly lower but SEFL2 is exhibiting now significant error of up to 2 miles. MEFL result is still within 0.5 miles error.



SEFL relay 1



SEFL relay 2

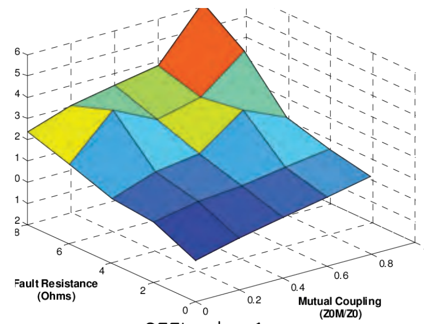


MEFL relay

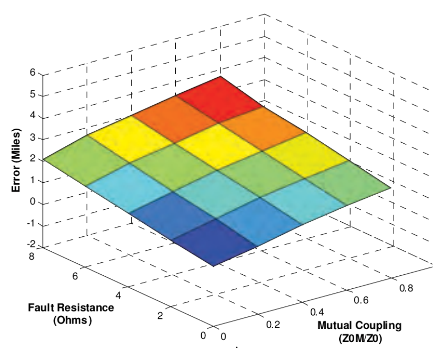
Figure 9.
Error for fault type test for fault along the line, 0.66pu import power

3.5 Error for mutual coupling effect combined with fault resistance with an import 0.66pu power flow

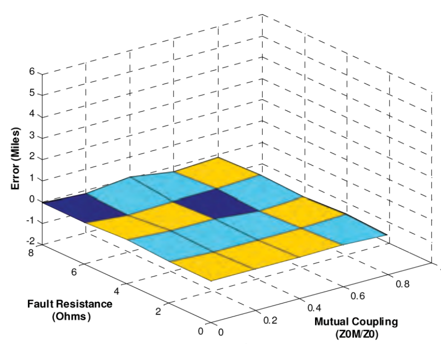
Figure 10 illustrates the error of 3 different fault locators for this test. SLG fault applied always at 50% of line length with a variable value of mutual coupling impedance and variable fault resistance while importing 0.66pu power. Mutual coupling impedance is expressed as a ratio of mutual zero sequence impedance to line self zero sequence impedance Z0M/Z0 from 0 to 0.8 ratio range. Also fault resistance was applied 0 to 8 ohms. We can see that SEFL relay 1 error is reaching 6 miles and SEFL relay 2 is reaching 3.7 miles error for the worst mutual coupling and fault resistance. MEFL relay result is not exceeding 0.5 miles error.



SEFL relay 1



SEFL relay 2



MEFL relay

Figure 10.
Error for mutual coupling effect combined with a fault resistance. Test for a fault 50% on the line, 0.66pu import power

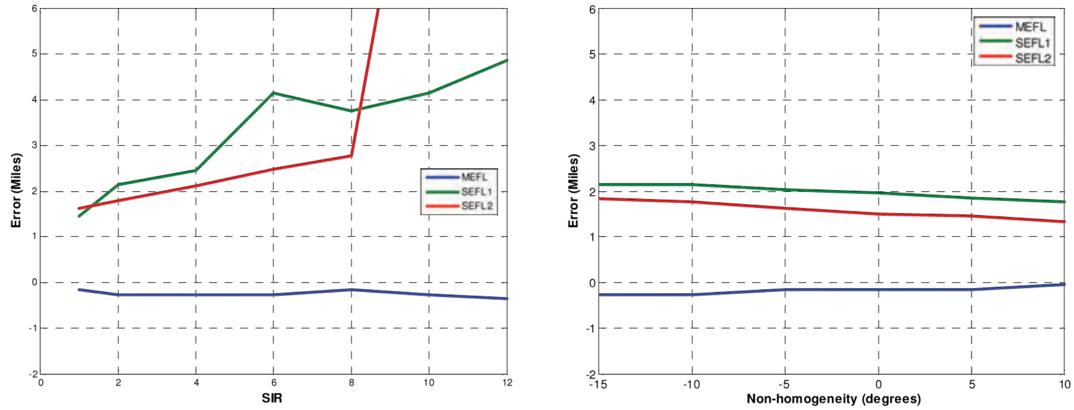


Figure 11.
Error for SIR, system non-homegenuity combined with a fault resistance. Test for a fault 50% on the line, 0.66pu import power

3.6 Error for different fault types with an import 0.66pu power flow

Figure 11 illustrates the error of 3 different fault locators for this test. SLG fault with a fixed 4Ω fault resistance applied always at 50% of line length with a variable value of SIR (source impedance ratio) and angle between local (behind terminal where SEFL relays are connected) and remote sources while importing 0.66pu power. We can see that SEFL relay 1 error is reaching 5 miles for SIR tests while SEFL relay 2 is not capable to calculate fault location for SIR greater than 6. MEFL relay result is not exceeding 0.35 miles error.

System non-homogeneity combined with 4Ω fault resistance is causing error of 2.15 miles for SEFL relay 1 and 1.84 miles for SEFL relay 2 while MEFL relay result is not exceeding 0.25 miles error.

4. Conclusions

This paper presents new multiended method for locating faults on the transmission lines and incorporated into line current differential relay. Advantages of this method are:

- Integrated into line current differential relay via 87L channel, thus no additional cost associated with additional communications channel or additional devices/wiring is involved for fault location purposes.
- Applicable to both two and three terminal applications with realtime fault location and fault resistance reporting at all terminals.
- Immunity to the zero-sequence coupling of adjacent system elements and uncertainty in K0 factor.
- Immunity to a fault type, fault resistance, power flow, system non-homogeneity and weak-strong source applications.
- Increased accuracy comparable with travelling wave fault locators due to synchronized measurements, charge current compensation.

Single-ended methods are impacted by too many factors, which makes them unreliable for operating personal.

It was demonstrated in this paper that new fault location method based on the synchronized line current differential measurements gives significant advantage over single-ended methods in accuracy and gives accuracy comparable with a travelling wave fault locators at no extra cost.

5. References

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041210-v3

Distribution Substation Automation in Smart Grid

Jiyuan Fan, Willem du Toit, Paul Backscheider
GE Digital Energy

Substation Automation (SA) can provide integral functions to the distribution grid automation. As more IED devices are installed to the distribution network, the need for IED management, control, and the corresponding advanced application operation is a growing imperative. Moreover, the Smart Grid applications, such as the Integrated Voltage and Var Control (IVVC), Fault Detection Isolation and Restoration (FDIR) in Distribution Automation (DA), and Advanced Metering Infrastructure (AMI), as well as the Demand Response (DR), offer increased operational functionality for distribution substation and feeders. To realize the full benefits of these new applications, a well designed substation automation architecture will provide scaled approach for adding new automation functions, take use of shared communication infrastructure for feeder automation and AMI, and offer provision for updates to the network model.

Traditionally, SA has been focused on automation functions such as monitoring, controlling, and collecting data inside the substation. This narrow scope allows for effective control of automatic devices located within the substation fence, but does not fully take advantage of automated feeder devices. With the arrival of the Smart Grid comes a new level of expectation for distribution automation. Substation Automation is expected to expand dramatically with increased control of relays, capacitor banks, and voltage regulators along the feeders. New applications are expected to incorporate distributed energy resources, AMI and DR functions. This paper discusses the approach to distribution SA incorporating DA, DR and AMI.

1. Overview of Conventional SA

Conventional SA systems are often viewed separately from the protection and control functions within a substation. Although it is deemed important, the SA infrastructure is often considered in isolation for automation purposes.

In North America the transmission substations have often been automated by the installation of Remote Terminal Units (RTU's), connected to a central EMS /SCADA system, with hard wired I/O in the substation and very little automation applications running in the substation to make it more autonomous during adverse conditions. Distribution substations were rarely connected to a central SCADA system, and were not important enough in the scheme of things to be automated. Even utilities that have done Feeder Automation (FA) as part of their DA system have often neglected to automate the distribution substations. Some utilities have started in the past few years to collect data from protection relays where numerical relays were installed and brought that to the central SCADA for visualization and remote control. In the rest of the world, specifically the IEC world, fully integrated SA systems with several smart applications for increased intelligence in the substations have been developed.

In addition, until very recently, the security based on the User Name and Password in SA and other automation systems has been viewed as quite sufficient. Even the different levels of access that can be achieved with this level of protection have not been fully utilized with sharing of log-in information between engineers, technicians and other network operation people in the order of the day. That situation has changed very drastically in the last couple of years with the NERC-CIP dictating amore rigorous review of security requirements and implementation of a proper physical and Cyber security system for critical assets in the electrical infrastructure.

IN THIS NEW ARCHITECTURE THE SA SYSTEM CAN BE SEEN AS A DECENTRALIZED NERVE CENTER

2. Current SA functions in Smart Grid

Upon further evaluation of effective global smart grid architecture, it is clear that the substation should play an expanded role in the 'smartness' of the grid than in the past. The substation has always been important to the operation of the grid, the SA system now can play the same type of role in the intelligence and become the nerve center of the Smart Grid. For this to happen, standards are urgently required, the looseness that was there in the market in the past with utilities drafting their own standards loosely based on regional (IEEE) or global (IEC) standards has to stop in order to embrace the true benefits. A larger acceptance of global standards will also allow the manufacturers of automation equipment the ability to concentrate on the real issues in providing equipment (IED's, Networking equipment, Software applications) and solutions that will enhance the reliability and improve the efficiency of the electrical network. Adoption of standardization in communication protocol and systems e.g. IEC 61850 will be able to focus the R&D money to find advantages in areas of intelligence of the networks to provide a true Smart Grid. The three main groups of components to achieve this goal are:

1) Smart IED's for sensing, measuring and control of network parameters and equipment
2) Interoperable communications networks to tie the different pieces together
3) Software applications at various levels of the network including the Substation system that can manage the other pieces of the automation system

In this new architecture the SA system can be seen as a decentralized nerve center, enabling the network to be more efficient and more reliable locally while still connected to a higher level of intelligence with a wider perspective, e.g. SCDA/EMS/DMS systems. By keeping the local decision on these aspects local, with substation and feeder automation equipment working in concert, the higher level systems and the communication infrastructure connecting them are freed up to make the higher level determinations for optimization to achieve the eventual goals of improving the network operation, reduce the losses and the impacts that energy transmission and distribution have on the environment.

The SA functions can introduce considerable benefits to the utilities as follows:

Operational

Interoperability, distributed intelligence, integrated communications and systems for greater efficiency and reliability of the equipment, network and energy supply.

Financial

Reduced losses have direct financial benefits. Each KWH that does not have to be generated or transmitted directly reduces the cost of supply. Utilizing the networks more efficiently allow a longer life of equipment and an increased throughput of useful energy, allowing the utility to delay network upgrades. Using the intelligence in the network applications and automation the systems in the substation peak loads can be manipulated and reduced. This reduction has direct benefits for reduced purchase of the more expensive peaking power from less efficient power plants, thereby reducing the utilities cost of operations.

Non-Financial

Non-Financial benefits of the improved substation and feeder automation systems are:

- Reduction of Green House Gas Emissions
- Improved customer satisfaction through higher reliability and reduced outages.
- More efficient utilization of scarce highly skilled resources
- Coordinated training courses and material to increase the pool of resources available to the industry.

3. Applications of DA, DR and AMI in SA

In the extended SA systems, some of the advanced applications in DA, DR and AMI can be incorporated/implemented for enhanced operation performance and capability.

3.1 DA Applications – IVVC, FDIR

Refer to Appendix 1. The net result is that directional relaying is only required where the DG is large enough to trip the devices on an adjacent feeder for faults on that feeder. Tripping devices on the same feeder has no impact on reliability.

DA is not only a key module in distribution grid operation but also a hub connecting other important modules and applications in Smart Grid, such as the Demand Response Management System (DRMS), Advanced Metering Infrastructure (AMI) and Outage Management System (OMS). In general, a DA system comprises of various advanced applications, such as Topology Processor (TP), Distribution Power Flow (DPF), Fault Detection, Isolation and Restoration (FDIR), Integrated Voltage/Var Control (IVVC), Optimal Feeder Reconfiguration (OFR), Distribution Contingency Analysis (DCA), Distribution State Estimation (DSE), Distribution Load Forecasting and Estimation (DLF/DLE), etc. Among them, FDIR and IVVC are the key applications in real time operation and, therefore, are considered as the typical DA applications in the distributed approach while being incorporated into the SA solution.

IVVC is designed for improved distribution system operation efficiency, offering the following basic objectives:

1) Reducing feeder network losses by controlling the feeder capacitor banks' on/off status

AMI DATA FROM THE INDIVIDUAL CUSTOMERS CAN ALSO BE USED TO ENHANCE THE DISTRIBUTION SYSTEM OPERATION AND MANAGEMENT

2) Maintaining healthy voltage profile in normal operation condition

3) Reducing peak load through feeder voltage regulation by controlling the transformer tap positions in substations and voltage regulators in feeder sections.

IVVC optimally coordinates the controls of capacitor banks, voltage regulators and transformer tap positions installed at the feeder circuits and substations. Because the Var output of a capacitor bank is tightly coupled with the voltage in nature, a control action on a capacitor bank for adjusted Var output or on a voltage regulator for a different voltage level can result in significant impacts to each other. Advanced optimization algorithms are necessary for coordinated controls in IVVC for optimal benefits to both healthy voltage profile and feeder efficiency.

On the other hand, FDIR is designed to improve the distribution system reliability by detecting faults occurred at feeder sections based on the remote measurements from the feeder RTUs (i.e., FTUs), quickly isolating the fault by opening the adjacent switches and then restoring the service for the healthy sections affected by the fault. It can reduce the service restoration time from several hours down to 30 seconds or less, considerably improving the distribution system reliability and service quality in terms of the distribution reliability indices of CAIDI, SAIFI SAIDI, etc.

In addition to FDIR and IVVC, the topology processing function of TP plays an important role in supporting the two key applications in real time operation. TP is a background processor that traces the distribution network to track the topology connectivity for internal data processing for the applications and display colorization. TP can also provide service for intelligent alarm processing to suppress unnecessary alarms associated to topology changes.

Another key application in DA is DPF, which is the core function of almost every DA application, especially for FDIR and IVVC. It is designed to solve the three phase unbalanced load flow for either meshed and radial operation scenarios of the distribution network for evaluation or analytic purposes.

Conventionally, SA is defined as the automation system inside the substation fence, completely isolated from the DA functions. In Smart Grid, however, the conventional SA system can be effectively expanded to incorporating DA functions by including the feeder automation functions in the region served by the substation. This expands the service territory of the conventional SA to the area of the feeder circuits in its service territory, effectively combining the SA with the FA functions in a distributed manner.

3.2 DR - Aggregation and Disaggregation

Demand Response is relatively a new function in Smart Grid. It is designed to directly manage the individual customer loads with two-way communication. The potentially dispatchable portion of the individual loads can be aggregated to participate in the system wide economic dispatch for reduced peak demand and minimum energy cost. On the other hand, the dispatched amount of load management can be distributed to the individual loads through disaggregation. The processes of aggregation and disaggregation require an effective coordination with the DA system for optimal grid operation subject to the constraints on voltage and loading limits. The similar process is needed in the recovery stage while returning to the normal operations for the individual customers. The DA functions in SA can also be designed to play the role properly, similar to the centralized DMS system.

3.3 AMI – End of Line Measurements

AMI system is receiving more and more attention in the context of the Smart Grid. In addition to the conventional roles in accounting and customer billing, the AMI data from the individual customers can also be used to enhance the distribution system operation and management, including the historical load profiles for more accurate load forecasting and estimation, as well as the real time information at the end points of feeders to feed DA functions.

5. Approaches to Incorporating DA, DR, AMI in SA

Conventionally, the service territory of a SA is limited to inside the substation fence. While extending the automation scope to include the feeders served by the substation, the service scope of SA is expanded to the distribution feeder circuits. Because the feeders may have open ties to other feeders that are served by other substations, the DA system in a substation has to have the capability to support interoperability with the neighboring substations, becoming the real challenge to the distributed DA systems in SA.

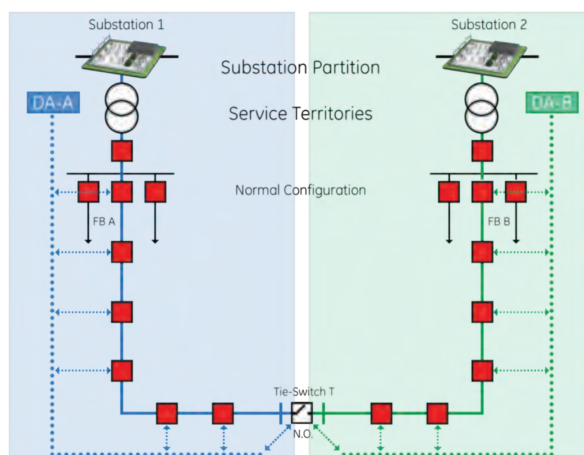

Figure 1.

As described previously, the integration of DA, DR and AMI through data and information exchange can effectively enhance the operation performance of the distribution systems. This advantage can apply to the distributed DA systems too. However, a distributed DA system in a SA can only cover the pre-configured feeders for the substation, a small part of the entire distribution network. The entire distribution network may involve many distributed DA systems in SAs, each covering one or more substations (a logical or virtual substation). In order to implement the automation for a partial or the entire distribution system with the distributed DA systems, an advanced self-coordinating mechanism is required for the individual DA systems to work properly in a well coordinated way through peer-to-peer communications, as schematically shown in Figure 1.

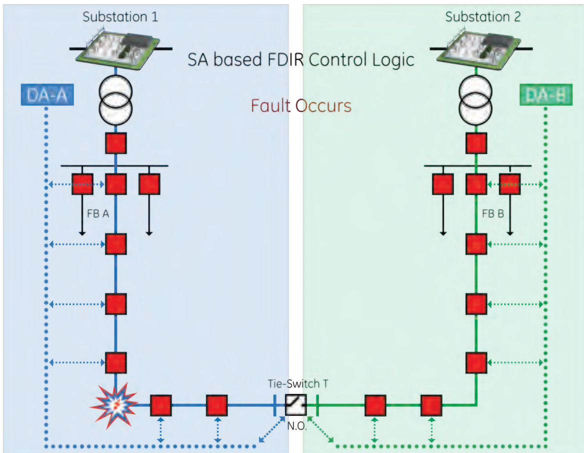

Figure 2a.

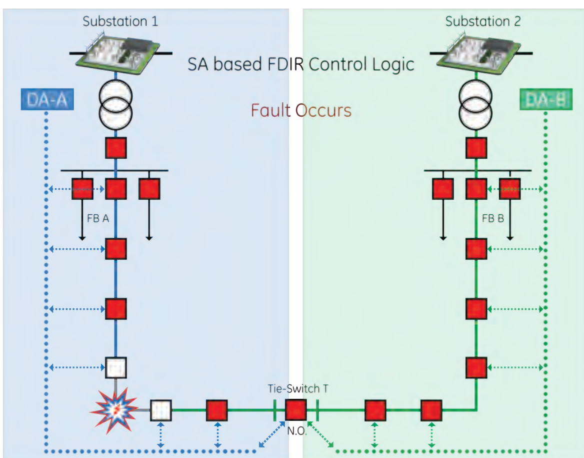

Figure 2b.

The service area of a distributed DA system can include one or more substations. Each area is a part of the connected distribution network that connects to the neighboring areas through the normal open tie-switches. The node at each end of the tie-switch belongs to the area it resides, setting up the boundary of the area. The DA function in each area is fully responsible for the operation of the area. Both parties will exchange or share the boundary information. Figure 2 and Figure 3 illustrate the typical coordination between two areas for FDIR and IVVC operations.

It can be seen from Figure 2 that when a fault is detected by the DA system in Substation A, the FDIR logic isolates the faulted section, restores the service of the upstream sections immediately, then calculates the total load of the downstream sections and checks the loading and voltage limits to figure out the minimum capacity and voltage requirements for substation B to pick up. If substation B is not capable to pick up the load for restoration, alternative approaches will be evaluated, including using multiple sources, transferring loads from one feeder to another in substation B to make more spare capacity, or executing partial restoration to restore service to as much load as possible.

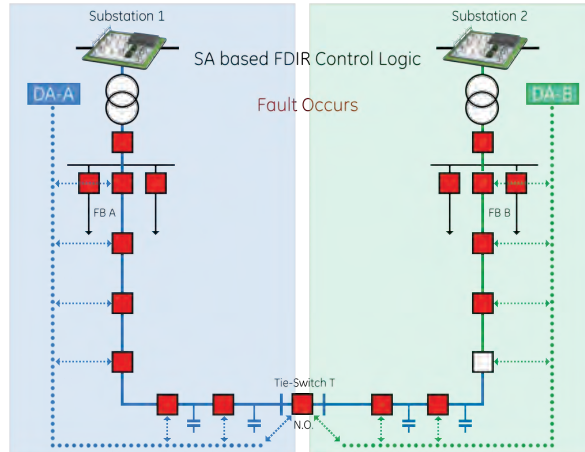

Figure 3.

