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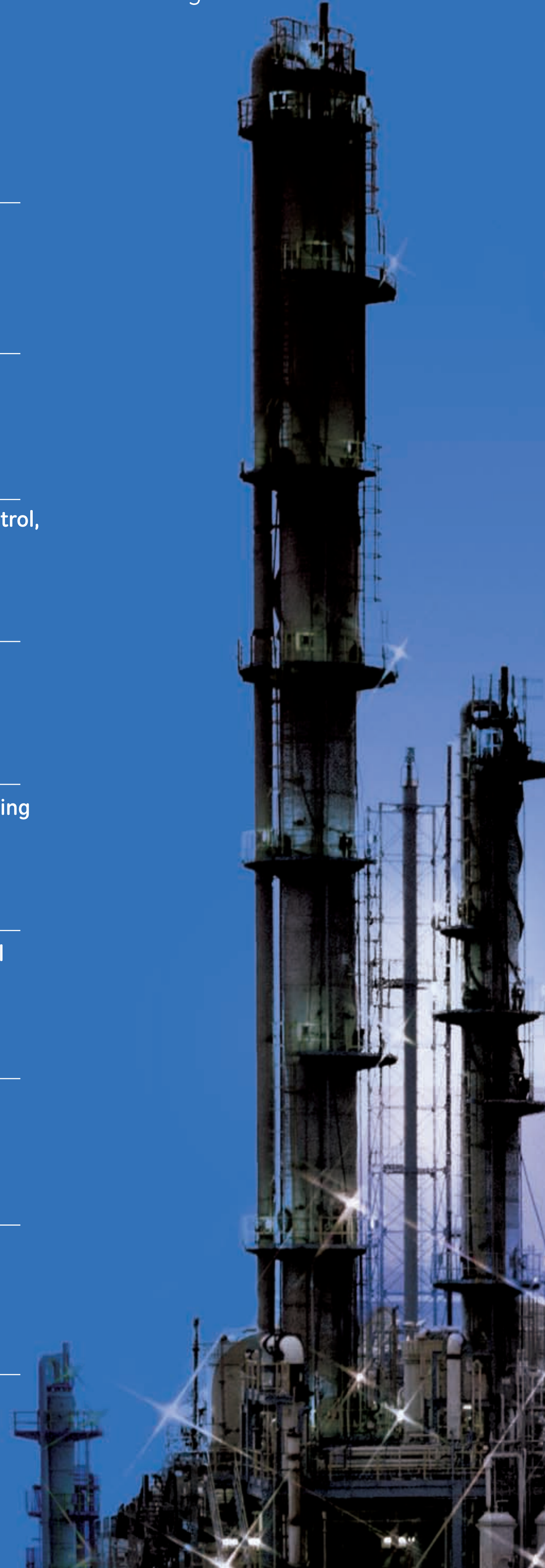

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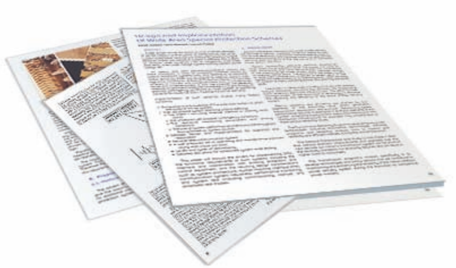

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Protection and Control Redundancy Considerations in Medium Voltage Distribution Systems

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1. Introduction

This paper is intended to raise some discussions on selected aspects of protection and control redundancy in distribution systems. The paper will present general considerations, common definitions, and redundancy methods in distribution systems across various utility and industrial installations in North America.

Review of the redundancy practices and their economical and philosophical backgrounds in distribution systems will help understanding of the main objectives. The paper will also outline in detail advantages and disadvantages of redundancy considerations such as separate DC power supplies, dual trip coils, separate trip circuitry, Main/Backup (or SET A/ SET B) protection concepts, redundant feeder controls, alarms and indications, and finally redundant communication channels.

This paper will present a case study for typically used redundant schemes and demonstrates some common implementation errors, pseudo redundancy, and illustrations of two relays providing inadequate redundancy. Lastly, the paper will elaborate on some of the redundancy issues and their solutions based on new generation microprocessor relays, such as multiple setting groups, automatic reclosing and breaker failure protection cross-initiation, oscillography cross-triggering, etc. The intention of this paper is to initiate an industry-wide discussion and idea sharing on the subject of redundancy and implementations in the utility and industrial applications.

2. Overview Of Redundancy

2.1 Definition of redundancy

The goals of any protection and control system are to isolate a specific section of the system when an intolerable condition is detected, to minimize the duration of, and to limit the impact of, this abnormal condition. This is accomplished by having a reliable protection system, one that is both dependable and secure. These general principles apply to all parts of the protection system, including the medium voltage distribution system.

However, to meet the requirements of dependability and security, the primary protection system for any zone should operate within the expected time to clear a fault. The traditional method of maintaining reliability of the medium voltage distribution system is to use time-coordinated backup protection. In this case, the zone of protection for the back up relay overlaps that of the primary relay and clears the fault after the pre-defined time delay allocated for the normal operation of the back up relay. However, operation of a backup relay is undesirable as the backup protection is usually slower than the primary protection and it can isolate a larger part of the distribution system. Therefore, operation of the backup protection may be considered a degradation of security.[1] The focal point of this discussion is on a method that maintains the correct operation of the medium voltage distribution protection using redundancy of elements to eliminate single points of failure. This discussion is focused on modern microprocessor relays that are dominating new installations, while providing more functionality for the system than just traditionally accepted overcurrent protection. Electromechanical feeder relays are inherently redundant for their overcurrent function, but they do not provide redundancy for other protection or control functions. This discussion on redundancy is built on the following definitions:

Redundancy: The protection and control system uses elements in parallel to maintain correct normal operation of the protection and control system if one critical element is not operating. Redundant elements are therefore parts of the primary protection for a specific segment of the distribution system. Redundancy should improve system reliability by maintaining both dependability and security.

Backup: Backup functions maintain the dependability of the total protection system during incorrect operation of the primary protection. Backup functions are not part of the primary protection for a segment of the distribution system and maintain dependability at the expense of security.

Availability: A protection system is available when all functions necessary for isolating a fault for a specific zone of protection within the desired operating time are operating normally. Redundancy therefore increases reliability by ensuring the protection system is available to protect a specific piece of the system.

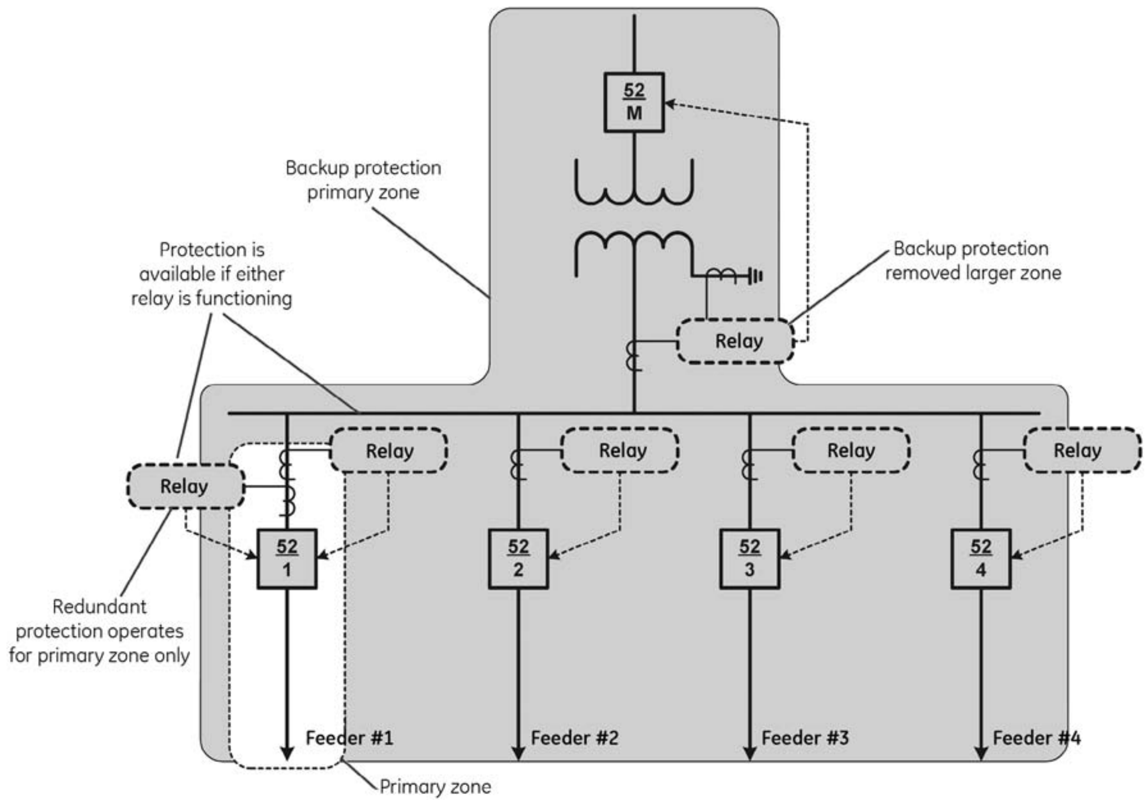

Figure 1.
Redundant Protection and Backup Protection

In Figure 1, Feeder #1 is the only feeder with relay redundancy. As long as one of the two relays protecting Feeder #1 is operating, the protection for Feeder #1 is available. The transformer overcurrent relay is the backup relay for any of the four feeders. If the protection of one of the feeders is unavailable, the backup relay will operate for a fault and will isolate a larger part of the distribution system than just the faulted feeder.

2.2 Expectations for Redundancy

The general benefits of redundancy are the same for transmission systems, medium voltage systems, and generator systems. Redundancy increases the availability of the protection and control system, thus enhancing the overall reliability and power system stability during fault conditions. This in turn can also keep the power quality at an acceptable level and reduce the operating costs.

The key goals of redundancy for power system protection and control are to maintain the overall reliability, increase dependability, add system availability, enhance operational flexibility and to reduce the overall costs. It is very rare that a short circuit event on the distribution system will impact system stability. However, the key consideration may be the performance of the distribution system as part of a load shedding scheme. Maintaining power quality at a high level is achieved by quickly isolating a fault, so this is a direct reflection on the reliability of the protection system.

The more significant reasons for implementing redundant protection for medium voltage distribution systems are to improve or maintain the overall power system reliability by increasing the availability of the protection and control system, and to reduce operating costs for the protection and control system.

A reliable distribution protection system is defined as being dependable and secure. However, the reliability of the distribution system is generally defined by a measured reliability index, such as the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). Utilities usually have some performance incentive from regulatory bodies to maintain the SAIDI and SAIFI indices at a certain level. Failure of a protection element does not directly have an added impact SAIDI and SAIFI. However, operation of a backup protection to clear a fault event usually has an added negative impact on the reliability indices. Consider a temporary fault on Feeder 2 in Figure 1. This fault should be cleared by the opening and reclosing of the circuit breaker by the primary protection of Feeder 2, and will not negatively impact SAIDI or SAIFI any more than the normal impact for each particular event. However, if the relay on Feeder 2 is failed, the backup protection on the transformer will operate and cause an outage to the entire load connected to the bus. This fault then becomes a measurable service event affecting more customers than just the faulted feeder thus an added impact on the SAIDI and SAIFI indices and the overall distribution system reliability.

A redundant protection and control scheme then improves the reliability of the distribution system by increasing availability of the protection and control system, limiting the possibility of an incorrect operation which could significantly impact SAIFI and SAIDI.

Redundant protection will increase the initial installed cost of the distribution system protection system. However, a well-designed redundant scheme should decrease the total operating cost by providing operations flexibility and reducing extensive outages due to incorrect protection operations. Operations flexibility allows a protected feeder to remain in service with one set of redundant protection out of service. This simplified maintenance by allowing routine testing of one set of protection with regular primary protection still in service. Also, operational flexibility allows the investigation of a failed relay to be part of a planned maintenance schedule, as opposed to an expensive unplanned service rollout. A highly available protection system also reduces the need for fault investigation and service restoration due to the operation of a backup relay by substation personnel, as opposed to investigation of routine feeder faults by distribution service personnel.

Another driver that cannot be overlooked is compliance with the redundancy criteria or performance requirements mandated by regulatory bodies such as NERC, NERC regional Coordinating Councils, and the States Public Utility Commissions.

In addition, the costs due to a previous failure of the protection system may justify implementing redundancy across the system.

It can be argued that the probability of a mis-operation is increased as a redundant relay is added to the scheme. However, a careful design and use of different operating principles for the desired relay function can eliminate or minimize this probability.

One key fact cannot be overlooked: if the goal of redundancy is to increase reliability, the impact of redundancy must be measured in terms of performance and costs. A system for measuring distribution protection system reliability, similar to methods implemented on transmission protection systems[2] is more meaningful to protection engineers than SAIDI or SAIFI indices. Such a system differentiates between correct and incorrect relay operations, and provides some good information on general root causes of the incorrect operations of the protection system.

Therefore, the chief expectation of redundancy is to improve the reliability of the distribution system by increasing the availability of the protection system. The design of a redundant system must focus on simplicity, ease of engineering, training, and operational requirements. Any redundant system must provide the flexibility to operate the distribution system as efficiently and risk free as possible, and provide the ability to adapt to specific application requirements.

3. PG&E Approach to Redundancy in Distribution Networks

PG&E uses redundant sets of protective relaying schemes on both the Transmission and Distribution lines. For bulk transmission lines, PG&E follows the mandated/suggested criteria by NERC and WECC. The main objective of PG&E's philosophies, aligned with the NERC/WECC criteria, is to eliminate or at least minimize the possibility of a proactive "scheme failure" resulting from a "single component failure".[3]

PG&E's philosophy on redundancy also applies to operating principles of the protective relays or schemes and to the manufacturers and suppliers. As a general rule, it is preferred that the redundant relays or schemes be from different manufacturers and operate on different principles for the same function. The rationale for using different manufacturers is to safeguard against possible bankruptcies and business closures. Use of different operating principles is to increase dependability of the relaying function under a situation where a particular operating principle may be insensitive to a certain fault condition. As a general rule this philosophy provides added assurance for proper operation of the protective schemes in the event of any undetected design flaws in the relays of any one manufacturer.

The following subsections discuss PG&E's main objectives on the redundancy requirement and the salient points of the redundancy criteria for all electrical systems.

3.1 PG&E Objectives for Redundancy

PG&E's redundancy requirements are intended to accomplish the basic objectives of enhanced functional dependability, increased scheme and equipment availability, and added operational and maintenance flexibility.

Enhanced Functional Dependability

Schemes or relaying systems with sufficient level of redundancy have a higher degree of dependability. If one relay or relaying function fails, the redundant system is expected to work properly. In general and as well as in a probabilistic sense, it is unlikely for both systems to fail at the same time. Total failure in a protective scheme could be catastrophic and thus the enhanced dependability is highly desirable.

Increased Scheme/Equipment Availability

It is easy to see that any protective "Scheme" with redundant components has a higher degree of availability as compared to the scheme without redundancy. The "Equipment", such as a machine or a transformer, protected by a scheme with sufficient redundancy also has a higher degree of availability. With the failure of one set of protection in a redundant scheme, the protected equipment can remain in service. Without redundant protection, the equipment will be out service upon failure of its protective scheme. There are many proposals to initiate tripping of the protected equipment upon a single relay or protective scheme failures. However, depending on the importance of operation for each case, economical analysis should be conducted considering the following question. "Is it more economical to pay the added initial cost (mainly labor costs!) to have the equipment available, or to bear the down time cost of the equipment when it's protection has failed?" Despite the fact that examples of economic analyses considering the above question is unavailable at this time, it is conceivable that fully redundant systems may be economically justifiable for many cases.

Added Operational/Maintenance Flexibility

Schemes with redundant components are inherently more flexible for maintenance and/or testing. Each of the redundant relays or devices maybe taken out of service for routine maintenance or testing, while the scheme is still in operation. This flexibility is especially desirable operationally for clearances, as the operators may be allowed to take a relay or device out of service without any need for installation of temporary protective devices. Again, it should be noted that maintenance flexibility might also be economically justifiable for many cases.

3.2 Salient Points of the WECC Redundancy Criteria

The following distinct points about redundancy are being considered by NERC, WECC, and PG&E. Although the criteria are proposed for application on bulk transmission systems, the majority of the concerns also hold for sub-transmission and distribution systems. PG&E uses these criteria as guidelines when developing the distribution protection systems.

3.3 Relaying Systems

At least 2 sets of relaying system are required to provide the same relying functions independently. The design objective is to eliminate or minimize the risk of simultaneous failures in both systems.

Taking the simple case of Phase and Ground Overcurrent relaying functions for a Distribution feeder, the "Relaying System" redundancy maybe accomplished by either or the options:

Option 1: Three single function (overcurrent in this case), single phase relays and a 4th single function ground overcurrent relay. This has been a PG&E standard for distribution feeder overcurrent protection using electromechanical relays for years. It can be seen that in this configuration, every phase (or ground) overcurrent function is redundant. Adequate phase and ground overcurrent feeder protection is maintained even if any single relay is removed from the scheme for any reason (maintenance or failure).

Option 2: Two multi function (capable of both phase and ground overcurrent functions in this case) 3 phase relays. Each of the 3 phase multifunction relays may be taken out of service (maintenance or otherwise) without jeopardizing phase and ground overcurrent protection of the feeder.