Figure 3 demonstrates the logic of IVVC operation with the distributed DA system. When a part of the feeder circuit in Substation B is supplied by Substation A through the tie-switch, the IVVC logic of the DA can deal with the case through data exchange between the two substations.

6. Summary

Conventionally, SA has been focused on automation functions such as monitoring, controlling, and collecting data inside the substation. This is a narrow scope to allow for effective control of automatic devices located within the substation fence, but cannot well take advantage of automated feeder devices. In Smart Grid, the SA system in distribution substations can be extended to include the automated feeder devices distribution circuits supplied by the substation. The SA functions in distribution substations can include the key DA functions, such as IVVC and FDIR and can incorporate the AMI and DR data for further enhanced operation performance. An overall review of the conventional SA functions is presented and the extended SA functions in distribution substations are discussed with DA, AMI and DR functions incorporated in Smart Grid operation.

7. Reference

[1] Jiyuan Fan, Xiaoling Zhang, "Feeder Automation within the Scope of Substation", Proceedings of Power Systems Conference and Exposition, 2006 PSCE '06. 2006 IEEE PES, Atlanta, GA, ISBN: 1-4244-0177-1', pp 607 - 612

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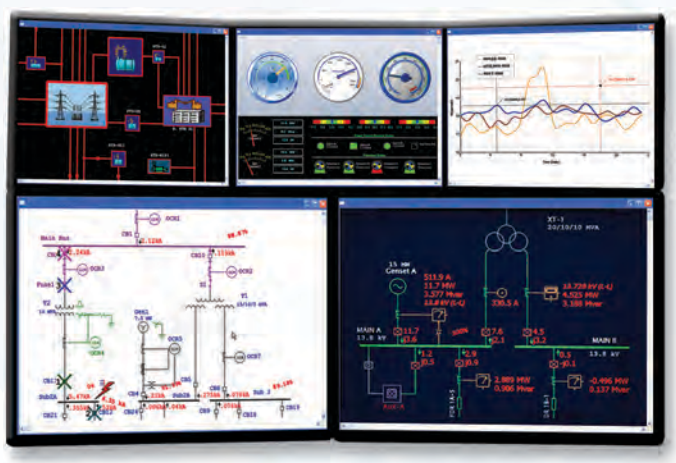

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Distribution System Feeder Overcurrent Protection

General Electric
GET-6450

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1. Introduction

With the increasing loads, voltages and short-circuit duty of distribution substation feeders, distribution overcurrent protection has become more important today than it was even 10 years ago. The ability of the protective equipment to minimize damage when failures do occur and also to minimize service interruption time is demanded not only for economic reasons but also because the general public just expects "reliable" service.

This publication will attempt to review some of the present distribution practices, particularly with regard to relaying, in view of some of these new developments. It is not the purpose of this publication to settle the controversy surrounding some of the problems dealt with, but rather to give the reader a better understanding of distribution overcurrent protection problems and some of the methods being used to solve them.

Among the areas covered will be such things as: cold load pickup, ground-fault detection, tripping methods, current-transformer (CT) connections, line burndown, and coordination between various devices.

2. Relay Fundamentals

2.1 Required Characteristics

The required characteristics necessary for protective equipment to perform its function properly are: sensitivity, selectivity, speed and reliability. This is especially true for relays.

Sensitivity

Sensitivity applies to the ability of the relay to operate reliably under the actual condition that produces the least operating tendency. For example, a time-overcurrent relay must operate under the minimum fault current condition expected. In the normal operation of a power system, generation is switched in and out to give the most economical power generation for different loads which can change at various times of the day and various seasons of the year. The relay on a distribution feeder must be sensitive enough to operate under the condition of minimum generation when a short circuit at a given point to be protected draws a minimum current through the relay. (NOTE: On many distribution systems, the fault-current magnitude does not differ very much for minimum and maximum generation conditions because most of the system impedance is in the transformer and lines rather than the generators themselves.)

Selectivity

Selectivity is the ability of the relay to differentiate between those conditions for which immediate action is required and those for which no action or a time-delayed operation is required. The relays must be able to recognize faults on their own protected equipment and ignore, in certain cases, all faults outside their protective area. It is the purpose of the relay to be selective in the sense that, for a given fault condition, the minimum number of devices operate to isolate the fault and interrupt service to the fewest customers possible. An example of an inherently selective scheme is differential relaying; other types, which operate with time delay for faults outside of the protected apparatus, are said to be relatively selective. If protective devices are of different operating characteristics, it is especially important that selectivity be established over the full range of short-circuit current magnitudes.

Speed

Speed is the ability of the relay to operate in the required time period. Speed is important in clearing a fault since it has a direct bearing on the damage done by the short-circuit current; thus, the ultimate goal of the protective equipment is to disconnect the faulty equipment as quickly as possible.

Reliability

A basic requirement of protective relaying equipment is that it be reliable. Reliability refers to the ability of the relay system to perform correctly. It denotes the certainty of correct operation together with the assurance against incorrect operation from all extraneous causes. The proper application of protective relaying equipment involves the correct choice not only of relaying equipment but also of the associated apparatus. For example, lack of suitable sources of current and voltage for energizing the relay may compromise, if not jeopardize, the protection.

2.2 Characteristics of Overcurrent Relays

The overcurrent relay is the simplest type of protective relay. (See Figure 1.) As the name implies, the relay is designed to operate when more than a predetermined amount of current flows into a particular portion of the power system. There are two basic forms of overcurrent relays: the instantaneous type and the time-delay type.

The instantaneous overcurrent relay is designed to operate with no intentional time delay when the current exceeds the relay setting. Nonetheless, the operating time of this type of relay can vary significantly. It may be as low as 0.016 seconds or as high as 0.1 seconds. The operating characteristic of this relay is illustrated by the instantaneous curve of Figure 2. The time-overcurrent relay (IAC, IFC, or SFC) has an operating characteristic such that its operating time varies inversely as the current flowing in the relay. This type of characteristic is also shown in Figure 2. The diagram shows the three most commonly used time-overcurrent characteristics: inverse, very inverse, and extremely inverse. These curves differ by the rate at which relay operating time decreases as the current increases.

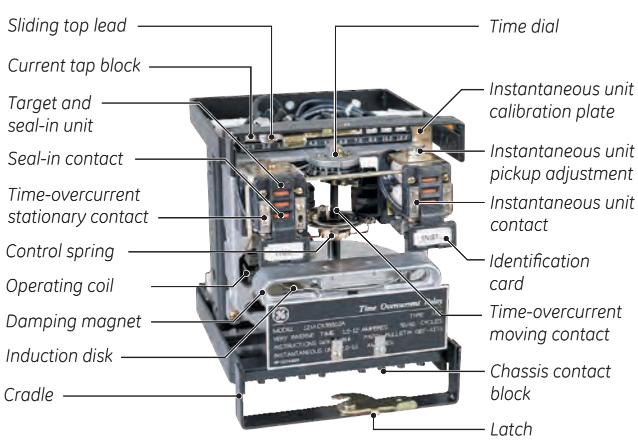
Both types of overcurrent relays are inherently nonselective in that they can detect overcurrent conditions not only in their own protected equipment but also in adjoining equipment. However, in practice, selectivity between overcurrent relays protecting different system elements can be obtained on the basis of sensitivity (pickup) or operating time or a combination of both, depending on the relative time-current characteristics of the particular relays involved. These methods of achieving selectivity will be illustrated later. Directional relays may also be used with overcurrent relays to achieve selectivity.

The application of overcurrent relays is generally more difficult and less permanent than that of any other type of relaying. This is because the operation of overcurrent relays is affected by variations in short-circuit-current magnitude caused by changes in system operation and configuration. Overcurrent relaying in one form or another has been used for relaying of all system components. It is now used primarily on distribution systems where low cost is an important factor.

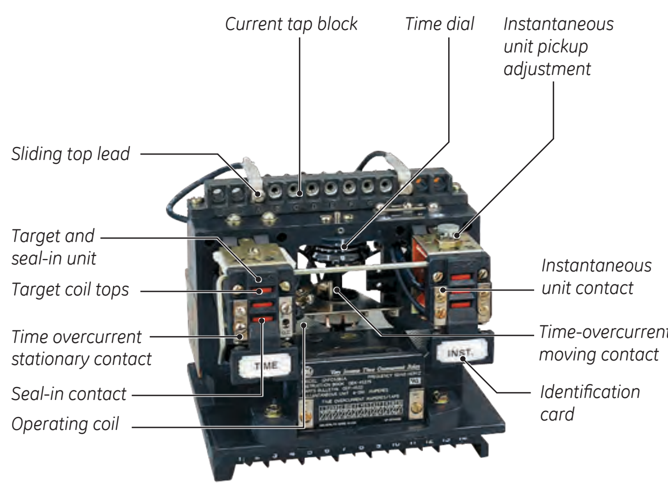
Figure 3 shows a family of inverse-time curves of the widely used IAC relay, which is an induction disc type. The time curves for the new design IFC relay are similar.

A curve is shown for each numerical setting of the time dial scale. Any intermediate curves can be obtained by interpolation since the adjustment is continuous.

It will be noted that the curves shown in Figure 3 are plotted in terms of multiples of pickup value, so that the same curves can be used for any value of pickup. This is possible with induction-type relays where the pickup adjustment is by coil taps, because the ampere-turns at pickup are the same for each tap. Therefore at a given multiple of pickup, the coil ampere-turns, and hence the torque, are the same regardless of the tap used.



Typical IAC relay mechanism with standard hinged armature instantaneous unit withdrawn from case (Model 12IAC53BB10A)



Typical IFC relay mechanism with standard hinged armature instantaneous unit withdrawn from case (model 12IFC53B1A)

Figure 1.
Typical IAC and IFC time-overcurrent relays

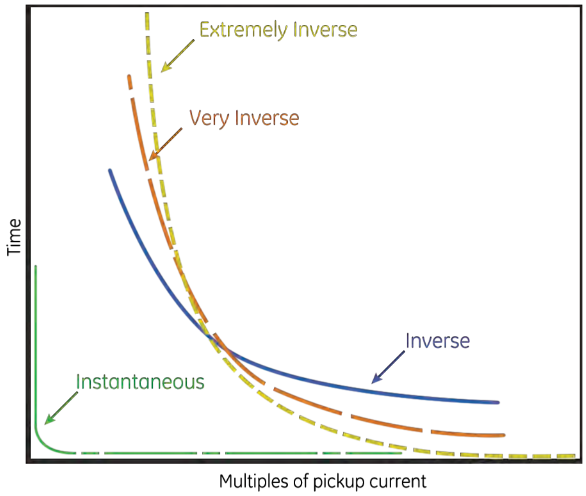


Figure 2.
Time-current characteristics of overcurrent relays

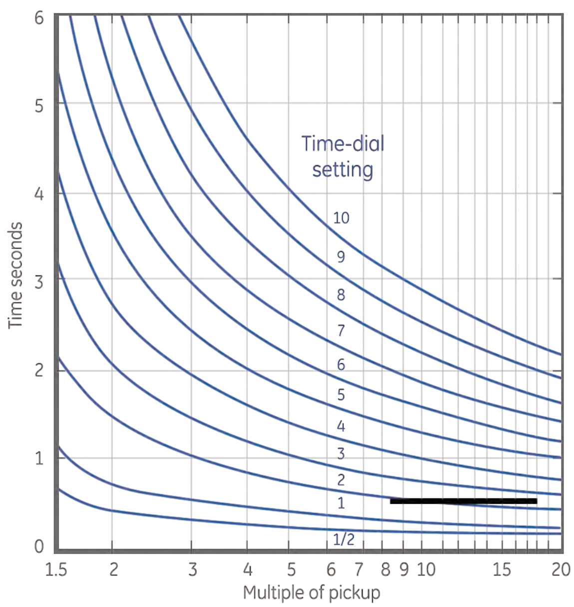


Figure 3.
Inverse time curves

The time-current curves shown in Figure 3 can be used not only to determine how long it will take the relay to close its contacts at a given multiple of pickup and for any time adjustment, but also how far the relay disc will travel toward the contact-closed position within any time interval. For example, assume that the No. 5 time-dial adjustment is used and that the multiple of pickup is 3. It will take the relay 2.45 seconds to close its contacts. We see that in 1.45 seconds, the relay would close its contacts if the No. 3 time-dial adjustment were used. In other words, in 1.45 seconds the disc travels a distance corresponding to 3.0 time-dial divisions, or three fifths of the total distance to close the contacts.

For the most effective use of an inverse-time relay characteristic, its pickup should be chosen so that the relay will be operating on the most inverse part of its time curve over the range of values of current for which the relay must operate. In other words, the minimum value of current for which the relay must operate should be at least 1.5 times pickup, but not very much more.

Figure 4 shows the application of time-overcurrent relays to a radial feeder and the total tripping time characteristics for faults at any location along a circuit. The figure shows the increase in the minimum tripping time as faults occur nearer to the distribution substation - an increase inherent with overcurrent relaying. It also shows the effect of the inverse-time characteristic in reducing this increase. Obviously, the more line sections there are in series, the greater is the tripping time at the source end. It is not at all unusual for this time to be as high as 2 or 3 seconds. This is not a very long time according to some standards, but it would be intolerable if system stability or line burndown were an important consideration.

During light loads, some of the generators are usually shut down. At other times, the system may be split into several parts. In either case, the short-circuit current tends to vary with the amount of generation feeding it. It should be appreciated that a reduction in the magnitude of shortcircuit current raises all of the characteristic curves of Figure 4.

For locations where inverse time-overcurrent relays must be mutually selective, it is generally a good policy to use relays whose time-current curves have the same degree of inverseness. Otherwise, the problem of obtaining selectivity over wide ranges of short-circuit current may be difficult. Instantaneous or undelayed overcurrent relaying is used only for primary relaying to supplement inverse-time relaying and is presently being used by most utilities. It can be used only when the current during short circuit is substantially greater than that under any other possible condition - for example, the momentary current that accompanies the energization of certain system components. The zone of protection of undelayed overcurrent relaying is established

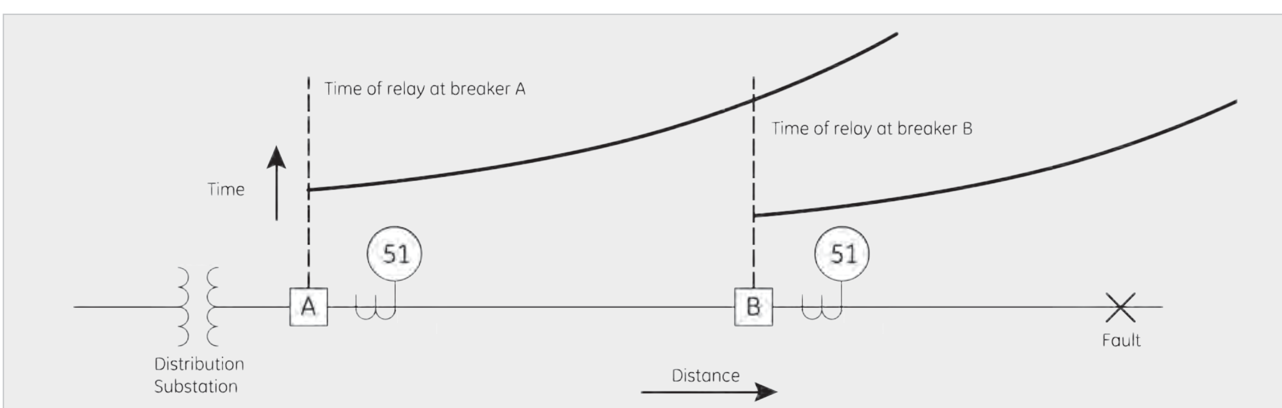


Figure 4.
Operating time of overcurrent relays with inverse time characteristics

entirely by adjustment of sensitivity and is terminated short of the far end of the line. For instance, the instantaneous-overcurrent relay is usually set so that its pickup is 25 percent higher than the maximum current the relay will see for a three-phase fault at the end of the line. With this setting, the instantaneous relay will provide fault protection for about 80 percent of the line section.

Undelayed ("instantaneous") trips can frequently be added to inverse-time relaying and effect a considerable reduction in tripping time. This is shown in Figure 5 where the two sets of characteristics are superimposed. The time saved through the use of the instantaneous relays is shown by the shaded area. A reduction in the magnitude of short-circuit current shortens the distance over which the instantaneous unit operates and may even reduce this distance to zero. However, this fact is usually of no great importance since faster tripping under the maximum short-circuit conditions is the primary objective.

FASTER TRIPPING UNDER THE MAXIMUM SHORT-CIRCUIT CONDITIONS IS THE PRIMARY OBJECTIVE

Instantaneous tripping is feasible only if there is a substantial increase in the magnitude of the short-circuit current as the short circuit is moved from the far end of a line toward the relay location. This increase should be at least two or three times. For this reason, it often happens that instantaneous relaying can be used only on certain lines and not on others.

On systems where the magnitude of short-circuit current flowing through any given relay is dependent mainly upon the location of the fault to the relay, and only slightly or not at all upon the generation in service, faster clearing can usually be obtained with very-inverse-time-overcurrent relays (IAC 53, IFC 53, or SFC 153). Where the shortcircuit current magnitude is dependent largely upon system generating capacity at the time of the fault, better results will be obtained with relays having inverse-time operating characteristics (IAC 51, IFC 51, or SFC 151).

However, towards the ends of primary distribution circuits, fuses are sometimes used instead of relays and breakers. In the region where the transition occurs, it is frequently necessary to use overcurrent relays having extremely inverse characteristics (IAC 77, IFC 77 or SFC 177) to coordinate with the fuse characteristics.

The extremely inverse relay characteristic has also been found helpful, under certain conditions, in permitting a feeder to be returned to service after a prolonged outage.

After such a feeder has been out of service for so long a period that the normal "off" period of all intermittent loads (such as furnaces, refrigerators, pumps, water heaters, etc.) has been exceeded, reclosing the feeder throws all of these loads on at once without the usual diversity. The total inrush current, also referred to as cold-load pickup, may be approximately four times the normal peak-load current. This inrush current decays very slowly and will be approximately 1.5 times normal peak current after as much as three or four seconds. Only an extremely inverse characteristic relay provides selectivity between this inrush and short-circuit current.

2.3 CT Connections

A minimum of three overcurrent relays and a total of three current transformers is required to detect all possible faults in a three-phase AC system. Two of the relays are usually connected in the phase circuits and the third relay is usually connected in the residual circuit of the current transformers as shown in Figure 6. Sensitive ground-fault protection and protection against simultaneous grounds on different parts of the system is provided by this arrangement whether the system is grounded or ungrounded. On ungrounded systems, current flows in the residual relay when grounds occur on different phases on opposite sides of the current transformer location as indicated in Figure 6.

On three-phase, four-wire systems (which represent a large percentage of the new installations), it is not always possible to balance perfectly the single-phase loads among the three phases. The use of a sensitive residual ground overcurrent relay may not be feasible if the relay picks up under normal load conditions. For such systems, the three overcurrent relays are often connected in the phase circuits of the current transformers and the sensitive ground-fault protection sacrificed. An alternative is to use the residual connection of the ground relay in Figure 6 and to set the pickup of the relay above the maximum expected unbalance phase current.

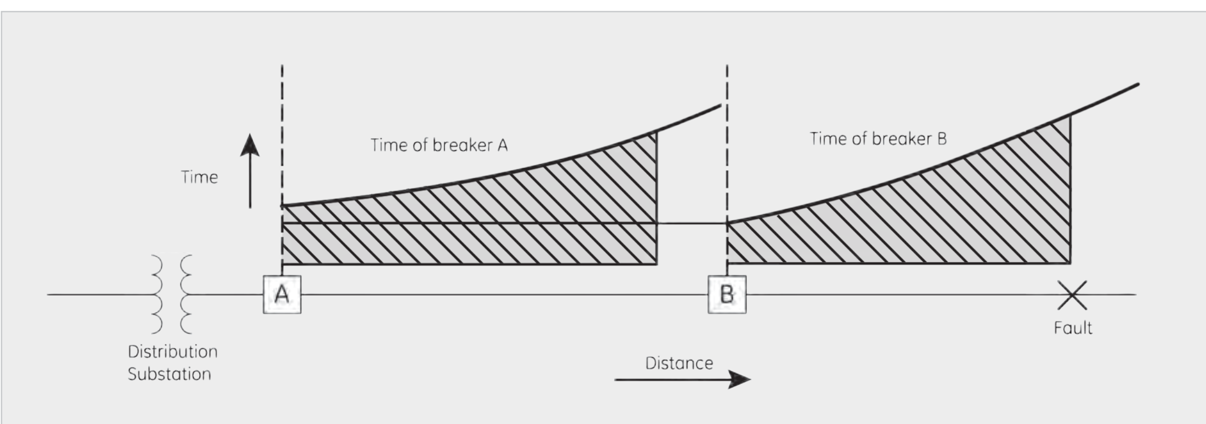


Figure 5.
Reduction in tripping time using instantaneous relaying

It is the practice of some operating companies to block the residual relay to prevent false tripping of the circuit breaker during periods of routine maintenance or when balancing loads on the feeders. This leaves feeders without protection for a line-to-ground fault on the phase without an overcurrent relay, while the residual relay is blocked. It is the usual practice of these companies to request three phase overcurrent relays in addition to one residual-ground relay for these feeders. This gives complete overcurrent protection to the feeders at all times.