3.4 Current Transformers (CTs):

AC Current sensing for the 2 redundant relaying systems should be supplied from 2 independent sets of CTs. This is to safeguard against "over tripping" or "lack of tripping" associated with current circuitry failures, CT saturation, etc. PG&E's new designs for distribution feeders include separate CTs for this purpose.

3.5 Voltage Transformers (VTs):

AC Voltage sensing inputs to the 2 redundant relaying systems should be supplied from 2 independent sets of VTs. This is to safeguard against relaying problems associated with VTs, fuses, or other failures in the potential circuitry.

3.6 Power Supplies:

DC circuits for controls and power supplies for protective devices should come from separate DC circuit breakers. This is so that the system can operate despite loss of a single DC source.

3.7 Breaker Failure Schemes:

Although breaker failure schemes need not be redundant, local breaker failure schemes should be installed. Each of the redundant relaying systems should independently initiate the breaker failure function as needed.

3.8 Communication Systems:

The communication channels for pilot schemes also need to be redundant if the communication aided tripping is deemed as the primary means of protection or needed for system performance. For bulk transmission systems the communication channels must also meet the performance requirements set by the WECC.[4]

3.9 Breaker Trip Coils:

Circuit breaker for Extra High Voltage (EHV) and Ultra High Voltage (UHV) systems (referring to 345 kV and above) should be equipped with dual trip coils. Each of the relaying systems should initiate tripping to both of the breaker's trip coils.

Note that the extra sets of VTs, communication systems, and the dual trip coils requirements are predominantly intended for bulk transmission lines. These criteria are less likely to be mandated for sub transmission or distribution systems.

4. Implementing Redundancy

PG&E has made specific decisions about how to proceed with redundancy on the medium voltage distribution system. Before specifically looking at the PG&E solution, an overview of the functions and equipment that can be made redundant and their benefits may be useful.

4.1 Equipment Considerations for Redundant Protection

Every piece of equipment for feeder protection can be made redundant, except the busbar and the circuit breaker. Figure 2 shows a simplified version of a combined AC and DC schematic for a typical feeder circuit. Redundant equipment can be installed for all protection functions, control functions, contact outputs, CT and VT circuits, the battery system, and the breaker trip coils. However, the correct choice of equipment must be based on company operating philosophy and history, the expected benefit to system reliability, and the cost of implementation. Table 1 briefly describes some issues around redundancy of each function.

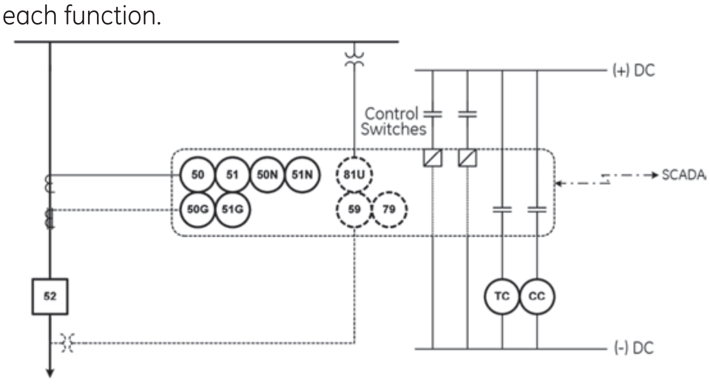

Figure 2.
Feeder AC and DC schematic (simplified)

Function	Comments	Impact on reliability
Short Circuit Protection	Completely redundant primary protection ensures tripping for faults. Simple to implement. High impact on availability. Can be expensive depending on implementation	High
CT and VT	Provides a completely redundant measurement quantities for use with redundant relays. Some impact on reliability, as CT and VT circuits are considered very reliable.	Medium
Station Battery	Ensures control power for redundant microprocessor relays and lockout relays and trip coils. Simple to implement, good impact on reliability. Expensive relative to other costs in an MV substations	Low
Trip Coil	Ensures operation of circuit breaker. Allows breaker failure re-trip. Expensive on MV breakers, especially to retrofit.	Low
Trip and Close Contacts	Ensures operation of circuit breakers against relay contact failure by providing multiple control paths. Simple and inexpensive to implement, little impact on reliability.	Low
Control Switches / Local HMI	Ensures local control of circuit breaker. Can be confusing to operations personnel, expensive to implement. No impact on reliability.	Low
Automatic Control Functions	Ensures reclosing, load-shed, and similar functions are available. Operationally difficult to implement in more than one relay due to concerns on the priority of operation. Successful implementation will increase reliability by restoring service.	Medium
SCADA Communications	Ensures remote control of circuit breaker. Can be confusing to implement through multiple relays. Some impact on reliability.	Low

Table 1.
Considerations for Functional Redundancy

4.2 Choosing Functions for Implementing Redundancy

Table 1 discusses the common protection and control functions applied on a distribution feeder, the benefits on reliability of providing a redundant function, and the general impact on reliability of the protection and control system. In this table, the impact on reliability is based on some general assumptions on the operation of the system if a specific function fails, the likelihood that it will fail, and on the efforts and challenges involved to implement a redundant solution. Since these are general recommendations, the challenge for the utility engineer is deciding on when to provide redundant functions. To make this decision, there must be some information on the likelihood of such an event occurring, an understanding of the cost to provide redundancy, and a methodology to measure the improvement in the performance of the distribution system.

To look at the decision making process, consider a simple example of circuit breaker trip coils. A specific utility experiences 1 trip coil failure for every 100 breaker operations. The two obvious solutions to this high rate of failure are to increase the maintenance of the circuit breakers, or to install dual trip coils on every circuit breaker. There are two analyses to make. One analysis is to determine the improvement in reliability for each course of action. This analysis may require field trials to truly determine the efficacy of an individual solution. The second analysis is the cost to implement each method.

For most of the functions on a typical distribution feeder, such as CT circuits and breaker trip coils, the actual process to provide a redundant function is well understood. However, many of the control functions are dependent on the decision made for redundancy of the basic short circuit protection functions. The first step is then to look at the options for redundancy of short circuit protection.

4.3 Methods to Implement Redundant Protection

Protection functions are made redundant by simply adding more relays for the primary zone of protection. These schemes must be carefully implemented to prevent mis-operations from

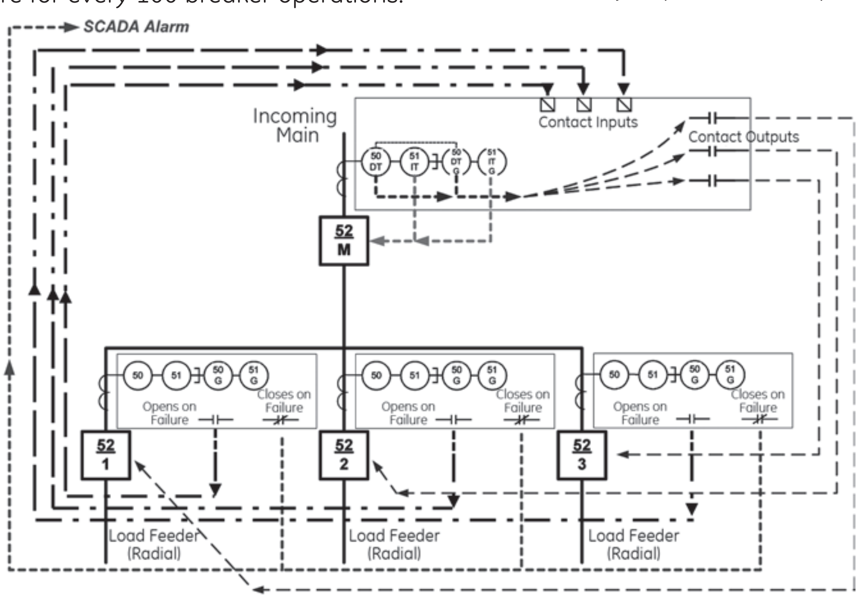

Figure 3.
Accelerated Backup Scheme

occurring during both in-service and maintenance conditions. There are several methods available for supplying redundant protection, depending on the relays selected for use, the need for additional functions in the relay, and the ease of implementation. The general methods for redundant relaying in this discussion are accelerated backup protection, dual redundant (Set A/Set B) relay protection, feeder relay pairs, and using one relay with multiple current sources or provide relay redundancy.

4.4 Accelerated Backup

An accelerated backup relay scheme makes use of an existing transformer or bus overcurrent relay to provide redundant protection for a feeder relay that is out of service. This example of Figure 3 uses a bus overcurrent relay, but the principle for using a transformer overcurrent relay is identical.

During normal operations, the bus overcurrent relay controls only the main "M" breaker. The overcurrent elements are set to trip on some level of current that is above the maximum load of the bus and these elements must pickup and time coordinate with each feeder relay. In the accelerated backup scheme, the failure of a feeder relay, or a feeder relay being removed from service, changes the tripping sequence of the bus overcurrent relay.