2.4 Seal-in (or holdings) Coils and Seal-in Relays

To protect the contacts from damage resulting from a possible inadvertent attempt to interrupt the flow of the circuit-breaker trip-coil current, some relays are provided with a holding mechanism comprising a small coil in series with the contacts. This coil is on a small electromagnet that acts on a small armature on the moving contact assembly to hold the contacts tightly closed once they have established the flow of trip-coil current. This coil is called the "seal-in" or "holding" coil. Other relays use a small auxiliary relay whose contacts by-pass the protective relay contacts and seal the circuit closed while tripping current flows. This seal-in relay may also display the target. In either case, the circuit is arranged so that, once the trip-coil current starts to flow, it can be interrupted only by a circuit breaker auxiliary switch (that is connected in series with the trip-coil circuit) and that opens when the breaker opens. This auxiliary switch is defined as an "a" contact.

The circuits of both alternatives are shown in Figure 7.

2.5 Tripping Methods

The substation circuit-breaker tripping power may be from either a DC or an AC source. A DC tripping source is usually obtained from a tripping battery, but may also be obtained from a station service battery or a charged capacitor. The AC tripping source is obtained from current transformers located in the circuit to be protected.

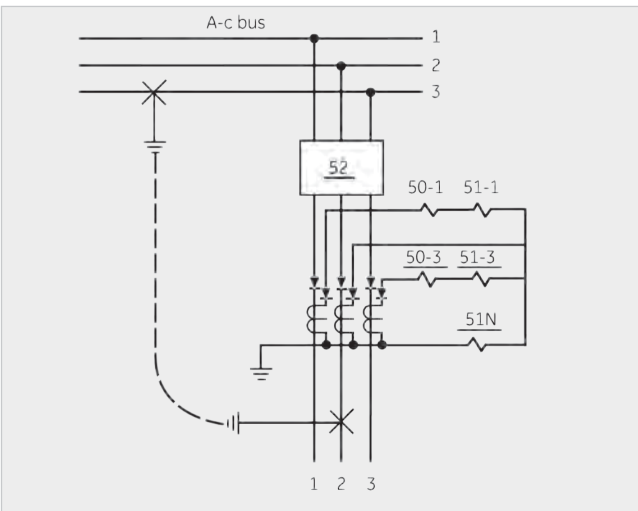


Figure 6.
Elementary diagram of overcurrent relays used for phase- and ground-fault protection of three-phase circuit

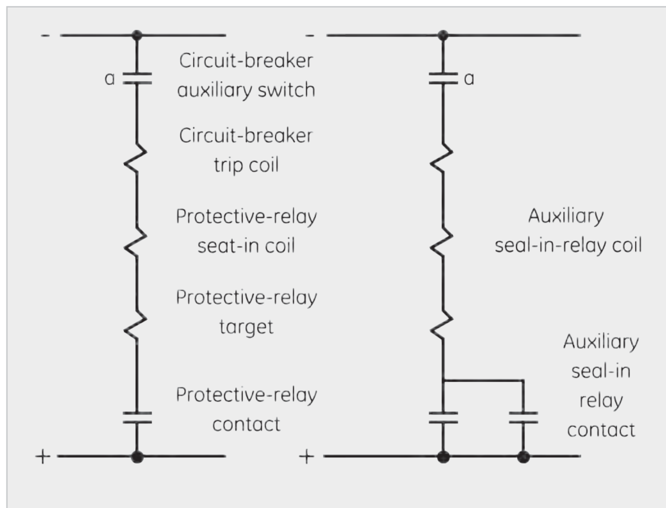


Figure 7.
Alternative contact seal-in methods

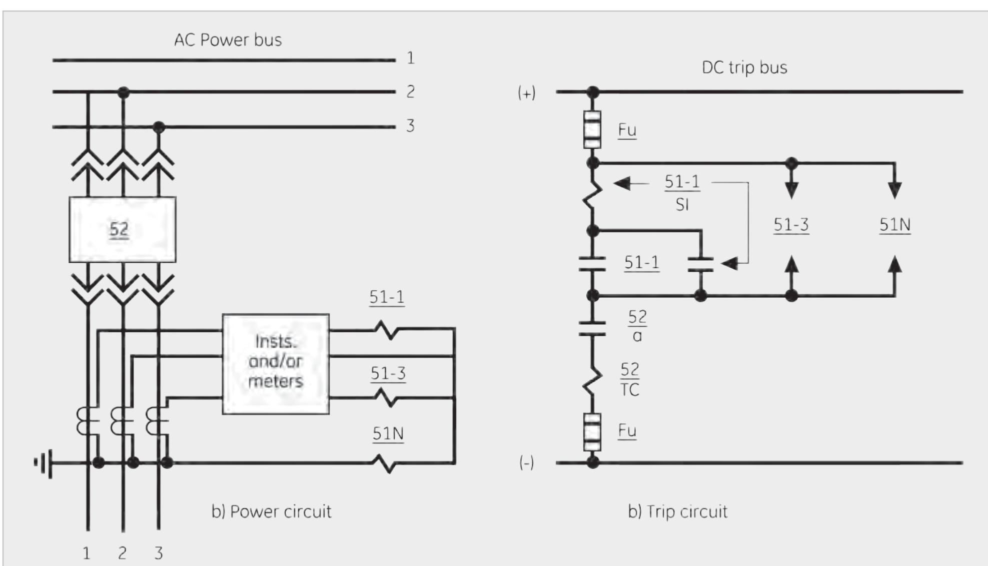


Figure 8.
Elementary diagram of overcurrent relays used with DC battery tripping

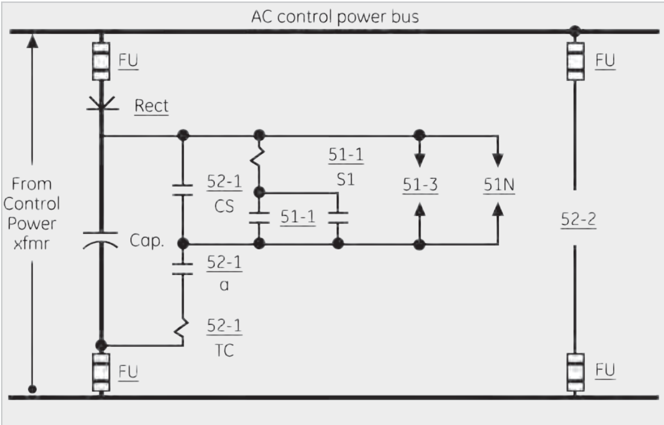


Figure 9.
Elementary diagram of overcurrent relays used with capacitor tripping

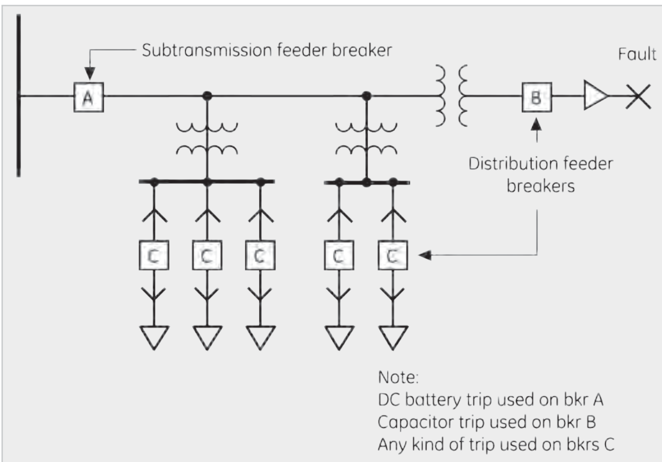


Figure 10.
One-line diagram of feeder breaker using capacitor trip with back-up breaker using battery trip

DC Battery Trip

When properly and adequately maintained, the battery offers the most reliable tripping source. It requires no auxiliary tripping devices, and uses single-contact relays that directly energize a single trip coil in the breaker as shown in Figure 8. A battery trip supply is not affected by the power-circuit voltage and current conditions during time of faults, and therefore is considered the best source for all types of protective relay tripping. An additional advantage is that only one battery is required for each substation location and it may be used for other equipment; e.g., high voltage breaker trip circuits and ground switches.

A tripping battery is usually the most economical source of power for tripping a number of breakers. When only one or two breakers are involved, however, it may be more economical to use AC current or capacitor trip.

Long service can be obtained from batteries when they receive proper maintenance and when they are kept fully charged and the electrolyte is maintained at the proper level and density. When lead-acid batteries are subjected to extremely low ambient temperatures, their output is considerably reduced. In outdoor unit substations, this necessitates larger ampere-hour capacities. For substations in outlying locations where periodic maintenance is difficult, such as many single-circuit substation applications, other types of tripping sources may be more satisfactory.

2.6 Capacitor Trip

An AC potential source is required for charging the capacitors used in the capacitor trip unit. This source may be either a control power transformer or a potential transformer connected where voltage is normally present. A control power transformer is usually used because it is required for AC closing of the circuit breakers. Capacitor trip uses the same standard single-closing contact relays as DC battery trip (see Figure 9). A separate capacitor trip unit is required for each breaker in the substation. The charging time for the unit is approximately 0.04 second and any failure in the charging source for a period longer than 30 seconds renders the trip inoperative. This time must be factored into time-delay settings of relays.

The capacitor trip unit can be used only with low energy tripping devices such as the impact trip device used .on modern breaker-operating mechanisms. Due to the limited amount of energy available from this device, the breaker must be well maintained to assure successful operation. This unit provides tripping potential independent of the magnitude of fault current, which makes it particularly applicable on lightly loaded, high-impedance circuits where AC current trip cannot be used and a battery cannot be justified.

The capacitor trip unit has an additional limitation which is illustrated in Figure 10. Assume that Breaker A has been open long enough for the capacitor trip unit at Breaker B to become de-energized; further assume that a fault has occurred on the feeder of Breaker B during the time that Breaker A was open. Under these conditions, when Breaker A is reclosed, it will re-energize the feeder of Breaker B on a fault. Due to the fault holding the voltage down, the capacitor may not be charged to provide tripping energy upon closing of the protective relay contacts and backup Breaker A would have to clear the fault. The load fed by Breakers C would be without service until Breaker B was manually tripped and Breaker A was reclosed. However, the probability of such a chain of coincident circumstances occurring is relatively small.

2.7 AC Current Trip

If adequate current is always available during fault conditions, the current transformers in the protected circuit provide a reliable source of tripping energy which is obtained directly from the faulted circuit. The tripping may be either instantaneous or time delay in operation; but in all cases, it is applicable only to overcurrent protection.

The trip circuit is more complex than for DC tripping because three trip circuits, complete with individual trip coils and auxiliary devices, are required for each breaker for overcurrent tripping. A potential trip coil is also required for each breaker for normal switching operations. This permits manual tripping of the breaker by means of the breaker control switch. The three trip coils are normally connected in each phase circuit, rather than two phase coils and one residual coil. This is because adequate trip current may not be available under all ground-fault conditions - e.g., when a ground fault occurs at some distance out on the feeder so that there is sufficient neutral impedance to limit the fault current to a value insufficient to cause tripping, or when applied to a system grounded through a neutral impedance. A residual relay, which trips the breaker by means of a potential trip coil, is used to provide ground-fault protection under conditions such as these.

A minimum of three or four amperes CT secondary current is required to energize the three-ampere current-trip coils used for this method of tripping. The use of 0.5- to 4.0-ampere range time-overcurrent relays is not recommended because they are more sensitive than the AC trip coils.

AC current trip may be by means of reactor trip (circuit-closing relays) or auxiliary relay trip (circuit-opening relays). The reactor trip method is usually recommended because of its simplicity and because it uses the more standard type overcurrent relays.

Application Considerations

The choice of the proper source of tripping energy should be based on the application considerations listed here. Any of the foregoing methods are reliable when properly applied; however, each possesses certain advantages and disadvantages. The following general recommendations can be made:

1. Where several breakers are involved and maintenance is good, the storage battery is the most economical. This method also has the added benefit of reliability, simplicity, and ability to be used with all types of protective relays.
2. Where only one or two breakers are used, or maintenance is difficult, one of the other sources could be applied.
    a. AC current trip should be used when adequate current is available.
    b. Capacitor trip could be used where adequate trip current is not available.

3. Feeder Protection

3.1 Cold Load Pickup

Whenever service has been interrupted to a distribution feeder for 20 minutes or more, it may be extremely difficult to re-energize the load without causing protective relays to operate. The reason for this is the flow of abnormally high inrush current resulting from the loss of load diversity. High inrush currents are caused by:

1. magnetizing inrush currents to transformers and motors,

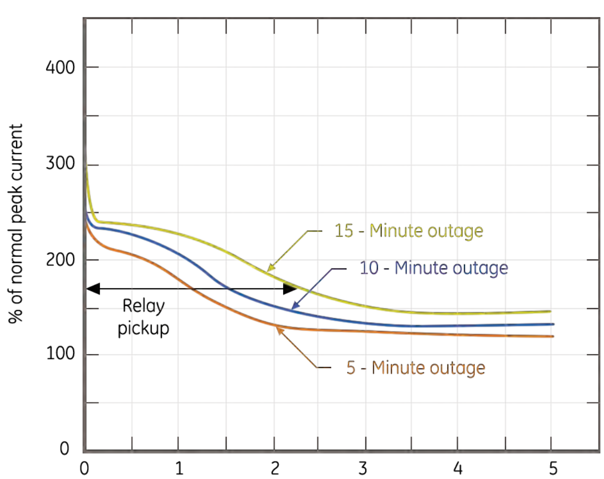


Figure 11.
Five-, ten-, and fifteen-minute outage pickup curves for first five seconds after restoral

2. current to raise the temperatures of lamp filaments and heater elements, and
3. motor-starting current.

Figure 11 shows the inrush current for the first five seconds to a feeder which has been de-energized for 15 minutes. The inrush current, due to magnetizing iron and raising filament and heater elements temperatures, is very high but of such a short duration as to be no problem. However, motor-starting currents may cause the inrush current to remain sufficiently high to initiate operation of protective relays. The inrush current in Figure 11 is above 200 percent for almost two seconds.

The magnitude of the inrush current is closely related to load diversity, but quite difficult to determine accurately because of the variation of load between feeders. If refrigerators and deep freeze units run five minutes out of every 20, then all diversity would be lost on outages exceeding 20 minutes.

A feeder relay setting of 200 to 400 percent of full load is considered reasonable. However, unless precautions are taken, this setting may be too low to prevent relay misoperation on inrush following an outage. Increasing this setting may restrict feeder coverage or prevent a reasonable setting of fuses and relays on the source side of this relay.

A satisfactory solution to this problem is the use of the extremely inverse relay. Figure 12 shows three overcurrent relays which will ride over cold-load inrush. However, the extremely inverse curve is superior in that substantially faster fault-clearing time is achieved at the high-current levels.

This figure, for the purpose of comparison, shows each characteristic with a pickup setting of 200 percent peak load and a five-second time delay at 300-percent peak load to comply with the requirements for re-energizing feeders.

It is evident that the more inverse the characteristic, the more suitable the relay is for feeder short-circuit protection. The relay

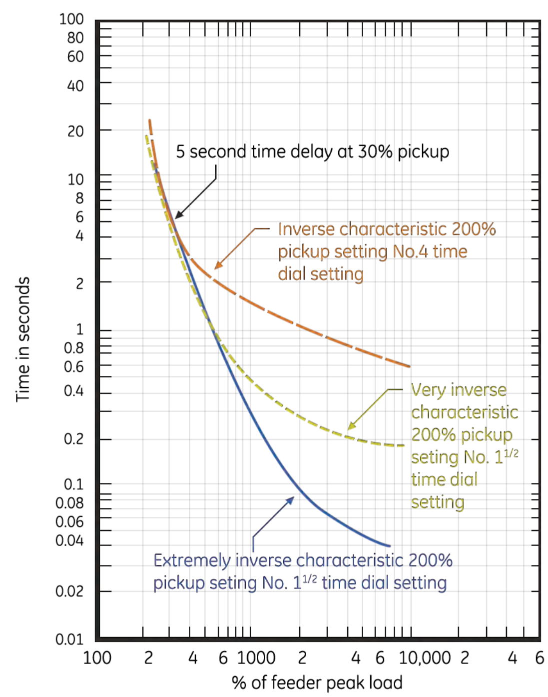


Figure 12.
Comparison of overcurrent relay characteristics

operating time, and hence, the duration of the fault can be appreciably decreased by using a more inverse relay. Comparing the inverse characteristic shows that the extremely inverse characteristic gives from 30-cycles faster operation at high currents to as much as 70-cycles faster at lower currents.

Unfortunately, the extremely inverse relay may not always take care of the problem. As the feeder load grows, the relay pickup must be increased and a point may be reached at which the relay cannot detect all faults. At this time, it may be necessary to either move the fuses or reclosers closer to the substation or use automatic sectionalizing.

3.2 Coordination with the Transformer Primary Use

The practice of fusing the distribution substation is controversial. This is mainly because:

1. the fuse must be replaced every time it blows,
2. the possibility of blowing one fuse and single-phasing three-phase motors exists,
3. the operating time of the fuse must be quite slow so that it coordinates with secondary and feeder breaker relays, and finally
4. the fuse will detect few transformer internal faults since a fault across one-half the winding may be required to cause a fuse to operate.

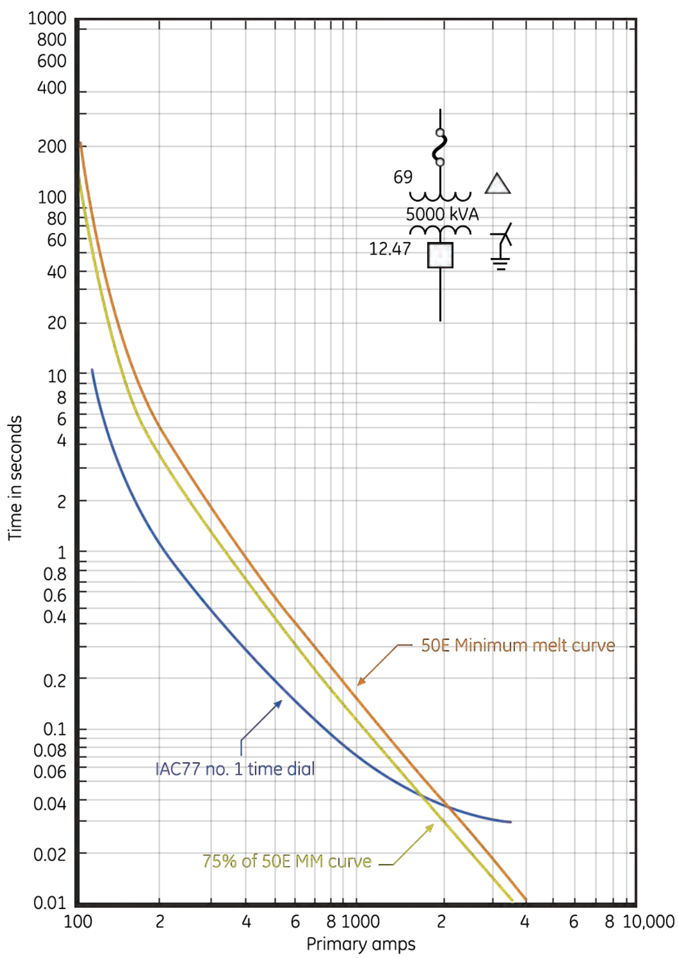


Figure 13.
Plot of a 50E fuse satisfying inrush and emergency criterion

The fuse must be sized so that it will be able to carry 200 percent of transformer full-load current continuously during emergencies and so that transformer inrush current of 12 to 15 times transformer full-load current can be carried for 0.1 seconds.

Coordination with substation transformer primary fuses requires that the total clearing time of the main breaker (relay time plus breaker interrupting time) be less than 75 percent to 90 percent of the minimum melt characteristics of the primary fuses at all values of current up to the maximum available fault current at the secondary bus.

Figure 13 shows a plot of a 50E fuse which satisfies the inrush and emergency criterion mentioned above and another curve of 75 percent of this minimum melt curve.

To prevent the extremely inverse relay from operating on cold-load pickup, its minimum pickup should not be less than 200 to 250 percent of full-load current. In this case. It will be about 90-amperes primary current. As Figure 13 shows, the two devices are coordinated only if the maximum secondary fault current is less than 1500 amperes. If such is not the case, then the size of the fuse must be increased, which in turn limits it's transformer-overload protection capabilities.