The failure of a feeder relay is signaled to the bus overcurrent relay by the feeder relay service contact. The bus overcurrent relay then changes its tripping sequence so that high-speed tripping elements, such as the phase and ground definite time overcurrent elements, control the circuit breaker associated with the failed feeder relay. Time-delayed tripping elements, such as the phase and ground inverse time overcurrent elements, control the main bus breaker as per normal application. The pickup settings of the bus overcurrent relay do not change. With a failed feeder relay, the bus relay always trips the associated feeder breaker at high speed, even if the fault occurs on a feeder with a healthy relay. Therefore, an accelerated backup scheme is best implemented in conjunction with a reverse interlocking bus protection scheme. The pickup of a healthy feeder relay blocks the high-speed tripping of the feeder breaker.

The bus relay will only see faults relatively close in on the feeder, so this scheme does not provide completely redundant protection for a failed feeder relay. Also, when implemented in conjunction with reverse interlocking bus protection, this scheme slows down the bus protection for a failed feeder relay. However, accelerated backup is applied because this is a very cost-effective solution. The feeder and bus relays already exist for primary protection purposes, and the accelerated backup scheme only requires some additional control circuit wiring to put into place

4.5 Dual Redundant Relay Protection

Dual redundant relay protection uses two feeder relays for each feeder circuit. This method provides complete redundancy of short circuit protection as shown in Figure 4, and can provide complete redundancy of control functions, metering, and communications, depending on the specific implementation. One typical implementation is to use a full-featured feeder management relay that includes protection, metering and control functionality in combination with a less expensive feeder relay that provides only short circuit protection. PG&E has standardized this option for all new distribution feeder installations [5]. Another option is to use two feeder management relays that have similar capabilities in protection, metering, and control, in a Set A / Set B combination similar to what is typical of transmission protection systems.

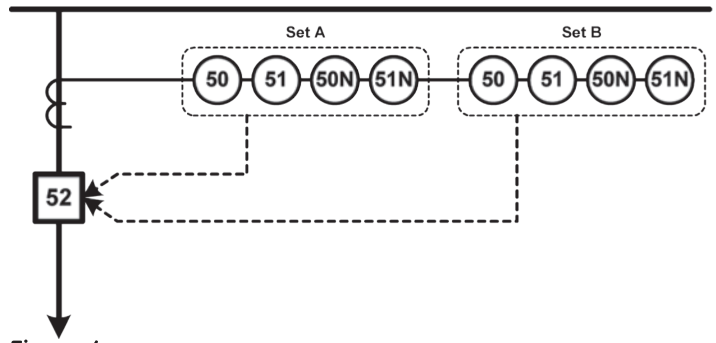

Figure 4.
Dual Redundant Relay Protection

There are many considerations when choosing the relays to implement dual redundant relay protection. With every choice, this scheme increases the availability of the protection system. The cost can be fairly high, depending on the relays chosen to implement the scheme. This scheme can be applied when feeder relays are mounted in the circuit breaker low voltage compartment in a relay control house, or on switchgear.

4.6 Feeder Relay Pairs

Accelerated relay backup schemes are cost-effective, but do not provide completely redundant protection. Dual redundant relays do provide completely redundant protection, but can be expensive. Some modern microprocessor relays have multiple sets of three-phase and ground current inputs, with independent overcurrent protection for each set of current inputs. This allows one relay to be the primary protection for one feeder and the redundant protection for a second feeder, as shown in Figure 5.

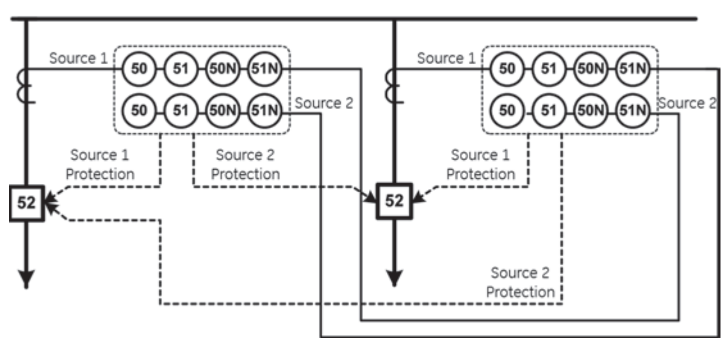

Figure 5.
Feeder Relay Pairs

Therefore, with feeder relay pairs, 2 relays can protect 2 feeders with complete redundancy, for the cost of one standard protection package. This application is very practical when relays for all feeder circuits are located in a central location, such as a switchgear lineup or control house. This application is less practical when the relays are located in individual circuit breakers due to the increased wiring costs. Also, using feeder relay pairs typically only provides redundant functionality for short circuit protection, not control functions.

The concern with feeder relay pairs is on the operations side. One relay accepts current (and possibly voltage) measurements from two different sources, which may be confusing to operations personnel. This scheme also requires careful procedures during testing and maintenance. Both CT circuits must be shorted and the trip circuits to both breakers must be blocked. However, this scheme does permit complete protection of both feeders while performing maintenance on one of the feeder relays.

4.7 Multiple Source Feeder Relay

Certain microprocessor relays can accept up to 6 separate three-phase and ground current inputs and provide independent overcurrent protection for each of these inputs. This can be another cost-effective method to add redundant overcurrent protection, as one additional relay can provide redundant overcurrent protection for a small distribution substation or switchgear lineup. This method is illustrated in Figure 6. Some disadvantages to this system are complexity and the high degree of dependence on the relay with multiple inputs.

It is also possible to use 2 such relays to provide Set A and Set B redundant protection for up to 6 feeders, as shown in Figure 7. Either variation of the multiple source feeder relay redundant protection easily provides redundant protection for all feeders.

Once again, this type of application is very practical when relays for all feeder circuits are located in a central location, such as a switchgear lineup or control house. This application is less practical when the relays are located in individual circuit breakers due to the increased wiring costs.

The multiple source feeder relay used for redundant protection provides a simpler maintenance option than using feeder relay pairs. It is very clear that each feeder has 2 separate relays protecting the feeder, with clearly delineated protection functions and trip circuits.

4.8 Redundancy of Control Functions

Control functions, such as reclosing, voltage supervision, load shedding, and local and remote control, are not commonly made redundant. This is in part because a redundant control scheme improves system reliability very little and can be expensive and time-consuming to implement. In addition, this can lead to a confusing control hierarchy, with the resulting chance for error and unintended operations.

A traditional control scheme uses a remote terminal unit (RTU) in conjunction with relays, in part due to the limited control capabilities of the relays. The RTU provides remote control and may provide such functions as load shedding and restoration. The relay provides some control functions, such as reclosing. However, modern microprocessor feeder relays have significant control capabilities and in many applications are the centerpiece of control for a feeder breaker. The possibility of providing redundant control in a reliable and affordable fashion, is much more likely in these relays. For example, in a dual redundant relay application with Set A and Set B relay, the Set A relay can be the normal local control relay for the circuit. The Set B relay can have similar local control functionality that is disabled while the Set A relay is in service and is automatically enabled when the Set A relay is out of service. The implementation of control functions in Set A and Set B relays requires careful consideration of the different control functions to provide a solution that works as intended.

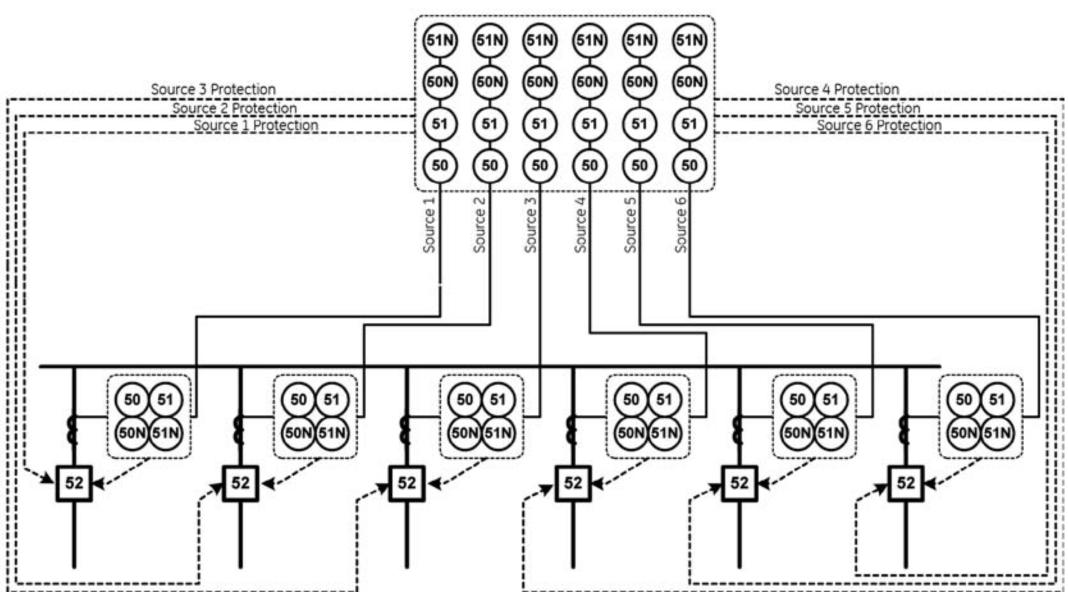

Figure 6.
Multiple Source Feeder Relay

5. PG&E Redundant Protection And Control System

Pacific Gas & Electric has previously presented a paper on the Integrated Protection and Control (IPAC) standard protection scheme for medium voltage distribution feeders.[5] This paper describes the total operational benefit of the IPAC system for PG&E, including reducing capital, maintenance and operating costs, increasing the information available from a substation and more tightly integrating SCADA. One of the business and technological goals of the IPAC system is the need to improve system reliability and at the same time to decrease the service down time for greater customer satisfaction.