3.3 Coordination between Feeder Breakers and the Secondary Breaker

Coordination between feeder breakers and the transformer secondary breaker requires the total clearing time of the feeder breaker (relay time plus breaker interrupting time) to be less than the relay time of the main secondary breaker by a margin which allows 0.1 seconds for electromechanical relay overtravel plus a 0.1 to 0.3-second factor of safety. This margin should be maintained at all values of current through the maximum fault currents available at the secondary bus.

3.4 Fault Selective Feeder Relaying

The reclosing relay recloses its associated feeder breaker at preset intervals after the breaker has been tripped by overcurrent relays. A recent survey indicates that approximately 70 percent of the faults on overhead lines are nonpersistent. Little or no physical damage results if these faults are promptly cleared by the operation of relays and circuit breakers. Reclosing the feeder breaker restores the feeder to service with a minimum of outage time.

If any reclosure of the breaker is successful, the reclosing relay resets to its normal position. However, if the fault is persistent, the reclosing relay recloses the breaker a preset number of times and then goes to the lockout position.

The reclosing relay can provide an immediate initial reclosure plus three timedelay reclosures. The immediate initial reclosure and/or one or more of the time-delay reclosures can be made inoperative as required. The intervals between timedelay reclosures are independently adjustable.

The primary advantage of immediate initial reclosing is that service is restored so quickly for the majority of interruptions that the customer does not realize that service has been interrupted.

The primary objection is that certain industrial customers cannot live with immediate initial reclosing. The operating times of the overcurrent relays at each end of the tie feeder will be different due to unequal fault-current magnitudes. For this reason, the breakers at each end will trip and reclose at different times and the feeder circuit may not be de-energized until both breakers trip again.

The majority of utilities use a three-shot reclosing cycle with either three timedelay reclosures or an immediate initial reclosure followed by two time-delay reclosures. In general, the interval between reclosures is 15 seconds or longer, with the intervals progressively increasing (e.g., a 15-30-45second cycle), giving an over-all time of 90 seconds.

Fault-selective feeder relaying allows the feeder breaker to clear non-persistent faults on the entire feeder, even beyond sectionalizing or branch fuses, without blowing the 10 fuses. In the event of a persistent fault beyond a fuse, the fuse will blow to isolate the faulty section. Operating engineers report reductions of 65 to 85 percent in fuse blowing on non-persistent faults through the use of this method of relaying.

The feeder circuit-breaker overcurrent relays (No. 150/ 151) are provided with inverse-time overcurrent tripping and also instantaneous tripping. When a fault occurs, the instantaneous relay (No. 150) trips the circuit breaker before any of the branch-circuit fuses can blow. When the breaker opens, the instantaneous-trip circuit is automatically opened by the reclosing relay (No. 179) and remains open until the reclosing relay has completely timed out the reset (see Figure 14). If the fault is non-persistent, service to the entire feeder is restored when the breaker recloses, after which the reclosing relay times out to the reset position and the instantaneous trip function is automatically restored.

If the fault is persistent, the circuit breaker recloses on the fault and must trip on the time-delay characteristic since the instantaneous trip is effective only on the first opening. The timedelay trip is adjusted to be slower than the sectionalizing or branch-circuit fuses; consequently, this gives the fuses a chance to blow and isolate the faulted section, leaving the remainder of the feeder in service.

The success of fault-selective feeder relaying depends on proper coordination between the branch-circuit fuses and the feeder-breaker overcurrent relays.

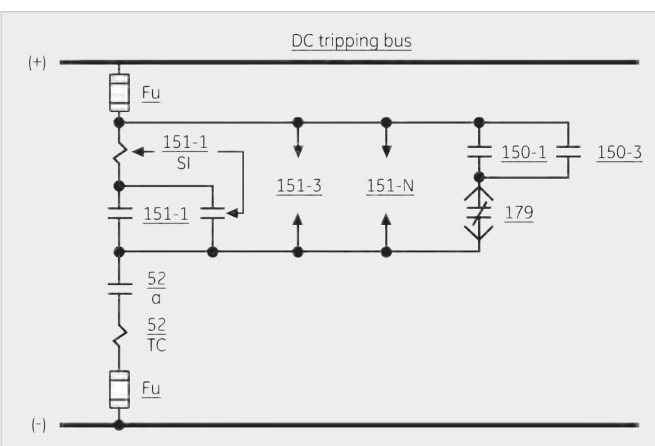


Figure 14.
Elementary diagram of breaker trip circuit showing connections for fault-selective feeder relaying

The feeder breaker, when tripped instantaneously, must clear the fault before the fuse is damaged. Therefore, the breaker-interrupting time plus ,the operating time of the relay-instantaneous attachment must be less than 75 percent of the fuse minimum-melting current at the maximum fault current available at the fuse location. In turn, the fuse must clear the fault before the breaker trips on time delay for subsequent operations. Therefore, the total clearing characteristic of the fuse must lie below the relay characteristic at all values of current up to the maximum current available at the fuse location. The margin between the fuse and relay characteristics must include a safety factor of 0.1 to 0.3 second plus 0.1 second for relay overtravel.

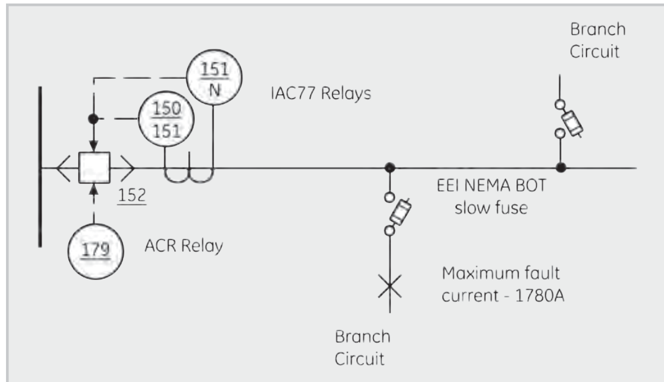


Figure 15.
One-line diagram of typical feeder circuit protected by fault-selective feeder relaying

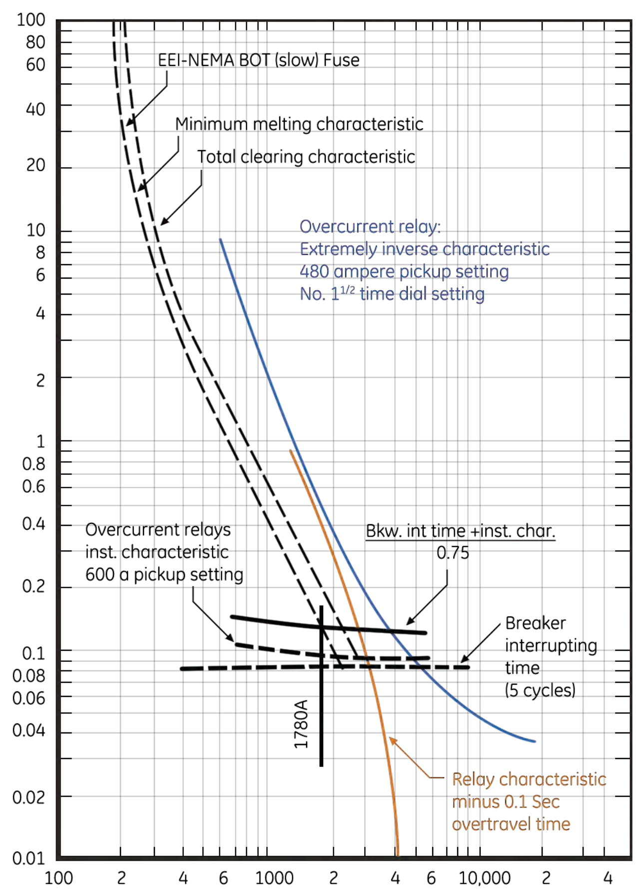


Figure 16.
Coordination of relay and fuse characteristics for fault-selective feeder relay

An example of fault-selective feeder relaying is illustrated in Figures 15 and 16. The one-line diagram of the feeder circuit is shown in Figure 15 and the coordination curves are shown in Figure 16. The overcurrent relay (No. 150/151) has an extremely inverse characteristic (No. 151) with a pickup setting of 480 amperes and 1-1/2 time-dial setting. The instantaneous element (No. 150) has a pickup setting of 600 amperes. The EEI-NEMA 80T (slow) fuse is the largest "slow" fuse which will coordinate with this combination of relay characteristics and settings. At 1780 amperes, the time delay of the relay-instantaneous element, plus the breaker-interrupting time, are just equal to 75 percent of the fuse minimum-melting time. At this same current magnitude, the fuse total clearing time is less than the relay time-delay characteristic by a suitable margin. Therefore, the fuse and relay coordinate for current magnitudes of 1780 amperes or less.

AN IMPORTANT FACTOR IN OBTAINING THIS SELECTIVITY IS THE RESET TIME OF THE OVERCURRENT RELAYS

For certain applications, the maximum available fault current will exceed the maximum current which will permit coordination. There are two reasons for this:

1. the maximum current for coordination is lower for lower-rated fuses and is also lower for Type K (fast) fuses, and
2. fault currents may be quite high at fuse locations comparatively near the substation.

Of course, if the branch circuit is single phase, it is only necessary to consider the maximum line-to-line or line-to-ground fault current, both of which are less than the maximum three-phase fault current. For such applications, coordination can be relied upon only when there is sufficient additional impedance to limit the fault current to the maximum current which will permit coordination. This additional impedance can either be in the fault itself or in the branch circuit between the fuse and the fault location. Therefore, while coordination will be questionable for faults near the fuse, there will be complete coordination for faults which occur father out on the branch circuit.

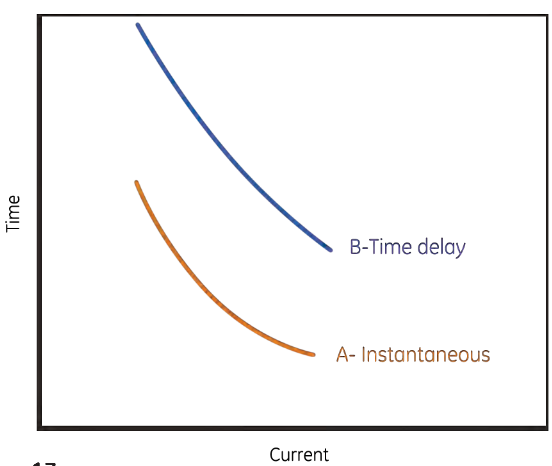


Figure 17.
Tripping characteristic for conventional automatic circuit recloser

3.5 Coordination of Feeder Relays and Reclosers

If a permanent fault occurs anywhere on the system beyond a feeder, the recloser device will operate once, twice, or three times instantaneously (depending upon adjustment) in an attempt to clear the fault. However, since a permanent fault will still be on the line at the end of these instantaneous operations, it must be cleared away by some other means. For this reason, the recloser is provided with one-, two-, or three-time delay operations (depending upon adjustment). These additional operations are purposely slower to provide coordination with fuses or allow the fault to "self clear". After the fourth opening, if the fault is still on the line, the recloser will lock open.

Figure 17 represents the instantaneous-and time-delay characteristics of a conventional automatic circuit recloser.

At substations where the available short-circuit current at the distribution feeder bus is 250 MVA or more, the feeder circuits are usually provided with circuit breakers and extremely inverse-time overcurrent relays. The relays of each feeder should be adjusted so that they can protect the circuit to a point beyond the first recloser in the main feeder but with enough time delay to be selective with the recloser during any or all of the operations within the complete recloser cycle.

An important factor in obtaining this selectivity is the reset time of the overcurrent relays. If, having started to operate when a fault occurs beyond the recloser, an overcurrent relay does not have time to completely reset after the recloser trips and before it recloses (an interval of approximately one second), the relay may "inch" its way toward tripping during successive recloser operations. Thus it can be seen that it is not sufficient merely to make the relay time only slightly longer than the recloser time.

It is a good "rule of thumb" that there will be a possible lack of selectivity if the operating time of the relay at any current is less than twice the time-delay characteristic of the recloser. The basis of this rule, and the method of calculating the selectivity, will become evident by considering an example.

First, it should be known how to use available data for calculating the relay response under conditions of possibly incomplete resetting. The angular velocity of the rotor of an inverse-time relay for a given multiple of pickup current is substantially constant throughout the travel from the reset (i.e., completely open) position to the closed position where the contacts close. Therefore, if it is known (from the time-current curves) how long it takes a relay to close its contacts at a given multiple of pickup and with a given time-dial adjustment, it can be estimated what portion of the total travel toward the contact-closed position the rotor will move in any given time. Similarly, the resetting velocity of the relay rotor is substantially constant throughout its travel. If the re-set time from the contact-closed position is known for any given time-delay adjustment, the reset time for any portion of the total travel can be determined. The re-set time for the longest travel (when the longest time delay adjustment is used) is generally given for each type of relay. The re-set time for the number 10 time-dial setting is approximately six seconds for an inverse Type IAC relay, and approximately 60 seconds for either a very inverse or any extremely inverse Type IAC relay.

The foregoing information may be applied to an example by referring to Figure 18. Curves A and 8 are the upper curves of the band of variation for the instantaneous and timedelay characteristics of a 35-ampere recloser. Curve C is the time-current curve of the very inverse Type IAC relay set on the number 1.O time-dial adjustment and 4-ampere tap (160-ampere primary with 200/5 current transformers). Assume that it is desired to check the selectivity for a fault current of 500 amperes. It is assumed that the fault will persist through all of the reclosures. To be selective, the IAC relay must not trip its breaker for a fault beyond the recloser.

The operating times of the relay and recloser for this example are:

Recloser:

Instantaneous	- 0.036 second
Time delay	- 0.25

Relay:

Pickup	- 0.65 second
Reset	- (1.0/10)(60) = 6.0 second

The percent of total travel of the IAC relay during the various recloser operations is as follows, where plus means travel in the contact-closing direction and minus means travel in the re-set direction:

Recloser Operation		Percent of Total Relay Travel
First instantaneous trip (0.036/0.65)	×	(100) = 5.5
Open for one second (1/6)	×	(100) = -16.7

It is apparent from this that the IAC relay will completely reset while the recloser is open following each instantaneous opening.

Recloser Operation	Percent of Total Relay Travel
First time-delay trip	(0.25/0.65) × (100) = +38.5
Open for one second	(1/6) × (100) = -16.7
Second time-delay trip	(0.25/0.65) × (100) = +38.5

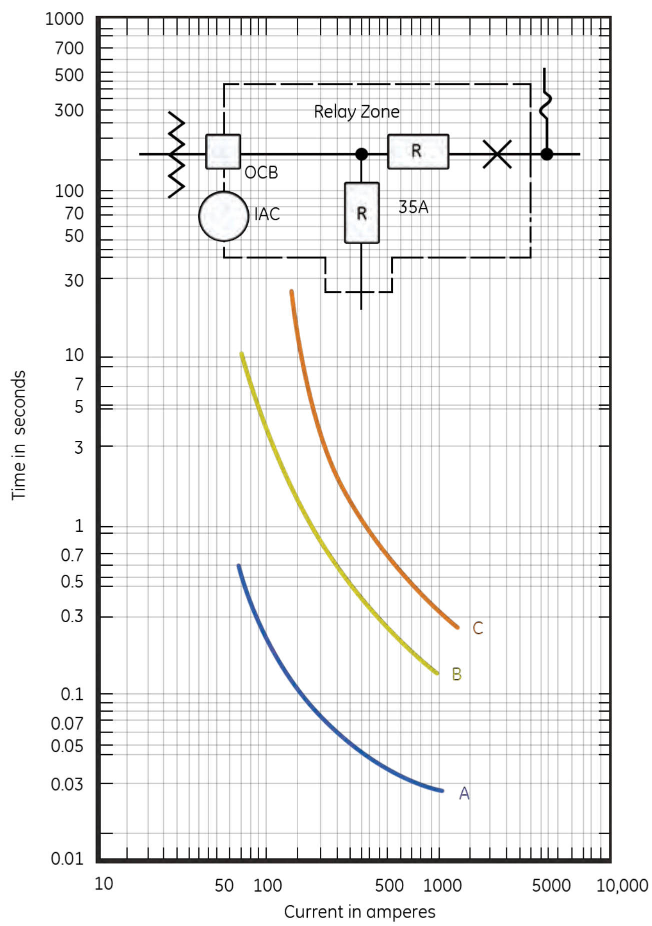
From this analysis, it appears that the relay will have a net travel of 60.3 percent of the total travel toward the contact-closed position.

From the foregoing, it is seen that the relay travel lacks approximately 40 percent (or 0.4 × 0.65 = 0.24 second) of that necessary for the relay to close its contacts and trip its breaker. On the basis of these figures, the IAC will be selective. A 0.15- to 0.2-second margin is generally considered desirable to guard against variations from published characteristics, errors in reading curves, etc. (The static overcurrent relay Type SFC, overcomes some of these problems since the overtravel of such a relay is about 0.01 seconds and the reset time is 0.1 seconds or less.)

If the automatic circuit reclosers are used at the substation as feeder breakers, it is necessary to select the proper size to meet the following conditions:

1 The interrupting capacity of the recloser should be greater than the maximum calculated fault current available on the bus.

2. The load-current rating (coil rating) of the recloser should be greater than the peak-load current of the circuit. It is recommended that the coil rating of the recloser be of sufficient size to allow for normal load growth and be relatively free from unnecessary tripping due to inrush current following a prolonged outage. The margin between peak load on the circuit and the recloser rating is usually about 30 percent.



A. Time-current characteristic of one instantaneous recloser opening

B. Time-current characteristic of one extended timedelay recloser opening

C. Time-current characteristic of the IAC relay

Figure 18.
Relay-recloser coordination

3. The minimum pickup current of the recloser is two times (2X) its coil rating. This determines its zone of protection as established by the minimum calculated fault current in the circuit. The minimum pickup rating should reach beyond the first-line recloser sectionalizing point, i.e., overlapping protection must be provided between the station recloser and the first-line recloser. If overlapping protection cannot be obtained when satisfying requirement (l), it will be necessary to relocate the first-line recloser to have it fall within the station recloser protective zone.

3.6 Coordination of Reclosers and Fuses

Figure 19 shows the time-current characteristic curves of the automatic circuit recloser. On these curves, the timecurrent characteristics of a fuse C is superimposed. It will be noted that fuse curve C is made up of two parts: the upper portion of the curve (low-current range) representing the total clearing time curve, and the lower portion (highcurrent range) representing the melting curve for the fuse. The intersection points of the fuse curves with recloser curves A and B, define the limits between which coordination will be expected. It is necessary; however, that the characteristic curves of both recloser and fuse be shifted or modified to take into account alternate heating and cooling of the fusible element as the recloser goes through its sequence of operations.

Figure 20 shows what occurs when the current flowing through the fuse link is interrupted periodically. The oscillogram shows typical recloser operation. The first time the recloser opens and closes due to fault or overload, the action is instantaneous, requiring only two cycles. The second action is also two cycles, while the third action is delayed to 20 cycles, as is the fourth. Then the recloser locks itself open.

For example, if the fuse link is to be protected for two instantaneous openings, it is necessary to compare the heat input to the fuse during these two instantaneous recloser openings. The recloser-fuse coordination must be such that during instantaneous operation the fuse link is not damaged thermally.

Curve A', Figure 21, is the sum of two instantaneous openings (A) and is compared with the fuse damage curve which is 75 percent of the melting-time curve of the fuse.

This will establish the high-current limit of satisfactory coordination indicated by intersection point b'. To establish the low-current limit of successful coordination, the total heat input to the fuse represented by curve B' (which is equal to the sum of two instantaneous (A) plus two time-delay (B) openings) is compared with the total clearingtime curve of the fuse. The point of intersection is indicated by a'.