The IPAC system is specifically designed in terms of reliability, to meet the WECC and NERC requirements for redundant protection. The protection portion uses a dual redundant scheme, implemented in 2 feeder management relays.

All of the basic protection functions are implemented in both the Set A and Set B relay, including directional control of overcurrent functions, undervoltage protection, and overvoltage protection. The decision to make these voltage-based functions redundant almost certainly requires a dual redundant system. The IPAC system also uses independent sets of CTs for the Set A and Set B relays. This increases the overall availability and reliability of the system for the cost of inexpensive medium voltage rated CTs.

Implementing redundant protection functions is the simple part of the IPAC system. In keeping with the goal of eliminating, or limiting the impact of, a single point of failure, other parts of the IPAC system are split between the Set A and Set B relays. Most of the control functions, including reclosing, breaker failure, underfrequency load shedding and local control operations, are provided in the Set A relay. The Set B relay is responsible for SCADA communications and remote control of the distribution feeder. In addition, the Set A relay monitors key equipment, such as the breaker contact wear, breaker trip circuit, and VT circuit. This equipment is either impractical to duplicate, or too difficult or costly to make redundant. This type of monitoring information, however, can help maintain the reliability of the feeder by providing information to guide the Reliability Centered Maintenance (RMC) programs.

The split of local control operations and remote control operations between the Set A and Set B relay is intended to provide demarcation between local and remote control of the feeder. This simplifies the scheme for operations personnel and simplicity helps maintain reliability. Splitting control between the two relays complicates the design and engineering of the original system, and requires substantial contact input / contact output communications wiring between the two relays. Careful consideration of the integrated control is necessary to ensure successful operation of the feeder. A review of the overall issues and logic for cut in / cut out switches, setting group synchronization, and reclosing initiation will illustrate some of the challenges.

5.1 Cut In / Cut Out (CI/CO) switches

A key challenge for the IPAC system is to maintain the Set A and Set B relays in a common operating state. Through local and remote controls, it is possible to Cut In and Cut Out (CI/CO) reclosing, cut in and cut out neutral overcurrent protection, cut in and cut out the Set A and Set B relay and change the setpoint group of each relay. For example, consider the CI/CO switch to enable and disable reclosing. The local control is through a pushbutton on the Set A relay and remote control is through SCADA command through the Set B relay, communicated to the Set A relay through hardwired outputs and inputs. However, the scheme must be reliable even in the face of abnormal situations, such as:

1. If a relay fails or intentionally taken out of service, the out of service relay status must be communicated to the in-service relay in order to block commands issued by the abnormal relay and prevent accidental operation of the CI/CO function of the in-service relay.
2. If a relay cycles the control power, all the virtual CI/CO switches must be restored to the pre-fault states. All the commands issued by the restarting relay must be ignored by the in-service relay.
3. Prior to restoration of a relay previously taken out of service for maintenance, it is required to match manually all the states of the virtual switches to the states of the corresponding switches of “in-service” relay.
4. The duration of the switching command must be at least 50 milliseconds in order to prevent false operation of the function due to the contacts bouncing. This operation time delay is also utilized in the logic to block the incoming command issued by the partner relay during power loss event.

A generic view of this logic is in Figure 9.

5.2 Setting Group Synchronization

The IPAC system uses multiple settings groups for different operating scenarios. These settings groups must be synchronized while both relays are in service. Settings groups can be changed locally through pushbuttons on the front panel of the Set A relay and remotely via SCADA command issued through the Set B relay. The simplified logic for the coordination between the Set A and Set B relay is shown in the block diagram of Figure 10.

The logic behind this scheme was previously described in [5]. The biggest challenge to this implementation is addressing the setting group selection behavior when a relay powers up after being removed from service. Both the Set A and Set B relays store the active setting group in non-volatile memory. When either relay is powered up, the relay attempts to synchronize the setting group to the Set B active setting group. If the Set B relay is not in service, the Set A relay will restore the active setting group stored in its non-volatile memory.