For example, to establish how coordination is achieved between the limits of a' and b', refer to Figure 21. It is assumed that the fuse beyond the recloser must be protected against blowing or being damaged during two instantaneous operations of the recloser in the event of a transient fault at X. If the maximum calculated short-circuit current at the fuse location does not exceed the magnitude of current indicated by b', the fuse will be protected

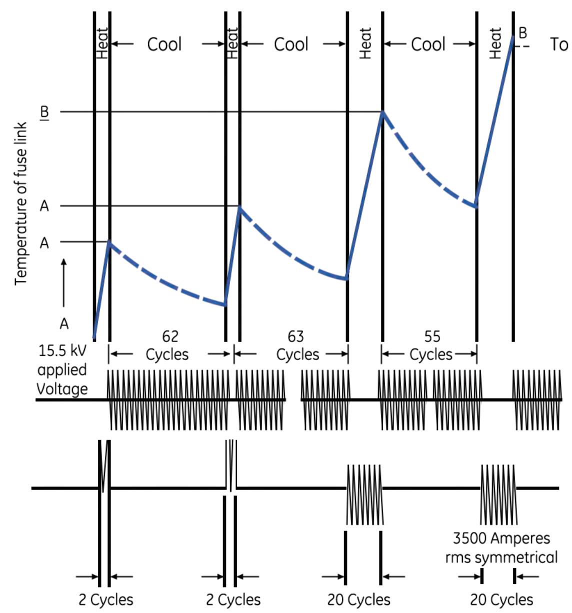


Figure 20.
Fuse link heating and cooling

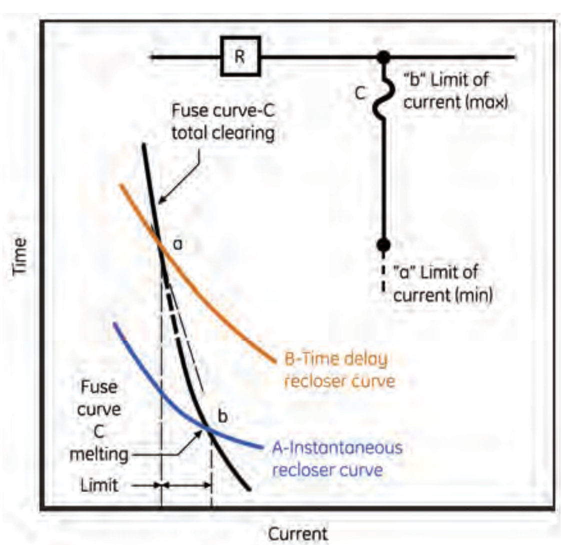


Figure 19.
Time-current characteristic curves of recloser superimposed on fuse curve C

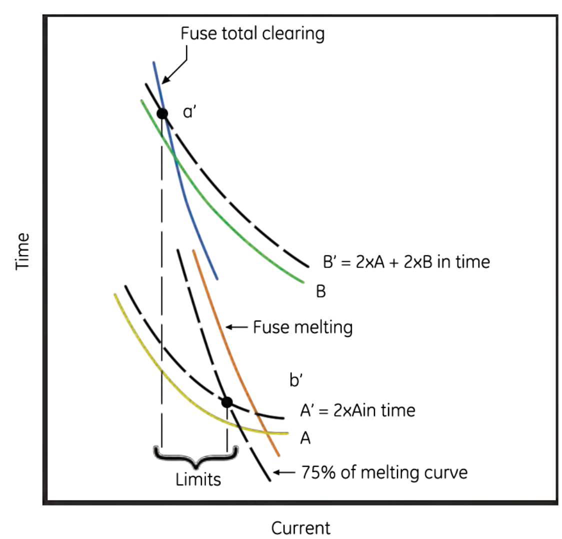


Figure 21.
Recloser- fuse coordination (fuse operated for heating and cooling)

during transient faults. For any magnitude of short-circuit current less than b', but greater than a' (see Figure 21), the recloser will trip on its instantaneous characteristic once or twice to clear the fault before the fuse-melting characteristic is approached. However, if the fault is permanent, the fuse should blow before the recloser locks out. If the minimum (line-to-ground) calculated short-circuit current available at the end of the branch is greater than the current indicated by a', the fuse will blow (see Figure 21) before the time-delay characteristic of the recloser is approached.

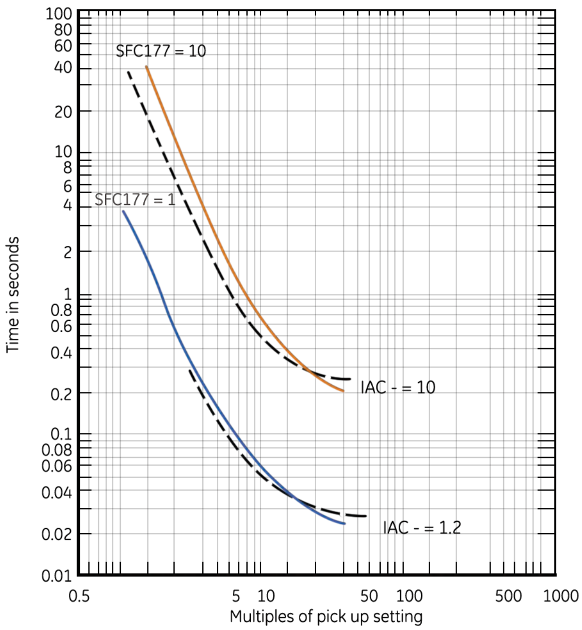


Figure 22.
Comparison of extremely inverse time-current characteristics of SFC 177 and IAC 77 relays

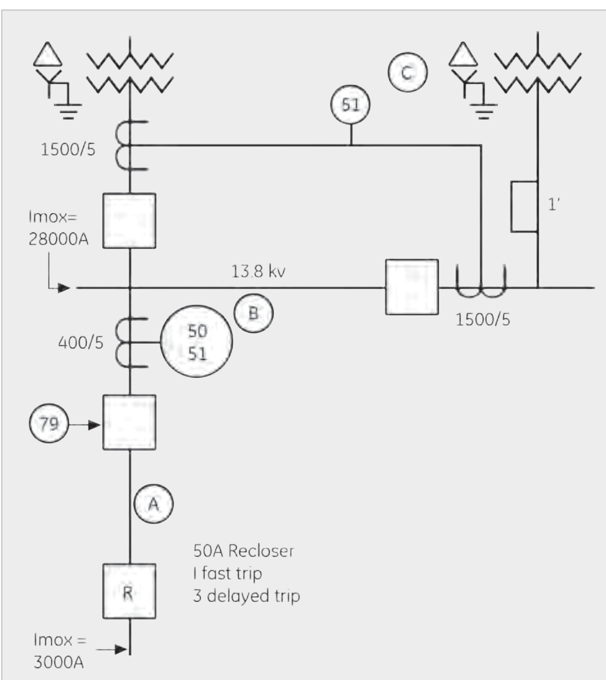


Figure 23.
Sample system for recloser-relay coordination illustration

3.7 Static Overcurrent Relays (SFC)

Since static over-current relays (SFC) are electronic analogs of conventional electromechanical relays, it is to be expected that the general principles of application covered earlier will still be pertinent. In general, this is true although there are several important differences which come about because the relay employs solid-state electronic operating principles.

In designing the SFC static overcurrent relay, it was recognized that the time-current characteristic could be built with any desired shape. Furthermore, the manner in which the relay operates ensures that the curve shape will remain essentially unchanged regardless of the actual time dial setting. Thus, a critical decision in relay design was to choose a curve shape. It was judged to be important that the relay be designed so that it could easily be integrated into an existing system. This consideration essentially ruled out the use of totally new curve shapes and lead to a decision to duplicate the three basic time-current characteristics of IAC relays: inverse, very inverse, and extremely inverse. Because experience indicates that the lower timedial settings on IAC relays tend to be used somewhat more frequently than the upper time-dial settings, the actual curves chosen for the new SFC relays were selected to match the lower time-dial curve from IAC relays. However, it should be noted that there is no reason to insist that this match be exact. IAC curves were selected as design goals for convenience only; other curves could have been selected as well.

Figure 22 illustrates the correlation between the curves of IAC (solid lines) and SFC (dashed lines) relays in the inverse, very inverse, and extremely inverse characteristics, respectively. A brief comparison of the curves reveals that the characteristics match very closely for lower time-dial settings, but at higher time dials there are noticeable differences both in time and shape. Therefore, it is very important to recognize that the SFC is functionally equivalent to an IAC of corresponding characteristic and that it may be used to advantage as a backup relay for an electromechanical relay or vice versa; however, it is equally important to recognize that a static SFC relay cannot be substituted for an electromechanical relay in an existing application without first determining an appropriate setting for the SFC in that application. Specifically, this means that equivalent settings for IAC and SFC relays will have identical pickup taps, but the time-dial calibration will be different.

Two specific areas where the electromechanical (IAC and IFC) and static (SFC) relay differ are overtravel and reset.

Overtravel in electromechanical relays is a function of the design of the relay, its pickup and time-dial settings, and the magnitude of fault current. It is not an easy number to determine precisely and traditionally an estimate of 0.1 seconds has proved to be sufficiently long. Overtravel in the SFC static overcurrent relay is 0.01 seconds or less. Based upon these numbers, the following minimum coordination margins can be determined:

	IAC	IFC	SFC
Breaker Time	0.0833	0.0833	0.0833
Overtravel	0.1000	0.1000	0.0100
Safety Factor	0.1000	0.1000	0.1000
	0.2833	**0.2833**	**0.1933**

For practical purposes, these numbers can be given as 0.3 seconds for IAC and IFC electromechanical relays and 0.2 seconds for SFC static relays.

Reset time is the time required for the relay to return to its fully reset position after the recloser has interrupted the short circuit. For conventional electromechanical relays, reset time is very long. The IAC 77 takes a full minute to return to the reset position from the contact-closed position when set on the number 10 time dial.

However, the static SFC relay resets in 0.1 seconds or less regardless of the characteristic or time dial used, which is faster than the reclosing time of any distribution recloser or breaker available today. This difference is best illustrated by an example.

Consider the system of Figure 23. The pole-type recloser is set for one fast and three time-delay trips and its reclose time is two seconds. In coordinating relays and reclosers, a margin of 0.15 to 0.2 seconds is normally considered the minimum safe tolerance. In this instance, in anticipation of possible problems with reset, a longer margin (0.3 seconds) was selected as a point of departure. The feeder breaker is equipped with an instantaneous overcurrent relay set at 5362 amperes (primary) for an equivalent coverage of approximately 1.5 miles of 13.8-kV circuit. The instantaneous unit is blocked after the first trip and the reclosing relay on the feeder breaker is adjusted for a CO+5+CO+5+CO+5+CO operating cycles. The backup relay at the substation is shown as a partial differential (summation overcurrent) connection, although this is not significant to the example.

Figure 24 shows the time-current curves for this system using electromechanical IAC 77 relays. The trial setting for the feeder relay is shown as the dashed curve B and a 320-ampere pickup and number 7 time dial. With this time dial, the reset time of the IAC 77 is about 42 seconds. It is significant to observe that even though the curves show an apparent margin of 0.3 seconds, the true margin between the IAC 77 and the recloser is only 0.103 seconds as determined in Table 1. Thus the number 8 time dial is required as noted by the solid curve B in Figure 24. Similarly, the apparent margin for the backup relay is not sufficient because of reclosing by the feeder breaker, and a higher time dial must be used to assure a minimum of 0.3- second margin between relays.

In Figure 25 the system curves are again drawn, but this time for static SFC 177 relays on the feeder breaker and as the backup relay, The reset time of the SFC (0.1 seconds) is faster than the reclosing delay of either the automatic recloser or the reclosing feeder breaker. Therefore, no consideration at all need be given to "notching" and the relay settings can be determined by the time-current curves alone. Also, because overtravel is negligible, the margin between the backup and feeder relays can be reduced to 0.2 seconds at the maximum fault level. The result is that the backup clearing time is 0.15 seconds faster at the maximum fault level when static SFC overcurrent relays are used; at a fault limited to 1.5 times the pickup of the backup relay, static relays are a full 10 seconds faster in operation.

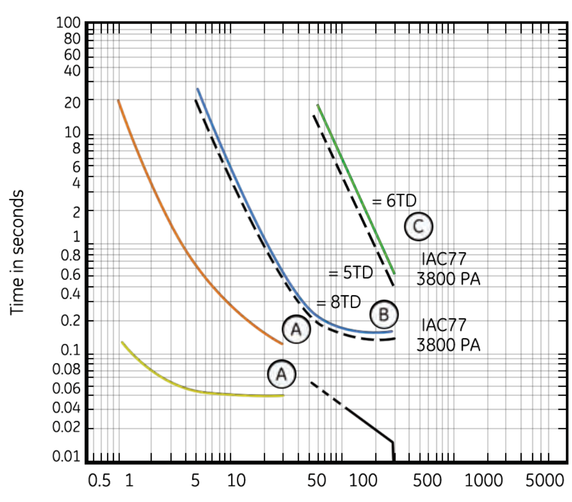


Figure 24.
Pole-type recloser vs IAC 77 relay coordination example

4. Ground Fault Detection

A complex problem, for which there is no ready solution, is high impedance ground-fault detection and protection. This is also a very serious problem in that personnel safety is involved, particularly so when a live conductor drops to the ground and there is insufficient fault current available to operate protective devices. Sensitivity is determined by the permissible unbalance in a four-wire grounded system and/or the number of breaker operation interruptions that can be tolerated. Where the majority of all faults that occur on a four-wire distribution system initiate as line-to-ground faults and where many are of the self-clearing type, it must be evaluated whether or not very sensitive ground tripping can be justified with the acceptance of the many unnecessary interruptions that can be expected.

4.1 Unbalance

The problem of setting ground-relay sensitivity to include all faults, yet not trip for heavy-load currents or load inrush, is not as difficult

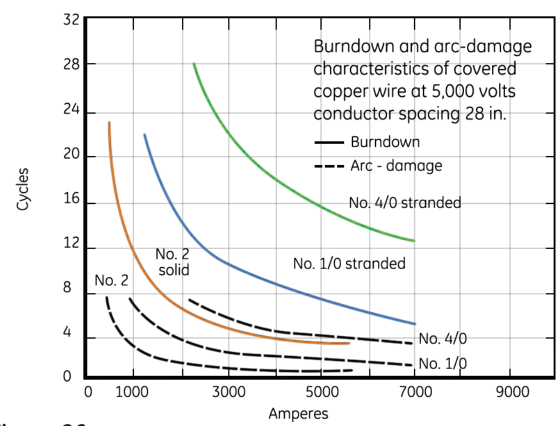


Figure 26.
Burndown characteristics of several weatherproof conductors

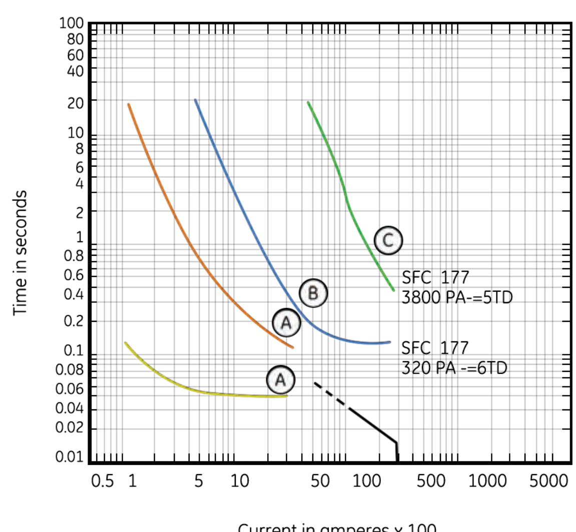


Figure 25.
Pole-type recloser vs SFC 177 relay coordination example

as it is for phase relays. If the three-phase load is balanced, normal ground current is near zero. Therefore, the ground relay should not be affected by load current and can have a sensitive setting. Unfortunately, it is difficult to keep the loads on the distribution system balanced to the point where ground relays can be set to pick up on as little as 25 percent of load current. Most ground relays are set to pick up at about 50 percent of load current.

4.2 Faults

The two basic factors affecting low-magnitude ground current are line impedance and fault impedance.

The line impedance can be readily calculated on the basis of a "bolted" fault. However, it is often recognized that in many cases the magnitude of measurable shortcircuit current is less than indicated by calculations. This is understandable in view of the many variables not accounted for in calculations. For example, conductor-splice resistance, reduced generating capacity, low system voltage at time of fault, voltage reduction due to the fault at the time of interruption, and error in calculations due to incorrect circuit footage, transpositions, and configurations. In addition, a big factor known to exist, but not possible to calculate or obtain from industry records, is fault impedance. This factor in itself can vary due to the type of fault, ground resistivity, contact pressure and weather and tree conditions. This factor has a decided effect in reducing the short-circuit current magnitude.

In 7.2/12.47 kV short-circuit calculations, a factor of 30, 35 or 40 ohms is often used as the fault resistance in determining minimum values of line-to-ground current available. However, these values are purely imaginative values without ample substantiation. The closest reference to this appears in AIEE Paper 49-175, Overcurrent Investigation on Rural Systems.

With the general acceptance by utility operators of the use of the coordinated recloser-fuse method of distribution line sectionalizing, the problem of high-impedance groundfault protection is greatly simplified in the fringe areas. However, the problem is further complicated in protection of the main circuit close to the substations. Where ground relays are generally accepted as a means of ground fault detection and protection, the minimum setting is usually established by the maximum unbalance that could exist with the heaviest loaded single-phase branch interrupted. In all probability, this setting will be less than the minimum pickup value of the nearest automatic circuit recloser. Hence, if reclosers are to be used out on the distribution feeder, ground relays must be adjusted to have a minimum pickup higher than 200 percent of the largest rated recloser or be disconnected entirely. When the ground relay is adjusted as high as required, it loses its effectiveness as ground protection.

It is possible to add time delay to the ground relays so that they may be set lower than the reclosers and still achieve coordination. This feature could be utilized to achieve back-up protection for some of the ground faults that are in the recloser protective zone

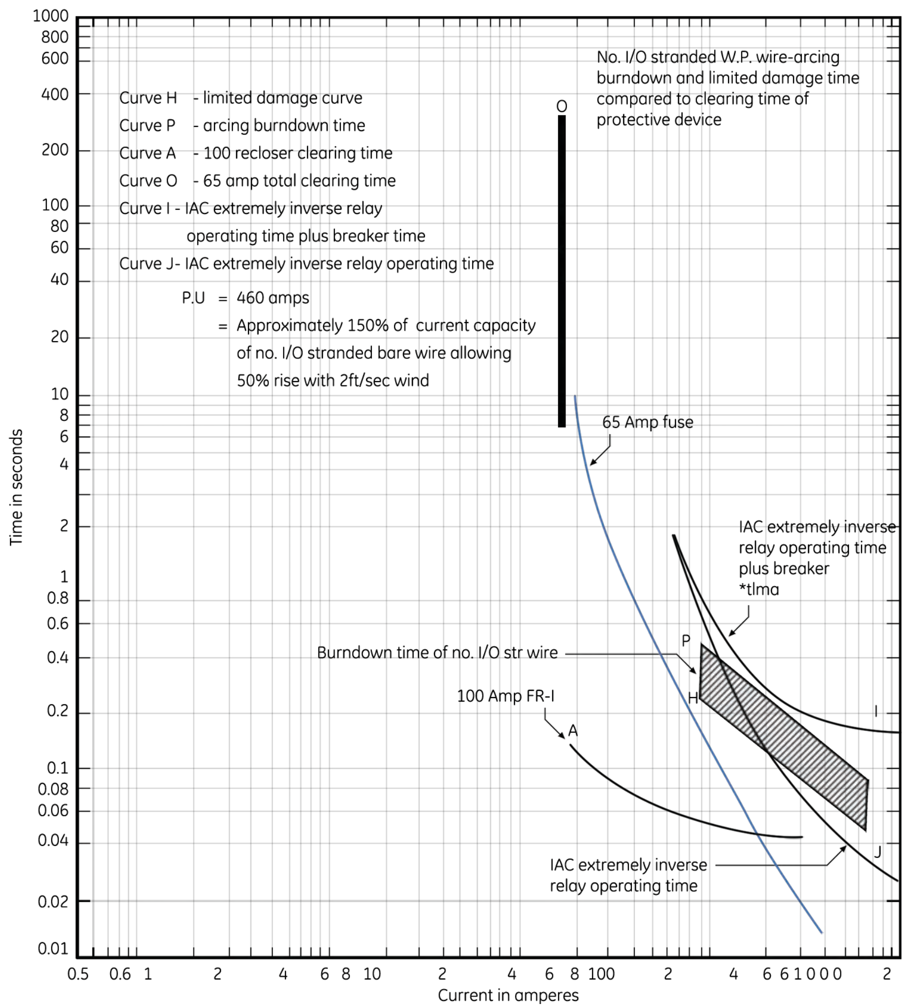


Figure 27.
Curves illustrating coordination between the arc damage and burndown characteristics for a No. I/O conductor land the protective devices which must operate to prevent serious conductor damage

and disconnect the feeder if the recloser fails to function.

The combination of low-rated reclosers and fuses properly coordinated and located on the branch and fringe ends of the circuit will provide the possibility of interrupting low values of ground current, i.e., where reclosers can be applied with thermal ratings approximately 30 percent greater than full-load current at the point of installation and do have adequate interrupting capacity. Thus the possibility of operating on low-magnitude ground current is more assured than if operation is dependent upon the ground current relays at the substation.

In a few cases, detection of a fallen conductor has been considered so important that loads have been connected line-to-line, so there could be no neutral current due to unbalance. The neutral has been grounded through high resistance to limit the ground current thus minimizing the effect of fault resistance on fault-current magnitude. Very sensitive ground relays have been installed with this system to assure clearing of conductors that have fallen.

THE PROPER USE OF RECLOSERS AND FUSES, ALONG WITH HIGHER SPEED BREAKERS, SHOULD PREVENT MOST CONDUCTOR BURNDOWN PROBLEMS

5. Conductor Burndown

Conductor burndown is a function of (1) conductor size (2) whether the wire is bare or covered (3) the magnitude of the fault current (4) climatic conditions such as wind and (5) the duration of the fault current.