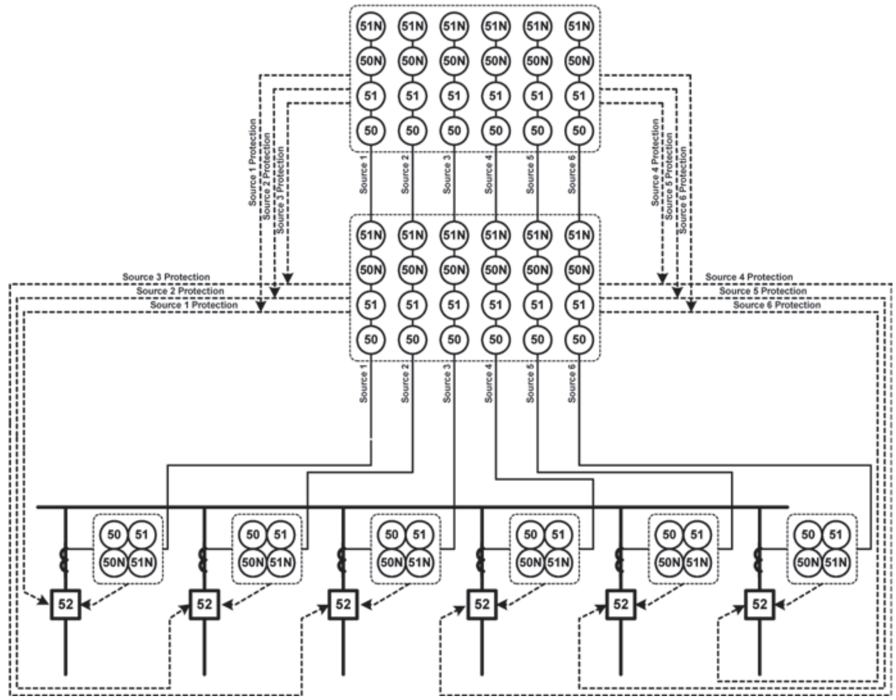

Figure 7.
Multiple Source Feeder Relay as Set A / Set B

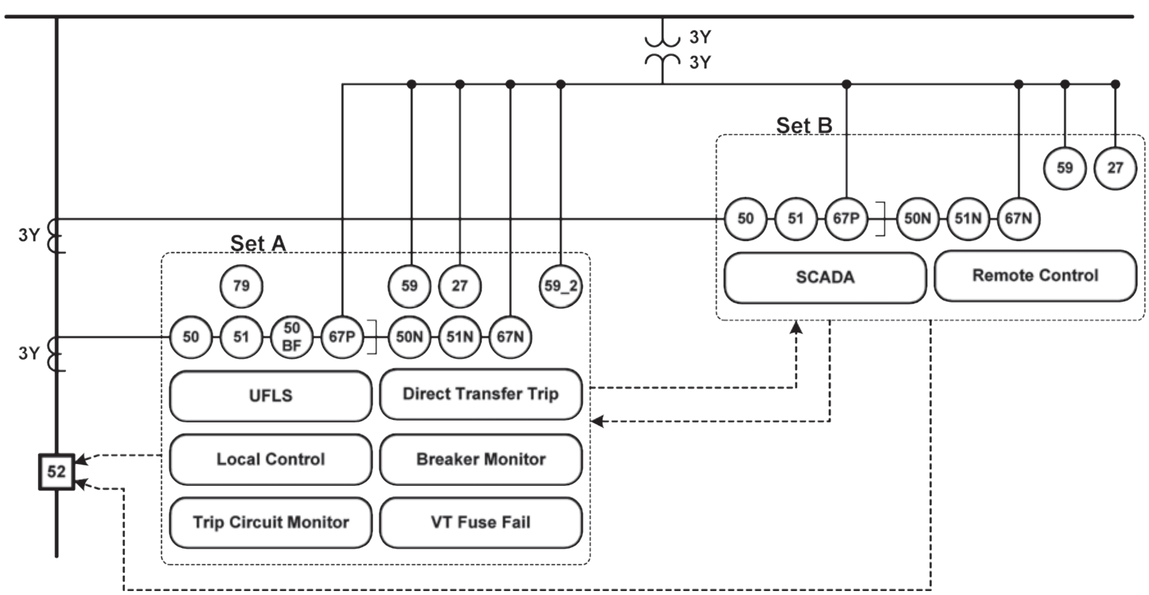

Figure 8.
IPAC System Redundant Protection

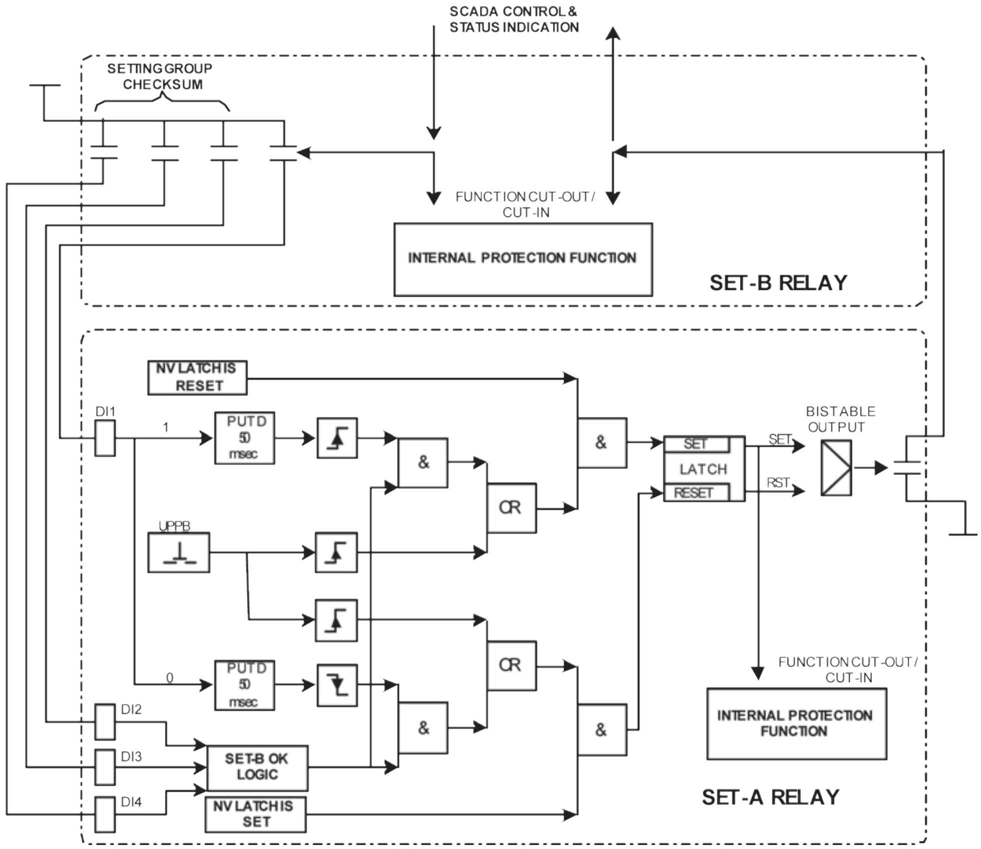

Figure 9.
Generic Cut In / Cut Out Switch Logic

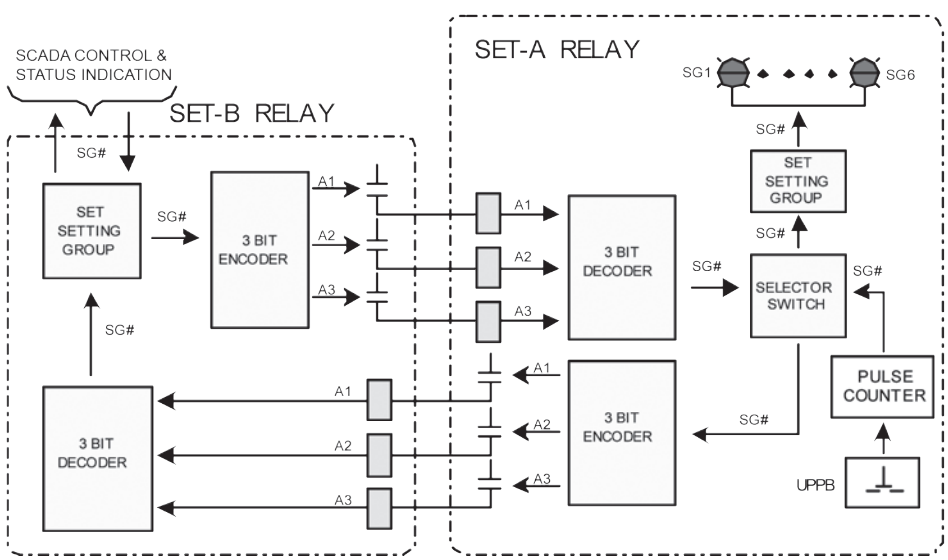

Figure 10.
Setting Group Simplified Block Diagram

5.3 Reclosing Initiation

PG&E uses a sophisticated reclosing scheme in the IPAC system. Automatic breaker closing may be initiated for any of the following reasons:

- Feeder restoration after a transient fault
- Restoration after recovery of the system voltage
- Restoration after recovery of the system frequency

Reclosing is initiated every time the circuit breaker makes a transition from the closed to an open state, unless some condition (such as a manual breaker trip) explicitly blocks reclosing. This scheme also includes a "stall" function, to temporarily disable the reclose function in progress due to abnormal system conditions such as no bus voltage, or a negative sequence overvoltage condition that indicates a loss of phase situation. Because of these requirements, the IPAC system uses the flexible programming capabilities standard in the relay to implement a customized automatic reclosing logic. This logic is more completely described in [5]. Due to the complexity of this logic, and the need to keep a control hierarchy, reclosing is kept exclusively in the Set A relay.

5.4 Other Functions to Improve Reliability

The IPAC system takes some direct steps to maintain the availability of protection and control functions. Beyond redundant protection functions and demarcation between control functions, the IPAC system performs some basic monitoring functions with the goal of detecting incipient problems before these problems negatively impact the operation of the feeder. Trip circuit monitoring is implemented in the Set A relay to measure the continuity of the trip circuit, including output contacts, wiring, and breaker trip coil. The trip coil monitor alarms on any abnormality in the trip circuit, to allow maintenance personnel to resolve the problem before the breaker is called upon to operate.

Another interesting monitoring function is the slow breaker maintenance tool. This tool is programmed in the Set A relay, and monitors the travel time of the main breaker contacts during breaker open and close operations. If the actual operating time exceeds a reference time, a slow breaker operation is declared, and alarms sent to maintenance personnel.

While not directly redundant protection, these simple monitoring tools may keep aging or failing equipment from causing incorrect operations of the protection system.

6. Summary

The major goal of redundant protection and control for medium voltage distribution feeders is to increase the availability of the protection system. Careful consideration is needed when implementing redundant functions to ensure that redundancy actually improves reliability.

There are many methods to implement redundancy. The case study presented in this paper is the PG&E IPAC system. PG&E implemented the IPAC system as the new and redundant protection and control standard for medium voltage distribution feeders. The main objectives have been to improve the total reliability of the system while lowering the capital, maintenance, and operating costs for distribution feeders. The primary design criteria have focused on enhanced dependability, increased availability, operational flexibility, and to ensure the primary protection always operates for faults. Efforts have also been extended to lower the installation and maintenance costs and to minimize risks during testing and repairs. To meet these design criteria, the IPAC system provides:

- Completely redundant protection functions for short circuit and voltage-based protection.
- Clear demarcation between local and remote control of the distribution feeder.
- Integration between the Set A and Set B relay to properly execute control functions and synchronize settings.

PG&E has installed about 350 IPAC units on its distribution system during the course of past 3 years. The average unit cost has been in the neighborhood of $12,000.00. The most evident benefits have been integrated protection, control, metering, and ease of installations. The major challenges so far have been training of personnel, dealing with rapid software/firmware updates in microprocessor relays and lack of SCADA in many substations.

PG&E expects to meet its goals in terms of system reliability and improved costs. However, the IPAC system is relatively new and PG&E does not have enough field data as of yet to document the actual improvement in reliability, or improvements in cost. The success of any implementation of redundancy can only truly be determined by measurable improvement in performance.

7. References

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Application of Phasor Measurement Units for Disturbance Recording

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1. Introduction

This paper looks at the specific application of Phasor Measurement Units (PMUs) for disturbance recording, with a special emphasis on wide area cross-triggering of recording PMUs during events. Disturbance recording, or long-term recording of phasor data, provides valuable information when analyzing wide area disturbance and power swings in the utility system. The newly approved NERC PRC-002 and PRC-018 standards require the installation of disturbance recording equipment at strategic points on the power system. The value of this equipment is only realized when discrete records are captured simultaneously at all points on the power system, to provide a complete snapshot of a specific event. Traditional recorders rely on local triggers to capture the data, however, an individual recorder may not trigger for a specific event, or may trigger in a different time frame than other recorders on the system and not capture valuable data. A practical challenge is adding the disturbance recording function to existing substations and relay systems.