If burndown is less of a problem today than in years past, it must be attributed to the trend of using heavier conductors and a lesser use of covered conductors. However, extensive outages and hazards to life and property still occur as the result of primary lines being burned down by flashover, tree branches falling on lines, etc. Insulated conductors, which are used less and less, anchor the arc at one point and thus are the most susceptible to being burned down. With bare conductors, except on multi-grounded neutral circuits, the motoring action of the current flux of an arc always tends to propel the arc along the line away from the power source until the arc elongates sufficiently to automatically extinguish itself. However, if the arc encounters some insulated object, the arc will stop traveling and may cause line burndown.

With bare conductors, on multi-grounded neutral circuits, the motorizing effect occurs only on the phase wire since current may flow both ways in the neutral. When the 25 percent of the burndown and the protective equipment should be installed to limit the currents and times to less than those given.

With tree branches falling on bare conductors, the arc may travel away and clear itself; however, the arc will generally re-establish itself at the original point and continue this procedure until the line burns down or the branch fails off the line. Limbs of soft spongy wood are more likely to burn clear than hard wood. However, one-half inch diameter branches of any wood, which cause a flashover, are apt to burn the lines down unless the fault is cleared quickly enough.

Figure 26 shows the burndown characteristics of several weatherproof conductors. Arc damage curves are given as arc is extended by traveling along the phase wire, it is extinguished but may be re-established across the original path. Generally the neutral wire is burned down.

Figure 27 shows the coordination between the arc damage and burndown characteristics for a No. I/O conductor and the protective devices which must operate to prevent serious conductor damage. This curve shows that with the present breaker operating times, the feeder breaker would afford little protection. It should be realized that the breaker time used was assumed to be eight cycles regardless of the fault current. In an actual case, the breaker time would probably be less than one half this value at its nameplate interrupting rating.

The use of automatic circuit reclosers and fuses will greatly improve the protection of conductors against burn down as shown in Figure 27. Proper utilization of reclosers and fuses should provide protection for all conductors within the current range shown. As systems increase in size, many engineers are worried about burndown becoming more of a problem since the available short-circuit current will increase. This problem may be delayed by the sectionalizing of buses and the addition of current-limiting reactors. It is quite possible that proper sectionalizing may delay the problem indefinitely for some systems.

The proper use of reclosers and fuses, along with higher speed breakers, should prevent most conductor burndown problems.

6. Appendix A

6.1 Functions and Definitions

The devices in the switching equipments are referred to by numbers, with appropriate suffix letters (when necessary), according to the functions they perform. These numbers are based on a system which has been adopted as standard for automatic switchgear by the American Standards Association.

Device No.	Function and Definition
11	CONTROL POWER TRANSFORMER is a transformer which serves as the source of AC control power for operating AC devices.
24	BUS-TIE CIRCUIT BREAKER serves to connect buses or bus sections together.
27	AC UNDERVOLTAGE RELAY is one which functions on a given value of singlephase AC undervoltage.
43	TRANSFER DEVICE is a manually operated device which transfers the control circuit to modify the plan of operation of the switching equipment or of some of the devices.
50	SHORT-CIRCUIT SELECTIVE RELAY is one which functions instantaneously on an excessive value of current or on an excessive rate of current rise, indicating a fault in the apparatus or circuit being protected.
51	AC OVERCURRENT RELAY is one which functions when the current in an AC circuit exceeds a given value.
52	AC CIRCUIT BREAKER is one whose principal function is usually to interrupt short-circuit or fault currents.

Device No.	Function and Definition
64	GROUND PROTECTIVE RELAY is one which functions on failure of the insulation of a machine, transformer or other apparatus to ground. This function is, however, not applied to devices 51N and 67N connected in the residual or secondary neutral circuit of current transformers.
67	AC POWER DIRECTIONAL OR AC POWER DIRECTIONAL OVERCURRENT RELAY is one which functions on a desired value of power flow in a given direction or on a desired value of overcurrent with AC power flow in a given direction.
78	PHASE-ANGLE MEASURING RELAY is one which functions at a pre-determined phase angle between voltage and current.
87	DIFFERENTIAL CURRENT RELAY is a fault-detecting relay which functions on a differential current of a given percentage or amount.

The above numbers are used to designate device functions on all types of manual and automatic switchgear, with exceptions as follows:

Feeders

A similar series of numbers starting.with 101 instead of 1, is used for the functions which apply to automatic reclosing feeders.

Hand reset

The term "Hand Reset" shall be added wherever it applies.

Letter suffixes

These are used with device function numbers for various purposes as follows:

1. CS - Control Switch　YY - Auxiliary Relay
   X - Auxiliary Relay　Z - Auxiliary Relay
   Y - Auxiliary Relay

2. To denote the location of the main device in the circuit or the type of circuit in which the device is used or with which it is associated, or otherwise identify its application in the circuit or equipment, the following are used:

   N - Neutral　SI - Seal-in

3. To denote parts of the main device (except auxiliary contacts as covered under (4) below), the following are used:

   H - High Set Unit of Relay　RC - Restraining Coil
   L - Low Set Unit of Relay　TC - Trip Coil
   OC - Operating Coil

4. To denote parts of the main device such as auxiliary contacts (except limit-switch contacts covered under (3) above) which move as part of the main device and are not actuated by external means. These auxiliary switches are designated as follows:

   "a"- closed when main device is in energized or operated position

   "b"- closed when main device is in de-energized or non-operated position

5. To indicate special features, characteristics, the conditions when the contacts operate, or are made operative or placed in the circuit, the following are used:

   A - Automatic　TDC - Time-delay Closing
   ER - Electrically Reset　TDDO - Time-delay Dropping Out
   HR - Hand Reset　TDO - Time-delay Opening
   M - Manual

To prevent any possible conflict, one letter or combination of letters has only one meaning on an individual equipment. Any other words beginning with the same letter are written out in full each time, or some other distinctive abbreviation is used.

How to set an IAC relay

Time and current settings of IAC relays are made by selecting the proper current tap and adjusting the time dial to the number which corresponds to the characteristic required. The following example illustrates the procedure.

Assume an IAC inverse-time relay in a circuit where the circuit breaker should trip on a sustained current of approximately 450 amperes, and that the breaker should trip in 1.9 seconds on a short-circuit current of 3750 amperes. Assume further that current transformers of 60:1 ratio are used.

Find the current tap setting by dividing the minimum primary tripping current by the current transformer ratio: g= 7.5 Since there is no 7.5-ampere tap, use the 8-ampere tap. TO find the time setting which will give 1.9-second time delay at 3750 amperes, divide 3750 by the transformer atio. This gives 62.5-amperes secondary current, which is 7.8 times the 8-ampere tap setting.

7. References

[1] Master Unit Substations and Their Relay and Control Arrangements, GE Publication QET-2528, by J. H. Easley and W. W. Walkley, Dec. 1955.

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[3] The Art and Science of Protective Relaying, by C. R. Mason, John Wiley and Sons, 1956.

[4] Evaluation of Distribution System Relaying Methods by A. J. McConnell, Presented at the Pennsylvania Electric Association, May 16-17, 1957.

[5] Type IAC Time Overcurrent Switchgear Protective Relays, GE Publication GET-7215, 1973.

[6] A Comparison of Static and Electromechanical Time Overcurrent Relay Characteristics, Application and Testing. by J. J. Burke, R. F. Koch, and L. J. Powell presented at PEA 1975.

[7] Burndown Tests Guide Distribution Design, by W. B. Goode and G. H. Gaertner, EL&P, Dec. 1966.

[8] Vertical Lift Metalclad Switchgear, GE Publication GEA-5664L.

[9] Relay Time-characteristic Curves

Model	TYPE		
	IAC	IFC	SFC
51	GES-7001	GES-7014	GES-7011
53	GES-7002	GES-7015	GES-7012
77	GES-7005	GES-7016	GES-7013

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Work Process Management: Integrating Complex Work Processes Across Utility Operations

Alan Blight
Infrastructure Industries, GE Intelligent Platforms

1. Introduction

Around the world, governments are funding new smart technologies and forcing changes in commercial and regulatory frameworks to accommodate the latest opportunities and risks.

The role of the electricity provider continues to evolve with expanded responsibilities, including the need to address increased compliance and accountability across operations.

Utilities can no longer consider individual functions in isolation, but need to consider the context of their systems as a whole, and face the requirement for better coordination between departments. It's imperative to improve communications between elements and to enhance processes and procedures, which now have to embrace multiple elements.

Some organizations have applied a services-oriented architecture (SOA) to enable diverse applications to publish information into a repository, which can be accessed via a real-time services bus. The repository and an associated development framework allow composite applications to be built, customized to an organization's needs using services and data provided from other applications, while protecting existing infrastructure investments.

This article discusses the benefits of implementing a Work Process Management system that leverages the SOA infrastructure. Work Process Management can manage increasingly complex processes—which may span several departments or domains—through real-time execution of workflows that regulate and analyze procedures.

A workflow is the automation of a process during which information or tasks move from one participant to another for action, according to a set of rules. The participants may be people, machines, or computers. As an enabling tool, Work Process Management software provides a system for improving and optimizing procedures—combining automated and manual processes through authoring, execution, and analysis capabilities. The software takes a process "flowchart" and digitizes it—connecting people, equipment and systems in real time—operating within seconds and subseconds.

2. Building on SOA Enables Integration

The first thing to remember is that having an SOA does not in itself solve any problems—SOA is an enabling technology, not a tool. What it does provide is a forum for applications and services to publish information that can be shared, and the key enablers are the real-time services bus and the repository.

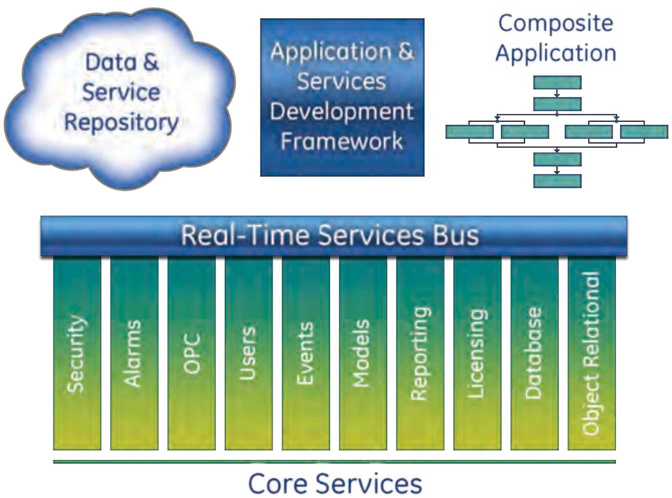


Figure 1.
Some organizations have applied a services-oriented architecture (SOA) to enable diverse applications to publish information into a repository, which can be accessed via a real-time services bus.

As a leading adopter of SOA, GE Intelligent Platforms leverages this technology as the backbone of its Proficy® software suite. Proficy SOA provides support that allows service providers from other products in the Proficy family to integrate and interact with a master Proficy SOA Server; third-party applications and databases can also integrate into Proficy SOA. This integration allows utilities to publish data and functionality from these products to the Data and Services Repository and access it from within the Proficy Client.

3. Proficy Workflow – Leveraging the Power of SOA

As an application that sits on top of the Proficy SOA infrastructure, GE's Work Process Management software solution called Proficy Workflow is a user-configurable, dynamic decision-making engine for integrating automated and manual business and production processes. Proficy Workflow is a good example of how SOA-enabled data and services can be assembled into a solution that transcends a single application.

Proficy Workflow consists of the following components:

- Tools for building data models.
- An execution engine (workflow) that uses a graphical editor for simplifying the construction of complex logic. Workflows are programs that execute activities and respond to events and data changes, and write values back out to the Proficy data models or through external connectors.
- A client console that can host editors for building applications and screens for monitoring plant activities, or display workflow tasks to operators in the plant and accept input into forms that can be built in Proficy and routed to clients throughout the enterprise.
- A configurable event engine that can initiate workflows and other code based on many different kinds of internal and external triggers.
- A security infrastructure that allows objects to be secured by role and location.

The models, events, and environment all rely on Proficy SOA to feed in data from other sources. Once a procedure has been written and checked, it can be invoked by either an event or a schedule, and routed to the appropriate operator or equipment. Standardized workflows maintain conformity across a utility, and these tools provide the core of a complete suite of applications that can be built to facilitate the management and analysis of activities.

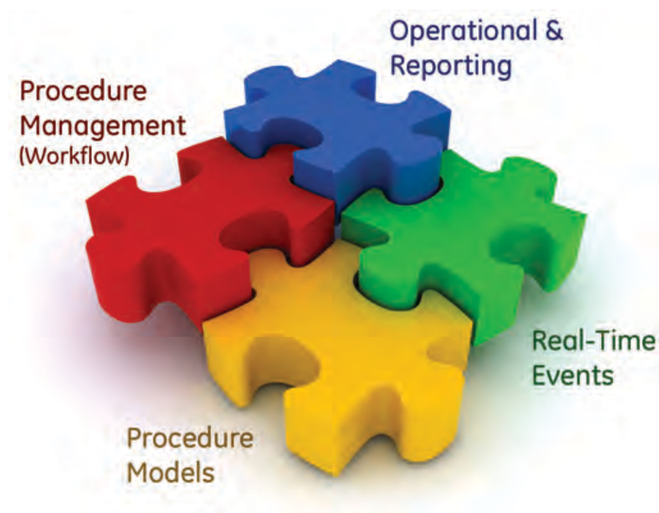


Figure 2.
Work Process Management can manage increasingly complex processes—which may span several departments or domains—through real-time execution of workflows that regulate and analyze procedures.

4. Why Create Workflows?

Currently, many procedures rely on paper manuals, standard operating procedures (SOPs), and checklists. Digitizing and formalizing these procedures captures the skills of a utility's best operators, ensures adherence to safety and regulatory procedures, and allows analysis and modification of procedures to meet changing business needs. It can also simplify life for the operator, automate some of the manual tasks, and provide an audit trail.

It is important to note that Work Process Management is different from the maintenance procedure tools found in Maintenance Schedulers. A workflow can apply to a maintenance procedure, in addition to much more, including Operations, Customer Care, Maintenance and HR domains. In fact, it applies to any procedure that contains a set of coordinated tasks and activities, conducted by both people and equipment, that leads to accomplishing a specific production or operational goal.

For example, most SCADA systems provide adequate alarm and event displays, but offer little guidance to the operator on what actions are required for a particular event. Similarly, recovery and maintenance procedures are often driven by controls outside the SCADA environment.

Consider the following questions:

- Are your operators seeing too many nuisance alarms?

- Could some of your alarms be handled automatically?
- When alarms are activated, are you confident that your operators will take the proper actions?
- Do you analyze and trend the root causes for alarms? Are you improving the trends week to week?
- Do you need to document alarms and corrective action for compliance?
- Do you know how well teams are following SOPs or established work processes?

A WORKFLOW IS THE AUTOMATION OF A PROCESS DURING WHICH INFORMATION OR TASKS MOVE FROM ONE PARTICIPANT TO ANOTHER FOR ACTION, ACCORDING TO A SET OF RULES.

5. Building and Authoring Workflows

Proficy Workflow has two environments, one for authoring and editing workflows and one for executing them.

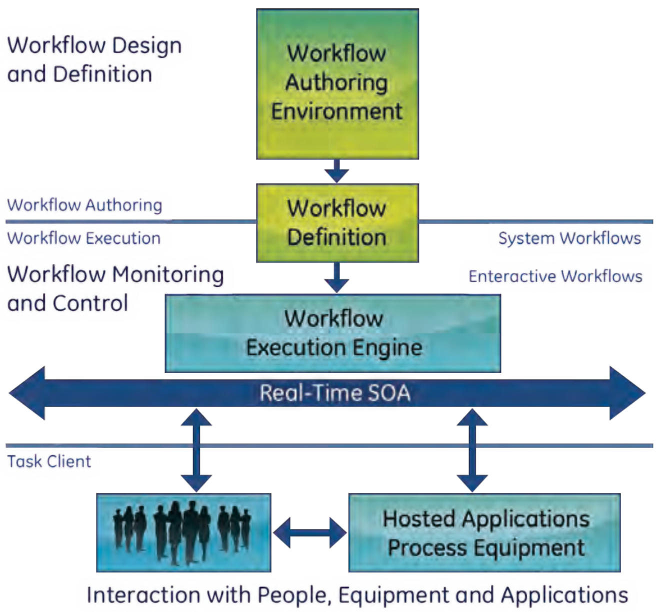


Figure 2.
Operations experts can create workflows in the Workflow Authoring Environment without requiring IT resources.

Industrial workflow typically does not require IT resources, and authors can easily make changes to the system. The graphical authoring environment permits drag-and-drop construction of workflow diagrams or the execution process.

Following definition, the workflow moves to the execution engine; a single process could have many workflows executing at the same time. In the case of an interactive workflow, the workflow then gets pushed to the next functional area, which is the task client with a list of tasks for a role and location.

In the case of a system workflow, the workflow does not have interaction with end users and runs behind the scenes.

The steps for authoring a workflow include:

1. Document a new or existing process.
2. Examine the process. By using Work Process Management, companies can look at their processes, often for the first time at this level, evaluate them, and make significant improvements.
3. Describe the event, or combination of events, that will trigger the workflow to execute. Triggers can range from particular data coming from an RTU, to a customer call center event, to information from a SCADA node. Users can combine several with one conditional statement to trigger a workflow. Or, users can trigger a workflow with time-based events.
4. Define the conditional process logic that specifies the tasks to be completed within the workflow.
5. Identify recipients and what data they require to make the correct decisions and to complete their tasks.

For every step within a workflow, users can attach documents and work instructions to assist and speed with execution.

6. Modeling the Process Using Standards

There is nothing to stop utilities from simply writing workflows, connecting the inputs and outputs to data, and carrying out work. However, if they take the time to build proper structures, they will be able to store data in a way that enables easy reporting and keeps data within the context of their operations—allowing them to analyze and compare similar operations.

To define and organize system and application information, Proficy Workflow uses models based on the ISA-95 format, which is broad and generic in scope, delivering the flexibility required to fit into numerous environments. Note that ISA-95 does not provide implementation, but rather, a structure to organize data and processes.

Although originally developed for the manufacturing industry, ISA-95 has now been extended to encompass any process related to plant operations, including maintenance, inventory, energy flow, and this allows the modeling process to apply beyond the traditional manufacturing base.

ISA-95 models in Proficy Workflow fit into two broad categories: resource models and process models.

- ISA-95 Resource Models - An ISA-95 resource is defined as an entity that provides some or all of the capabilities required by the execution of an activity and/or process. The ISA-95 resource models are divided into Equipment, Material, and Personnel. The equipment model is hierarchical, representing the structure of fixed assets from the enterprise down to the smallest hardware item. The material and personnel models are flat, although Proficy Workflow allows some organization of these objects to make navigating and locating them easier.

- ISA-95 Process Models - Process models in ISA-95 allow modeling of the requirements and performance data of the processes running inside the plant

7. Executing Workflows

Once a workflow has been triggered (either manually or by an event or schedule), the Work Process Management software handles the processing and sequencing of the actions, including routing for any required authorizations.

For example, the first task in the process may be routed to the appropriate operator; the operator may be informed by email, pager, screen popup, or new task list entry, that there is a task scheduled for him or her. The task will consist of one or more steps from the workflow.

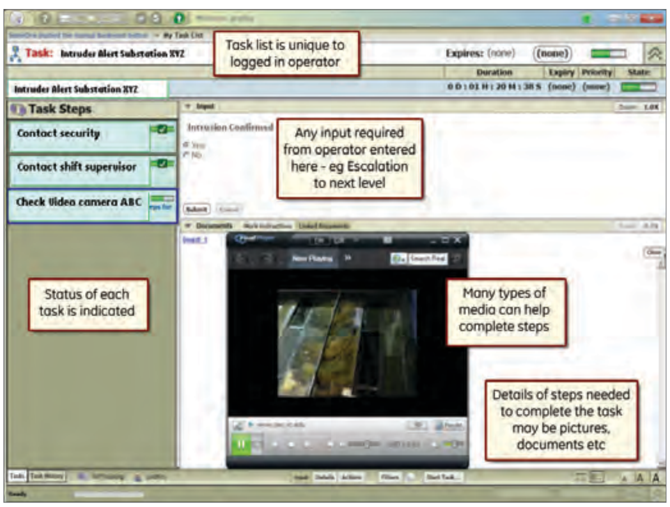


Figure 4.
Proficy Workflow provides step-by-step task instructions to operators, including video, pictures, documents or other instructional materials.

The task will appear on the operator workflow screen along with its current completion status. The screen can give details to the operator on how to complete the task, which can take the form of a step-by-step procedure, a maintenance instruction or other document, picture or even video input. The Work Process Management screen also allows the operator to input responses to the task or step, which for example, could include meter readings or other values, or a simple yes/no response.