Ongoing projects, such as the Eastern Interconnect Phasor Project, promote the installation of PMUs to provide real time measurement of the state of the power system, by streaming highly accurate synchrophasors at a high sampling rate. The PMUs are generally installed at the same strategic substations that require disturbance recording. In addition, today's digital relays (such as a line distance relay or current differential relay) are capable of synchronous phasor measurements. In addition to streaming data to a centralized database, PMUs may have the ability to record data at the PMU based on local trigger conditions. The record may include synchrophasor data as well as additional analog values and digital status. This recorded data meets the disturbance recording requirements set by NERC. The paper discusses the applicability of synchrophasor data to disturbance recording and the capabilities of PMUs to capture the appropriate data.

This paper also discusses practical aspects of using the IEEE Synchrophasor standard communications in conjunction with IEC61850 communications for wide area cross-triggering of PMUs. Also discussed are communications channels requirements and expected performance of cross-triggers. Other disturbance recording applications exist in the industrial domain, such as motor starting failure events on large motors. Synchronized measurements provide the ability to correlate the failure with other events in the industrial process. This paper will discuss industrial applications of PMUs.

2. Phasor Measurement Units and Recording

In the context of this paper, disturbance recording is defined as recording of phasor or RMS values of data over a long period of time. Disturbance recording is intended to show the response of the power system and equipment due to power system faults, such as an out-of-step condition, as opposed to power equipment faults, such as a short circuit. The time interval for these "long term" events can range from 1 second (in the case of a fault and high-speed reclose) to many minutes (in the case of system oscillations). The fast sample rates (30 to 60 phasors per second) of today's synchrophasor-based disturbance recording devices can be used to analyze both power system faults and the more traditional power equipment faults. The term Dynamic Swing Recorder (DSR) is also often used to describe a device that captures disturbance data over a long period of time. A more complete description of these terms is available in [1].

NERC has issued Standard PRC-002-1 entitled: Define Regional Disturbance Monitoring and Reporting Requirements. Section R3 specifically addresses criteria for dynamic disturbance recording, including location of recorders, electrical quantities to record, recording duration, and sampling rate. The NERC standard essentially states that DSRs are to be situated at key locations, are to record voltage, current, frequency, megawatts and megavars for monitored elements and are to record the RMS value of electrical quantities at a rate of at least 6 records per second.[2]

The Regional Reliability Councils (RCCs) of NERC are responsible for refining these standards for a specific operating region. By reviewing the standards as interpreted by some of the RCCs, it is possible to provide a good overview of disturbance monitoring requirements.

> **Location of DSRs**. DSRs are to be located at key substations for the power system. Key substations are generally defined as transmission substations with significant connected generation, large transmission substations (containing 7 or more transmission lines), transmission substations that interconnect to another regional authority or company, at major load centers (such as load centers greater than 2500 MW), or where undervoltage load shedding schemes are implemented.

Electrical quantities to record. The NERC requirement is to record voltage, current, and frequency, with the ability to derive or record megawatts and megavars for each monitored element. The minimum requirements defined by the RCCs are:

- Bus voltages: at least one three-phase measurement per voltage level, with two measurements per voltage level recommended
- Frequency: at least one frequency measurement for every voltage measurement
- Three-phase line currents for every critical line
- Megawatts and megavars, three-phase, for each monitored line.

Record length. Disturbance recording, and DSRs, are intended to capture longer term power system faults. DSRs therefore require longer record times. The recording length is typically specified as 90 to 180 seconds, including 30 seconds of pre-fault data. DSR records may be required to automatically extend in length when additional triggers occur during recording.

A second option for record length is to use continuous recording. A DSR therefore always captures data for all analog channels and typically stores the last 30 days of data. The challenge with continuous recording is to manage the large amounts of data. Also, it is important to be able to retrieve the key pieces of the data to analyze an event.

Triggers. Triggers are necessary to initiate recording for the typical DSRs that have a discrete record length. For continuous recording, triggers provide markers into the key pieces of data during an event. The ability to "share" triggers between multiple sites is also necessary in order to capture a wide-area view of an event.

There are many types of triggers available in DSRs, including:

- Magnitude triggers, on voltage, current, frequency, real power, reactive power and apparent impedance
- Rate-of-change triggers, on voltage, current, frequency, real power, reactive power and apparent impedance
- Harmonic content triggers, on a specific harmonic frequency, or on total harmonic distortion
- Delta frequency triggers
- Contact triggers, such as breaker operation or communications channel operations
- Symmetrical components trigger.

Frequency rate-of-change and voltage rate-of-change triggers are the most commonly applied triggers. Previous papers at this conference have suggested that real power rate-of-change triggers also have the sensitivity and selectivity to trigger recording for power system faults, without triggering recording for power equipment faults.[1] Impedance triggers are an interesting case for this paper. Impedance triggers will only operate when the center of impedance of a power system fault is close to the location of the DSR. However, there are some events, such as load encroachment, or when the DSR is located close to the center of impedance, where this trigger can capture valuable data.

Sampling rate. The minimum sampling rate required by NERC is 6Hz. However, a higher sampling rate, such as 30Hz or 60Hz, provides a more accurate picture of the measured electrical quantities during a power system event, providing frequency responses up to 15 and 30Hz respectively.

The requirements for disturbance recording as described in this section are a synthesis of the requirements as defined by a few of the Regional Coordinating Councils of NERC. For complete details of an individual RCC, please see [3], [4], [5].

The term Dynamic Swing Recorder is a generic term to describe any device capable of capturing RMS or phasor values of electrical quantities. While typically a DSR is simply a function available in a digital fault recorder, other devices may have the capability to capture this type of data. One such device is the Phasor Measurement Unit (PMU), a device that measures synchrophasors, a highly accurate time-synchronized phasor measurement. The typical PMU is designed to communicate these synchrophasors to system operators for real-time control of the power system. However, some PMUs have the ability to trigger on system anomalies, and record synchrophasor data, to meet the requirements of disturbance recording.

2.1 PMUs as Disturbance Recorders

An AC waveform can be mathematically represented by the equation:

$$x(t) = X_m \cos(\omega t + \theta) \qquad \text{(Eq. 1)}$$

where X_m = magnitude of the sinusoidal waveform,

ω = 2 * π * f where f is the instantaneous frequency

ϕ = Angular starting point for the waveform

Note that the synchrophasor is referenced to the cosine function. In a phasor notation, this waveform is typically represented as:

$$\overline{X} = X_m \angle \theta$$

Since in the synchrophasor definition, correlation with the equivalent RMS quantity is desired, a scale factor of $1/\sqrt{2}$ must be applied to the magnitude which results in the phasor representation as:

$$\overline{X} = \frac{X_m}{\sqrt{2}} \angle \theta$$

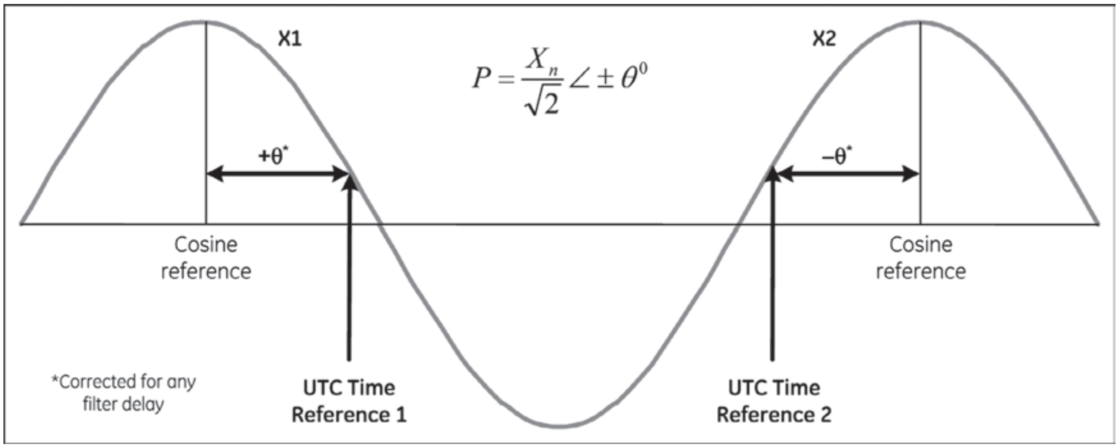

Figure 1.
Synchrophasor definition

System Frequency Reporting Rates:	50 Hz		60 Hz				
	10	25	10	12	15	20	30

Table 1.
Synchrophasor Reporting Rates

Adding in the UTC-based absolute time mark, a synchrophasor is defined as the magnitude and angle of a *fundamental frequency* waveform as referenced to a cosine signal (Figure 1).