8. Integrating Workflows With Other Applications

Proficy Workflow is intended to enhance, not replace, an existing structure and contains many tools to allow it to integrate with a utility's current applications, including databases and SCADAs. The most common environment for technical personnel is a SCADA or HMI screen, and Proficy Workflow allows organizations to embed workflows in their existing HMI via ActiveX controls.

9. Implementing Security

Security and accountability are critical requirements in an electric power infrastructure environment. Proficy Workflow provides security in several ways to prevent unauthorized users from accessing or modifying the system, requiring users to log in to gain access only to the areas to which they have been granted permission.

Maintaining adequate security in a business environment is complex. Proficy Workflow simplifies security configuration by abstracting the three main areas that are constantly changing in a facility:

- People/personnel
- Equipment
- Operational hierarchy of the people

New personnel are hired in an organization and some retire as well; equipment is added, replaced, and updated; and people are promoted (for example, from being an operator to a supervisor, and so on). Proficy Workflow provides security to accommodate all of these cases using three different constructs:

- People can be configured in groups; for example, Operations Group, Maintenance Group.

- Equipment is modeled with the ISA-95 Model Editor, which defines a plant in a hierarchical fashion. An electricity network will have multiple sites, and sites can have multiple areas, and so on.

- An operational hierarchy can be defined as a set of keys that each person can hold. For example, an operator can have keys to start and stop a workflow while a supervisor can have additional keys to create and delete a workflow.

10. Conclusion

A Work Process Management system, based on an SOA infrastructure, is a key element to connecting and managing flexible work processes and ensuring operations run smoothly. In the electric power industry, where compliance, adherence to SOPs, and accountability are vital, Work Process Management can provide an environment to control, analyze, and audit activities across multiple departments.

By leveraging a common reference model and workflow engine, utilities can effectively execute real-time workflows across many systems—building a solid and scalable foundation to gain a sustainable advantage.

041310-v3

CenterPoint Energy
Links Electricity and Communications to Create a Smart Grid

"The Advanced Metering System is our first step in developing a smart grid – comprised of technology, automation and electrical infrastructure integration." Kenny Mercado, Senior Vice President of Advanced Metering Deployment, CenterPoint Energy

"We selected WiMAX technology for our AMS because it enables the rugged, secure, scalable, two-way, high-speed private communications infrastructure necessary to achieve the Smart Grid outcomes desired." - Don Cortez, Division Senior Vice President Technology, CenterPoint Energy

CenterPoint Energy announced its Energy InSight[SM] program in early 2009. Energy InSight highlights CenterPoint's Energy Smart Grid initiatives and will integrate the technologies necessary to transform the way energy is bought, delivered, and used by consumers, retail electric providers (REPs), and the electric utility.

As the first step in deploying a Smart Grid for Houston, Texas, CenterPoint Energy's electric transmission and distribution subsidiary embarked on an effort to create an Advanced Metering System (AMS) of more than 2 million electric meters, over five years, across its electric service territory.

Establishing a Communications Infrastructure for the AMS

The key to any AMS is the retrieval and collection of meter data. The challenge for CenterPoint Energy was how to connect the 7,000 Itron OpenWay meter data collection devices to be located throughout the 5,000 square mile territory, needed to collect meter data and communicate with the meters being deployed into its private network.

CenterPoint Energy considered a number of different communications technologies. Critical to the selection of a technology and a vendor were the following minimum requirements:

- support for cyber security standards and support of open networking standards and protocols
- ability to provide high reliability and system availability
- ability to provide the bandwidth for network loading and future network capacity
- robust network management tools and processes
- a proven track record satisfying the needs of utility communication systems
- scalable to support the build-out over a five-year period
- rugged enough to withstand Houston's harsh weather conditions including heat, humidity, and hurricanes

Company:
CenterPoint Energy - Electrical Transmission & Distribution Subsidiary

www.centerpointenergy.com

Headquarters:
Houston, Texas

Overview:
CenterPoint Energy, Inc. is a domestic energy delivery company that includes electric transmission & distribution, natural gas distribution, competitive natural gas sales and services, interstate pipelines, and field services operations. The company serves more than five million metered customers primarily in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas.

GE Products and Services:
- MDS Mercury 3650
- Engineering Services
- Network Design
- Project Management
- Support Services

Project Scope:
- Create and deploy an Advanced Metering System (AMS) for more than 2 million meters over five years
- Total capital expenditure of approximately $640 Million
- Installation and complete integration of the Itron OpenWay meters and data collection devices
- Installation and complete integration of communications technologies including GE Digital Energy's MDS Mercury 3650 WiMAX radios and wireless access points
- Installation and complete integration of back office systems including a meter data management system

AMS Benefits:
- Help consumers achieve energy efficiency & facilitate faster transactions
- Allow Retail Electrical Providers (REPs) to expand service offerings
- Create operational efficiencies for CenterPoint Energy

CenterPoint Energy chose GE Digital Energy's MDS Mercury 3650 radios for its AMS communications network to provide network connectivity from the meter data collection devices to the existing CenterPoint Energy private network. In addition, GE Digital Energy will be providing the engineering, program management, and support services that will map out the WiMAX network and make it a reality.

How the AMS Communications Will Work

The AMS network will collect the data from the meters and pass it to the meter data collection devices over a wireless mesh network. Each of these 7,000 meter data collection devices will connect to a MDS Mercury 3650 WiMAX radio, which will transmit the meter information to one of approximately 100 MDS Mercury 3650 radio access points. The meter information will then be transmitted to CenterPoint Energy's data center, where the meter information will be stored and processed.

The Deployment

The AMS deployment started in January 2009 and the first meter was installed by March 1, 2009. By August 1, 2009, CenterPoint Energy had a functioning AMS and had deployed over 45,000 meters, over 300 meter data collection devices, 300 associated MDS Mercury 3650 WiMax radios, 11 MDS Mercury 3650 Radio access points, and the Itron and eMeter systems necessary to manage the meter information.

By the end of 2009, CenterPoint Energy's AMS deployment will have expanded to include more than 145,000 meters, 773 meter data collection devices, 773 MDS Mercury 3650 radios, and 26 MDS Mercury 3650 radio access points across Houston.

The Benefits of CenterPoint Energy's AMS

CenterPoint Energy's AMS, through its Energy InSight program, will help transform the purchase, delivery, and use of energy and will enable a business and electric market transformation. On-demand transactions and near real-time services - such as automated outage notification, remote meter reading, and remote connect/disconnect - will require new business processes.

CenterPoint Energy's goals of the AMS are to help Houston-area consumers achieve energy efficiency and cost savings by enabling user friendly access to detailed consumption information.

For REPs, the AMS will expand their ability to develop new service offerings including time-of-use rates and critical peak pricing, and establish a platform to offer future home appliance monitoring and control.

For the future Smart Grid, the AMS will enable more effective loading of utility assets, increased proactive monitoring and diagnostics to enhance the life of utility assets such as lines and transformers, and improve line fault detection and diagnostics.

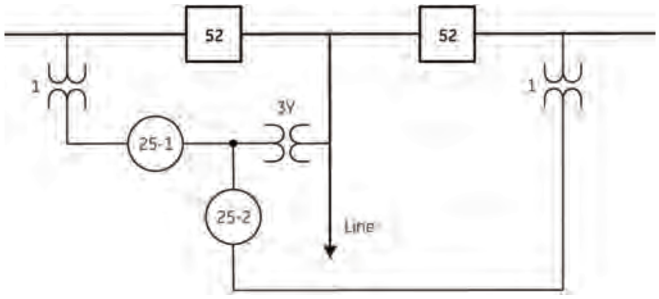
AMS is also an environmentally friendly solution that will enable demand-side management, facilitate integration of solar and wind generation into the grid, and promote energy efficiency through greater awareness of energy consumption by consumers.

AMS Data collection point with MDS Mercury 3650 Radio

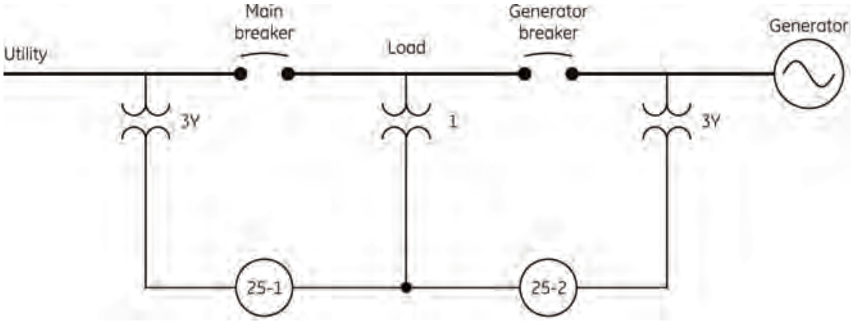
Synchronizing Multiple Buses Using Common Voltage Measurements

Introduction

There are several applications on the power system when it is necessary to synchronize one bus or line to two different buses or lines. One such application is reclosing a transmission line that uses dual breaker line terminals, such as breaker-and-a-half and ring bus. It is necessary to synchronize the line between each source separately, requiring two independent synchrocheck functions using a common voltage measurement from the transmission line.



A second application is a small generation system that can operate in parallel with the utility source, or serve and maintain load separate from the utility source. In this application, it is typical to synchronize voltages across the load bus. This method requires synchrocheck from the generator to the load bus, and from the utility source to the load bus. Both synchrocheck functions use a common voltage measurement from the load bus.



The traditional solution for either of these applications requires the use of two independent synchrocheck relays. The Multilin UR family of protection relays from GE provide two independent synchronism check functions in each relay. An individual UR device can have multiple voltage inputs to measure the synchronism voltages. Configurable analog signal sources allow any voltage measurement to be explicitly assigned to the two independent synchrocheck functions.

Voltage measurements in the UR family

The Multilin UR family is a modular platform, allowing great flexibility when configuring a relay for a specific application. A key module for the UR device is the “magnetics” or digital signal processing (DSP) CT/VT module that directly measures current and voltage from the power system. Each CT/VT module has two banks of input signals, and each bank accepts four current or four voltage measurements. A voltage bank measures three phase voltages (VA, VB, VC) and an auxiliary voltage. The auxiliary voltage can be assigned as any single-phase voltage measurement, including zero-sequence voltage. Therefore, applications for two independent synchrocheck functions require the use of two voltage banks. Practically, this requires the use of two CT/VT modules in a UR device.

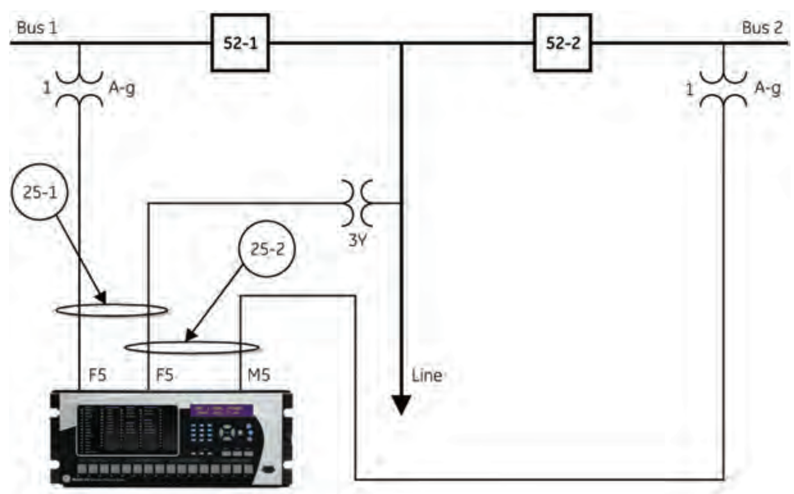
Analog signal sources

Analog signal sources (a "source") combine the physical current and voltage measurements from CT/VT modules together to create a single measurement point in the UR device. Protection functions are then configured to use a specific source or sources. This allows great flexibility in assigning different protection functions in the UR device to protect different equipment. A source can include any combination of phase current, ground current, phase voltage, and auxiliary voltage measurements. For a given protection function, these measurements can be drawn from any CT/VT module installed in the UR device. Any specific measurement can be used in more than one source.

The synchrocheck function in the UR device uses two different sources for the two voltage measurements. These two sources can be three-phase or single-phase voltage measurements. The application of two independent synchrocheck functions described here therefore requires the use of at least three sources.

Synchrocheck example 1: dual-breaker line terminals

This example uses the D60 Line Distance Protection System measuring the three-phase line voltage, and two different single-phase synchronism voltages (the configuration is the same for the L60, L90, and C60 devices). This example also assumes an 8L module (one current bank and one voltage bank) in the "F" slot of the relay, and an 8L module in the "M" slot. For synchronizing to either bus, the relay uses a phase A-to-ground voltage measurement.



The following steps are used configure a UR device to synchronize across multiple buses.

1. Configure the voltage inputs.
2. Configure the voltage signal sources.
3. Configure the synchrocheck functions.

Voltage inputs

Each voltage bank has three phase voltage inputs and an auxiliary voltage input. The inputs are labeled based on the first terminal of the bank. Therefore "F5" means the voltage bank that is associated with the 8L module in the "F" slot, and terminals F5 (VA), F6 (VB), F7 (VC), and F8 (VX). The three-phase voltages are configured for Wye or Delta connection, with the appropriate turns ratio. The auxiliary voltage is configured as appropriate: a specific phase-ground voltage (phase A-to-ground in this example), phase-to-phase voltage, or auxiliary voltage.

PARAMETER	VT F5	VT M5
Phase VT Connection	Wye	Wye
Phase VT Secondary	66.4 V	66.4 V
Phase VT Ratio	100.00 :1	100.00 :1
Auxiliary VT Connection	Vag	Vag
Auxiliary VT Secondary	66.4 V	66.4 V
Auxiliary VT Ratio	100.00 :1	100.00 :1

A-g auxiliary voltage for synchrocheck

Three-phase voltage for line

Voltage connections for synchrocheck applications can be either phase-to-ground voltages or phase-to-phase voltages. However, synchrocheck only works when the voltages in both sources are the same type: either both phase-to-ground or both phase-to-phase voltages.

Voltage sources

The synchrocheck function in the UR device must use two different signal sources as inputs. Therefore, this application requires three signal sources: one for each bus voltage and one for the protected line. Each source can be either a single-phase source or a three-phase source. When using a three-phase source and a single-phase source, the UR device automatically selects the correct voltage from the three-phase source to compare to the single-phase source. If using two single-phase sources, then both signal sources must use the same relative voltage (VAG to VAG, VAB to VAB, etc.) The three sources, when configured, look like:

PARAMETER	SOURCE 1	SOURCE 2	SOURCE 3
Name	52-1	52-2	Line
Phase CT	F1	M1	F1+M1
Ground CT	None	None	None
Phase VT	None	None	F5
Aux VT	F5	M5	None

A-g voltage from bus 1

A-g voltage from bus 2

Three-phase voltage from line

Source 1 is the A-phase-to-ground voltage from bus 1. This source also included the current flowing through breaker 52-1.

Source 2 is the A-phase-to-ground voltage from bus 2. This source also included the current flowing through breaker 52-2.

Source 3 is the three-phase voltage on the protected line. This source also includes the total line current, which is the summation of the currents from each breaker supplying the line.

Synchrocheck function

Configuring the synchrocheck function is a matter of selecting the appropriate sources for each function, then entering settings as appropriate. In this example:

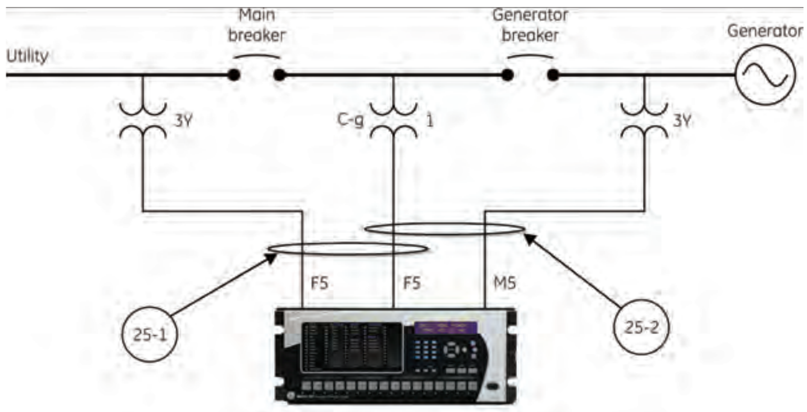
PARAMETER	SYNCHROCHECK1	SYNCHROCHECK2
Function	Enabled	Enabled
Block	OFF	OFF
V1 Source	LINE (SRC 3)	LINE (SRC 3)
V2 Source	BKR 1 (SRC 1)	BKR 2 (SRC 2)
Max Volt Diff	37000 V	37000 V
Max Angle Diff	40 deg	40 deg
Max Freq Diff	0.04 Hz	0.04 Hz
Freq Hysteresis	0.06 Hz	0.06 Hz
Dead Source Select	None	None
Dead V1 Max Volt	0.20 pu	0.20 pu
Dead V2 Max Volt	0.20 pu	0.20 pu
Live V1 Min Volt	0.80 pu	0.80 pu
Live V2 Min Volt	0.80 pu	0.80 pu
Target	Self-reset	Self-reset
Events	Disabled	Disabled

Synchronize line to bus 1

Synchronize line to bus 2

Synchrocheck example 2: small generator paralleling

This example uses a G30 Generator Protection System to provide generator protection, and utility interface protection. The G30 also provides synchrocheck capability between the generator and the load bus, and the utility interface and the load bus (configuration is the same for a G60 device). The G30 measures a three-phase voltage from the utility source using the type "8L" CT/VT module installed in the "F" slot, a three-phase voltage from the generator using an "8L" module installed in the "M" slot. The load bus voltage is the phase C-to-ground voltage, measured by the auxiliary voltage input of the module in the "F" slot.



The steps to configuring the G30 for dual synchrocheck functions are the same as for example 1, with only some differences in the actual settings.

Voltage inputs

The three-phase utility voltage and three-phase generator voltage are configured as wye connected voltage measurements. The single-phase load bus voltage is configured for a phase C-to-ground voltage. The voltage ratings and turns ratio of the instrument transformers is set as appropriate to the specific application.

PARAMETER	VT F5	VT M5
Phase VT Connection	Wye	Wye
Phase VT Secondary	120.0 V	120.0 V
Phase VT Ratio	1.00 :1	1.00 :1
Auxiliary VT Connection	Vcg	Vcg
Auxiliary VT Secondary	120.0 V	120.0 V
Auxiliary VT Ratio	1.00 :1	1.00 :1

Three-phase voltage from utility source

Three-phase voltage from generator source

C-g auxiliary voltage from load bus for synchrocheck

Voltage sources

This example uses three voltage sources for synchrocheck: the "Util" source to measure the three-phase voltage from the utility, the "Gen" source to measure the three-phase voltage from the generator, and the "Sync" source to measure the phase C-to-ground voltage from the load bus.

PARAMETER	SOURCE 1	SOURCE 2	SOURCE 4
Name	Util	Gen	Sync
Phase CT	F1	M1	None
Ground CT	None	None	None
Phase VT	F5	M5	None
Aux VT	None	None	F5

Three-phase voltage from utility source

Three-phase voltage from generator

Single-phase voltage from load bus

Synchrocheck function

As before, configuring the synchrocheck function is a matter of selecting the appropriate sources for each function, and then entering settings. In this example:

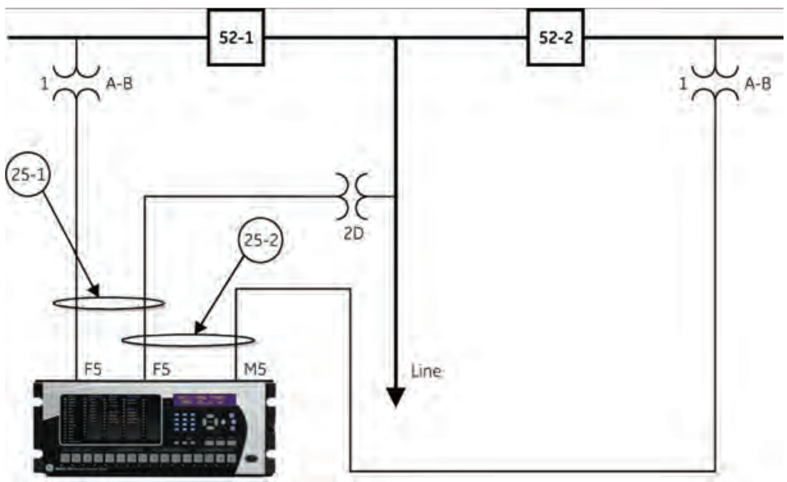
PARAMETER	SYNCHROCHECK1	SYNCHROCHECK2
Function	Enabled	Enabled
Block	OFF	OFF
V1 Source	Util (SRC 1)	Gen (SRC 2)
V2 Source	Sync (SRC 4)	Sync (SRC 4)
Max Volt Diff	10 V	10 V
Max Angle Diff	10 deg	10 deg
Max Freq Diff	1.00 Hz	1.00 Hz
Freq Hysteresis	0.06 Hz	0.06 Hz
Dead Source Select	LV1 and DV2	LV1 and DV2
Dead V1 Max Volt	0.30 pu	0.30 pu
Dead V2 Max Volt	0.30 pu	0.30 pu
Live V1 Min Volt	0.70 pu	0.70 pu
Live V2 Min Volt	0.70 pu	0.70 pu
Target	Disabled	Disabled
Events	Disabled	Disabled

Synchronize utility to load bus

Synchronize generator to load bus

Synchrocheck example 3: using phase-to-phase voltages

In many applications, particularly at distribution voltages, only phase-to-phase voltages are available. It is still possible to use multiple synchrocheck elements in the UR family in this case. However, both voltage sources in a one synchrocheck element must use phase-to-phase voltages.



The steps to configuring the G30 for dual synchrocheck functions are the same as for example 1, with only some differences in the voltage input settings.

Voltage inputs

The three-phase line voltage is configured as delta-connected phase-to-phase voltage measurements. The auxiliary synchrocheck voltages therefore must be a phase-to-phase voltage, the A-B voltage in this example. The voltage ratings and turns ratio of the instrument transformers is set as appropriate to the specific application.

PARAMETER	VT F5	VT M5
Phase VT Connection	Delta	Wye
Phase VT Secondary	115.0 V	66.4 V
Phase VT Ratio	1400.00 :1	1.00 :1
Auxiliary VT Connection	Vab	Vab
Auxiliary VT Secondary	115.0 V	115.0 V
Auxiliary VT Ratio	1400.00 :1	1400.00 :1

Three-phase line voltage measured by two delta-connected VTs

A-B auxiliary voltage for synchrocheck

A-B auxiliary voltage for synchrocheck

Voltage sources

This example uses three voltage sources for synchrocheck: the "BKR 1" source to measure the phase-to-phase synchrocheck voltage from one bus, the "BKR 2" source to measure the phase-to-phase synchrocheck voltage from the second bus, and the "LINE" source to phase-to-phase voltages on the protected line.

PARAMETER	SOURCE 1	SOURCE 2	SOURCE 3
Name	BKR 1	BKR 2	LINE
Phase CT	F1	M1	F1+M1
Ground CT	None	None	F1
Phase VT	None	None	F5
Aux VT	F5	M5	None

Phase-to-phase auxiliary voltage from bus 1

Phase-to-phase auxiliary voltage from bus 2

Three-phase voltage using two delta-connected VTs

Synchrocheck function

As before, configuring the synchrocheck function is a matter of selecting the appropriate sources for each function, and then entering settings. In this example:

PARAMETER	SYNCHROCHECK1	SYNCHROCHECK2
Function	Enabled	Enabled
Block	OFF	OFF
V1 Source	LINE (SRC 3)	LINE (SRC 3)
V2 Source	BKR 1 (SRC 1)	BKR 2 (SRC 2)
Max Volt Diff	37000 V	37000 V
Max Angle Diff	40 deg	40 deg
Max Freq Diff	0.04 Hz	0.04 Hz
Freq Hysteresis	0.06 Hz	0.06 Hz
Dead Source Select	None	None
Dead V1 Max Volt	0.20 pu	0.20 pu
Dead V2 Max Volt	0.20 pu	0.20 pu
Live V1 Min Volt	0.80 pu	0.80 pu
Live V2 Min Volt	0.80 pu	0.80 pu
Target	Self-reset	Self-reset
Events	Disabled	Disabled

Synchronize line to bus 1

Synchronize line to bus 2

Summary

Providing multiple synchrocheck functions is a practical challenge for most microprocessor-based relays. Specific models of the Multilin UR family from GE include two synchrocheck functions. The modular platform of the UR family allows the measurement of multiple sets of three-phase and single-phase voltages. The use of analog signal sources provides easy configuration of the UR device to distinguish between individual voltage measurements to provide synchrocheck between a transmission line and two different buses, or between a generator, utility source, and load bus.

References

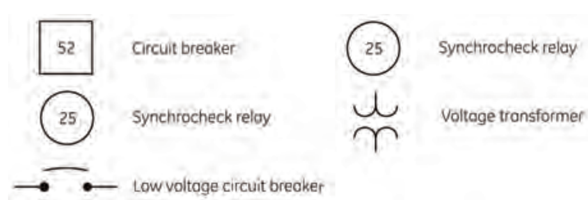
[1] B. Kasztenny, K. Kuras, "The Source Concept Considerations in a Protective Relay", GE Multilin publication GER-3985, Markham, Ontario, Canada, 2001.

[2] D60 Line Distance Relay Instruction Manual, GE Multilin publication GEK-113317A, Markham, Ontario, Canada, 2007.

[3] Configuration examples developed in cooperation with PowerSecure, Wake Forest, NC.

Symbols

The following symbols are used in this document.



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Industry Innovations

Featured Innovation

Intuitive and Intelligent Motor and Transformer Protection

Multilin 339 and 345 Protection Relays
GE Digital Energy – Multilin
www.GEDigitalEnergy.com/multilin

The 339 Motor Protection System and 345 Transformer Protection System offer advanced protection and simultaneous communications with multi-protocol support in a draw-out construction. Providing protection, control, monitoring, metering, and both local and remote user interfaces in one assembly, these relays eliminate the need for additional discrete components. As part of the SR 3 family of protection relays, the 339 and 345 relays provide extensive diagnostic information allowing users to trouble shoot and minimize downtime. Supported by the industry leading EnerVista Software Suite, these relays streamline workflow processes and simplify engineering tasks such as configuration, wiring, testing, commissioning, and maintenance.

Quick and Easy Manual Testing

CMControl Front Panel Control Device
Omicron
www.omicronusa.com

The CMControl is a unique front panel control device for the Omicron CMC 356, CMC 353, CMC 256Plus, and CMC 256-6 test sets. Used as an alternative to the powerful PC based Test Universe Software, its instant availability and easy operation make it the ideal solution for the quick verification of test objects. The device can also be detached from the test set and used as a flexible handheld controller.

Wireless Long Range Data Acquisition

MDS SD2
GE Digital Energy - MDS
www.GEDigitalEnergy.com/MDS

The MDS SD2 is the next generation in licensed narrowband radios at 200 MH. Part of the SD Series, the MDS SD2 is an industrial wireless solutions that provides long distance communications over licensed radio bands, allowing users to interface to both Ethernet and serial controllers such as PLCs, RTUs and SCADA systems. The software-controlled digital radio is compatible with previous generations, allowing for a smooth and controlled upgrade to existing systems. Monitor and control oil & gas well, compressor stations, pipelines, fluid storage tanks, pole tap transformers, circuit reclosers, capacitor banks, plus many other applications.

Thermal Imaging for SF_6 Gas Detection

GasfindIR LW Infrared Camera
Flir
www.flir.com

FLIR's GasfindIR LW infrared camera can sense Sulfur Hexafluoride (SF6). based on a unique, technology, FLIR's GasFindIR-LW is a one-of-a-kind infrared camera designed to help utility companies to better control Sulfur Hexafluoride (SF6) emissions. New features for utilities address the need to boost productivity across a range of climates and environments. For more than 50 years, thousands of utilities worldwide have used infrared thermography to avoid lost revenues, improve service reliability, and prevent hazards to workers and the public.

Industry Innovations

The Engineer's Toolbox for all Single Phase Relay Testing

SVERKER 750/780 Relay Test Set
Megger
www.megger.com

The SVERKER 750/780 Relay Test Set is the engineer's toolbox. The control panel features a logical layout, still SVERKER 650 users will find it comfortably familiar and will be able to start work right away. The SVERKER 750/780 features many functions that make relay testing more efficient. For example, its powerful measurement section can display (in addition to time, voltage and current) Z, R, X, S, P, Q, phase angle and cos ϕ. The voltmeter can also be used as a 2nd ammeter (when testing differential relays for example). All values are presented on a single easy-to-read display.

Protect Critical Substation Equipment with Surge Protection

EI-MSB10-400 Surge Protector
Electro Industries
www.electroind.com

Designed specifically to protect substation equipment from dangerous spikes and transients, the EI-MSB10-400 absorbs the event utilizing a multi-stage transient suppression scheme, before critical equipment is reached. This unit is very low cost and is essential to significantly improve equipment reliability. The EI-MSB10-400 surge protector is designed to protect sensitive equipment from the damaging effects of lightning strikes and/or industrial switching surges in single phase AC networks up to 320VAC (L-N / L-G), and DC networks up to 400 VDC.

Test RF Installations with Rugged Handheld Device

N9330B Handheld Cable and Antenna Tester
Flir
www.agilent.com

N9330B is a handheld, easy to use, battery operated cable and antenna tester for field installation and maintenance. It measures return loss, SWR, cable loss and distance-to-fault test functions for wireless service providers (WSPs), Aerospace & Defense customers, TV & Broadcasting customers and contractors.

2-in-1 Close Quarters AUTOFEED™ Cutter

Model 118 Close Quarters AUTOFEED™ Cutter
RIDGID
www.ridgid.com

The RIDGID Model 118 Close Quarters AUTOFEED™ Cutter can now be enhanced with a ratchet handle that allows for easier cutting in tight, restricted spaces. Of rugged and compact design, the handle can be attached to the cutter and operated in ratchet steps as smalls as 10 degrees. The allows for fine indexing of the cutter to operate in tight spaces. The new ratchet handle allows for more flexibility and mobility while keeping the AUTOFEED features of the model 118 Cutter, which is designed to cut hard and soft copper, aluminum and brass.

Upcoming Events

WPDAC	Apr 13 – 15	Spokane, Washington, United States

The Western Power Delivery and Automation Conference (WPDAC) is a two-and-half day conference that focuses on the fast-growing issues of automation and control of power system substations. Conference sessions encompass:

- Networks-Protocols & Communication
- Case Studies & Applications
- Security
- Control & Automation Logic
- SCADA & Wide Area Measurements
- Engineering & Project Management

The Davenport Hotel
www.conferences.wsu.edu/wprc

Visit GE Digital Energy in the Exhibition Area

IEEE PES T&D	Apr 19 – 22	New Orleans, Louisiana, United States

The 2010 IEEE PES Transmission & Distribution Conference & Exposition is designed and organized to provide the international power-delivery community with the information and details necessary to manage technology and business solutions now and in the decades ahead.

Topics include:

- IEC61850 Protocol (Station and Process Bus)
- Phasor Measurement Units
- Demonstration of IEC61850 Station Bus and Process Bus
- Demonstration of Protective Relay Programmable Logic

Ernest N Morial Convention Center
www.ieeet-d.org

Visit GE Digital Energy in Booth 2815, Hall I2

Visit GE's Application Lab - Booth G1, Hall G

Georgia Tech	May 4-7	Atlanta, Georgia, United States

The 64th Annual GeorgiaTech Protective Relaying Conference is an education forum for the presentation and discussion of broad and detailed technical aspects of protective relaying and related subjects.

GE Digital Energy – Technical Paper Presentations:

- Fully Utilizing IED Capability to Reduce Wiring
- Reliability of Protection Systems - What Are the Real Concerns
- Determining Settings for Capacitor Bank Protection
- Communications for the Smart Grid
- Practical Application of Ethernet within the Substation & Industrial Facilities
- Fault Locator Based on Line Current Differential Relay Synchronized Measurements

Atlanta Renaissance Hotel Downtown
www.pe.gatech.edu/courses/protective-relaying-conference

Visit GE Digital Energy – Technical Seminar – Ballroom B

Visit GE Digital Energy – Hospitality Suite & Application Showcase – Ballroom B

Upcoming Events

CIM	May 9-12	Vancouver, British Columbia, Canada

Celebrating its 27th anniversary, the 2010 Canadian Institute of Mining (CIM) Conference and Exhibition will focus on "Mining – Your Foundation for a Better World", reflecting the key role mining plays in the social and technical development of global communities. Leading equipment, technology, process, and services will be on display.

Vancouver Convention Centre
www.cim.org/vancouver2010

Visit GE Digital Energy in Booth 0501

IEEE REPC	May 16 – 19	Orlando, Florida, United States

The IEEE Rural Electric Power Conference is geared toward the practicing utility engineer working for a rural electric cooperative, an investor owned utility or a municipal electric utility. Consulting engineers and educators involved in medium and high voltage electric power system planning and design will also benefit from exposure to the advanced technologies and applications methods presented as part of the conference forum.

GE Digital Energy – Technical Paper Presentations:

- High Impedance Fault Detection on Rural Electric Distribution Systems
- Fully Utilizing Intelligent Electronic Devices Capability to Reduce Wiring in Rural Electric Distribution Substations

Caribe Royale Orlando
www.ieeerepc.org

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APPA	Jun 19-23	Orlando, Florida, United States

The American Public Power Association (APPA) National Conference & Public Power Expo is an annual event that attracts more than 1,500 individuals active in the public power industry. The conference will feature sessions on key topics facing the electric utility industry and public power, covering all facets of utility governance and operations.

Orlando World Center Marriott
www.appanet.org

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IEEE PPIC	Jun 21-23	San Antonio, Texas, United States

In its 56th year, the annual IEEE Pulp & Paper Industry Technology Conference focuses on the equipment and challenges faced by electrical engineering, maintenance and safety professionals in mill applications

GE Digital Energy – Technical Paper Presentations:

- Enhanced Algorithm for Motor Rotor Broken Bar Detection
- Impact of CT Error on Protective Relays
- Fully Utilizing IED Capability to Reduce Wiring
- Efficient Applications of Bus Transfer Schemes

Omni "La Mansion" Hotel
www.pulppaper.org

Visit GE Digital Energy in Booth 6

Upcoming Events

PAC World | Jun 21-24 | Dublin, Ireland

The Protection, Automation and Control (PAC) World Conference brings together members of the PAC World community, professionals and utilities and universities, manufacturers and consultants. Attendees will gain insights into the challenges, the requirements and the solutions that needs to be part of the Smart Grid.

Trinity College
www.pacw.org

Visit GE Digital Energy in Booth 8

SEE 2010 | Jun 23-25 | Miami, Florida, United States

The Southeastern Electrical Exchange (SEE) Annual Conference & Tradeshow provides attendees with in-depth presentations by industry experts on the latest issues and applications. This three day event will provide the opportunity to see the latest products and services for the utility industry.

Doral Golf Resort & Spa
www.theexchange.org

Visit GE Digital Energy – Multilin in Booth 401 & 403

CIGRE | Aug 22-27 | Paris, France

CIGRE (International Council on Large Electric Systems) is one of the leading worldwide Organizations on Electric Power Systems covering their technical, economic, environmental, organizational and regulatory aspects. This years event focuses on the need for increased intelligence in power systems and large disturbances.

GE Digital Energy, Multilin - Technical Paper Presentations:

- Optimal control of microgrid resources

Other GE Technical Paper Presentations:

- Impact of high levels of wind and other variable renewable generation on the grid operation: summary of major US studies
- A comprehensive approach for studying the economic and reliability impacts of greenhouse gas policies

Palais des Congres
www.cigre.org

Visit GE Digital Energy in Booth 66

CUEE 2010 | Sep 14-15 | Toronto, Ontario, Canada

Canadian Utilities Equipment & Engineering Show

The Canadian Utilities Equipment & Engineering Show is Canada's largest trade and exposition show dedicated to transmission, distribution & utility equipment.

International Center
www.cuee.ca

Visit GE Digital Energy in Booth 429

Upcoming Events

IEEE PCIC | Sep 20-22 | San Antonio, Texas, United States

The Petroleum and Chemical Industry Committee (PCIC) of the Industry Applications Society of IEEE hosts its 57th annual conference. This conference is an international forum for the exchange of electrical applications and technology related to the petroleum and chemical industry. The annual conference is rotated across North American locations of industry strength to attract national and international participation.

GE Digital Energy – Technical Paper Presentations:

- Design & implementation of an industrial facility islanding and load shed system
- Method for Arc-Flash detection in low voltage systems
- Motor Reacceleration to Improve Process Uptime

Other GE papers:

- Induction vs. Synchronous Motors - Different Perspectives: End User / Motor Manufacturer
- A comparative study between copper and aluminum induction squirrel cage constructions
- DC Motor Breaker Primer

San Antonio Marriott Rivercenter Hotel
www.ieee-pcic.org

Visit GE Digital Energy in our Hospitality Suite

Utility Tech | Sep 27-30 | Auburn, Alabama, United States

The 2010 Southeastern Distribution Apparatus School and Conference provides a forum for electric utility substation and apparatus department personnel to discuss common problems and new technologies with representatives from the industry.

The Hotel at Auburn University
www.utilitytech.org/apparatus.html

Visit GE Digital Energy in the Exhibit Hall

WPRC | Oct 19-21 | Spokane, Washington, United States

The Western Protective Relay Conference (WPRC) is an educational forum for the presentation and discussion of broad and detailed technical aspects of protective relaying and related subjects. Approximately 550 people attend, mostly from the western United States. This forum allows participants to learn and apply advanced technologies that prevent electrical power failures. Speakers are invited to present papers selected by a group of protective relaying experts.

GE Digital Energy – Technical Paper Presentations:

- The Power of IEC61850 for Bus Transfer Applications
- Adaptive Reclosing for DA Applications
- Differential Protections For Transformers with Standard and Non-Standard phase Shift
- How Frequency Measurements can Impact Security of Frequency Elements in Digital Relays

Red Lion Hotel and Spokane Conference Center
www.conferences.wsu.edu/wprc

Visit GE Digital Energy in the Exhibition Area

Upcoming Events

MIPSYCON	Nov 2-4	Brooklyn Center, Minneapolis, United States

The This conference provides electric utility engineers and consultants the opportunity to stay abreast of today's power system technology. The conference emphasizes the unique challenges faced by electric utilities in the Midwest. The conference also serves as a forum for power engineers to meet with their colleagues from other utilities to discuss mutual concerns. Topic areas include substations, utility industry futures, delivery systems, project management, relaying, distribution automation and distributed resources.

Earle Brown Heritage Center & Embassy Suites Minneapolis – Brooklyn Center
www.cce.umn.edu/Minnesota-Power-Systems/index.html

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Visit GE Digital Energy in Embassy Suites Minneapolis – Brooklyn Center

For the latest event information visit our website: www.gedigitalenergy.com/multilin/EventCalendar.htm

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GE Multilin 2010 Course Calendar

Comprehensive Training Solutions for
Protection, Control and Automation

SCHEDULED COURSES IN NORTH AMERICA

Courses for 2010	Tuition*	CEU Credits	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Fundamentals of Modern Protective Relaying	$2,400	2.8		19-22			12-15		13-16		15-18	
Introduction to the IEC61850 Protocol	$2,400	2.1			4-6					4-6		
Distribution Protection Principles & Relaying	$1,800	2.1			17-19			17-19				
Motor Protection Principles & Relaying	$1,800	2.1				8-10			28-30			7-9
UR Platform	$1,800	2.1		12-14		21-23		10-12		20-22		
UR Advanced Applications	$3,000	3.5			10-14					25-29		
Enervista™ Software Suite	$600	0.7				11		13				10
MM300 2 Days Hands-on	$1,200	1.4	16-17				26-27					
SR 350 Feeder Protection System	$1,200	1.4				1-2			21-22			
UR Applications (Houston, TX)	$1,800	2.1			11-13							
UR Advanced Applications (Pomona, CA)	$3,000	3.5				7-11						
Motors (SR469) & Feeder (SR750) (Atlanta, GA)	$1,800	2.1							7-9			
Motor & Feeder Relays (Dallas, TX)	$2,200	3.5								4-8		

All North American courses are located in Markham, Ontario, Canada unless otherwise stated
*Tuition quoted in US dollars

SCHEDULED COURSES IN EUROPE

Courses for 2010	Tuition*	CEU Credits	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Fundamentals of Modern Protective Relaying TRNGFMPR-S (English)	$2,400	2.8				7-10						13-16
Introduction to the IEC 61850 Protocol (English)	$2,400	1.4		22-23								
Distribution Protection Principles & Relaying TRNGDIST-S (English)	$1,800	2.1	9-11				6-8					
Motor Protection Principles & Relaying TRNGMOTR-S (English)	$1,800	2.1	23-25				20-22					
UR Platform TRNGURPL-S (English & Spanish)	$1,800	2.1			12-14				15-17		10-12	
UR Advanced Applications TRNGURAPPS (English & Spanish)	$3,000	3.5			17-21				20-24		15-19	
F650 Platform TRNGF650-S (English & Spanish)	$1,800	2.1				21-23				18-20		1-3

All European courses are located in Bilbao, Spain unless otherwise stated
*Tuition quoted in US dollars

Course dates are subject to change. Please visit our website at **www.GEMultilin.com/training** for the most up-to-date schedule.

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