In Figure 1, time strobes are shown as UTC Time Reference 1 and UTC Time Reference 2. At the instant that UTC Time Reference 1 occurs, there is an angle that is shown as "+θ" and, assuming a steady-state sinusoid (i.e. – constant frequency), there is a magnitude of the waveform of X1. Similarly, at UTC Time Reference 2, an angle, with respect to the cosine wave, of "-θ" is measured along with a magnitude or X2. The range of the measured angle is required to be reported in the range of $\pm \pi$. It should be emphasized that the synchrophasor standard focuses on steady-state signals, that is, a signal where the frequency of the waveform is constant over the period of measurement.

In the real world, the power system *seldom* operates at exactly the nominal frequency. As such, the calculation of the phase angle, q, needs to take into account the frequency of the system at the time of measurement. For example, if the nominal frequency of operating at 59.5Hz on a 60Hz system, the period of the waveform is 16.694ms instead of 16.666ms – a difference of 0.167%.

The captured phasors are to be time tagged based on the time of the UTC Time Reference. The Time Stamp is an 8-byte message consisting a 4 byte "Second Of Century – SOC", a 3-byte Fraction of Second and a 1-byte Time Quality indicator. The SOC time tag counts the number of seconds that have occurred since January 1, 1970 as an unsigned 32-bit Integer. With 32 bits, the SOC counter is good for 136 years or until the year 2106. With 3-bytes for the Fraction Of Second, one second can be broken down into 16, 777,216 counts or about 59.6 nsec/count. If such resolution is not required, the C37.118 standard allows for a user-definable base over which the count will wrap (e.g. – a base of 1,000,000 would tag a phasor to the nearest microsecond). Finally, the Time Quality byte contains information about the status and relative accuracy of the source clock as well as indication of pending leap seconds and the direction (plus or minus). Note that leap seconds (plus or minus) are not included in the 4-byte Second Of Century count.

2.2 Synchronized Phasor Reporting

The IEEE C37.118 revision of the IEEE 1344 Synchrophasor standard mandates several reporting rates and reporting intervals of synchrophasor reporting. Specifically, the proposed required reporting rates are shown in Table 1.

A given reporting rate must evenly divide a one second interval into the specified number of sub-intervals. This is illustrated in Figure 2 where the reporting rate is selected as 60 phasors per second (beyond the maximum required value, which is allowed by the standard). The first reporting interval is to be at the Top of Second that is noted as reporting interval "0" in the figure. The Fraction of Second for this reporting interval must be equal to zero. The next reporting interval in the figure, labeled T0, must be reported1/60 of a second after Top of Second – with the Fraction of Second reporting 279,620 counts on a base of 16,777,216.

2.3 PMU Distributed Architecture

The Synchrophasor standard and associated communication protocol was designed to aggregate data from multiple locations. As each dataset is transmitted synchronous to top

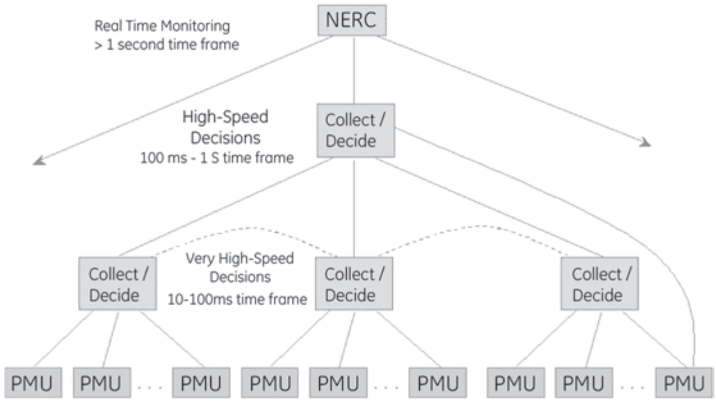

Figure 2.
Synchrophasor reporting hierarchy.

of second and as each transmitted dataset contains a precise absolute time stamp, the data aggregation function becomes a simple matter of combining sets of data with common time stamps. The "box" that performs this function is known as a Phasor Data Concentrator or PDC. In a "total" system, there will be a hierarchy of PDCs as shown in Figure 2. The hierarch is designed to support different performance criteria/data rates – depending on the application. With the assumption that higher-level PDCs operate at lower data rates, the data from the lower layer PDCs provides the most frequency resolution. Depending on type and number of PMUs installed in a substation, a substation-based PDC may or may not be required as this function can be integrated into the PMU.

A major advantage of Synchrophasor measurements compared to a normal DSR is that, as a result of standardization, data from multiple manufacturers can be seamlessly integrated. This is possible because the Synchrophasor standard requires that magnitude and phase angle errors resulting from magnetic and filter components be compensated in the final result.

Throughout North America, there exist today "pockets" of data concentration. Specifically, the Eastern Interconnect Phasor Project (now the North American SynchroPhasor Initiative – NASPI) has created a network of PMUs that span most of the eastern half of the continent. Data is being streamed at a rate of 30 phasors/sec into a Super Phasor Data Concentrator as operated by TVA. Communication bandwidths in the order of 64,000 to 128,000 bits per second will be required – depending on the number of data items and the selected stream rate. At the receiving site, real-time visualization of the data is available. Additionally, the data is archived and can be retrieved to perform system dynamic analysis as well as forensic analysis for larger system events.

In as much as remote communications may be disrupted by an event, most PMUs/PMU Systems have the ability to locally store synchrophasor data based on a range of event triggers. Typical triggers include over/under frequency, rate of change of frequency, over/under voltage, over current, over/under power, and status change. Synchrophasor recording times in excess of 20 minutes can be obtained within the confines of existing PMU memories.

3. Wide Area Recording

The benefits of disturbance recording, or power swing recording, are already well established. The phasor data captured in these records are used to validate system models of the power system, validate the operation of system integrity protection schemes and wide area protection schemes, and to provide root-cause analysis of equipment operation during power system faults. Some typical uses for the data include identifying the impact on the system due to a loss of generation or loss of a significant transmission line. Another use for this data is to analyze the performance of distance relays due to power swings. [6],[7] In all of these cases, for proper analysis, the phasor data must be measured simultaneously at various points on the power system. By collecting and coordinating records from multiple locations, the engineer can evaluate the response of the system, and specific equipment, to a power system or power equipment fault. The challenge is to capture simultaneous recordings across the system.

The present method of disturbance recording is to use discrete recording equipment, and local triggers. DSRs are placed at key locations on the system. Each DSR is configured much like a protective relay: trigger criteria are specific for the location of the DSR. Therefore, a DSR will only create a record when a power system fault is observable at the location of the DSR. Therefore, the more remote a DSR is from the center of inertia of an event, the less likely the DSR will capture a record for an event. Also, local triggers are dependent on the propagation time of the event across the system. A common trigger for DSRs is rate-of-change of frequency. In one known case, full load rejection of a 1,100MW generating station took approximately ½ second to propagate across the utility power system.[7] Local triggers will therefore be problematic in such a case. With discrete DSRs, and local triggers, records (such as for the load rejection example) may be created at different instances in time. An engineer must identify, retrieve, and combine the appropriate records from multiple devices. And this assumes that all the DSRs in use are accurately time-synchronized, typically to Coordinated Universal Time using GPS clocks.

Wide area recording or wide area cross-triggering can solve some of these issues. Wide area recording creates one synchronized record across the power system when any local DSR triggers a recording. The challenges in a wide area recording system are similar to that of local recording, with the added complexity of communications channel time delays. The only wide area recording system presently available is a closed, proprietary solution. This solution links DSRs as part of a client-server software system. When one DSR triggers a recording, this DSR sends a message to the server. The server then sends a message to trigger a recording, with the same trigger time, on all other connected DSRs. This system solves communications channel delay by using a rolling data buffer to store data in the DSR. Once the recording is finished, the server then retrieves the records from all the DSRs. This system absolutely requires that each DSR is accurately time synchronized, to ensure the data in the individual records are in phase.

Wide area cross-triggering sends a cross-trigger command to other DSRs via communications when one DSR triggers for a power system fault. Wide area cross-triggering has not been used, in part due to the challenges of communications, as the cross-trigger signal must be sent to multiple DSR locations simultaneously. Therefore, the complexity of communications is added to the same challenges in creating simultaneous records. However, the use of a PMU as the DSR can reduce these challenges.

In a typical DSR, although the records are time synchronized, there is no agreement among manufacturers as to how and when a measurement is made. However, when using a PMU as a DSR, the measurement is standardized and time synchronized per standard. Therefore, the trigger time of the record is not vitally important. The data from records captured at two different PMUs with different trigger times can be coordinated based only on absolute time.

The other challenge in wide area cross-triggering is sending the cross-trigger signal to multiple locations across the power system. This assumes an intact communication channel. Speed is not critical as long as the PMU can provide pre-trigger data memory. By setting the pre-event memory to be longer than the trigger and re-trigger communication time, no data is ever lost. The IEEE Synchrophasor standard has, as part of the message format, a trigger signal that is typically sent as a PMU-to-PDC signal. Once in the PDC, logic is needed to receive the trigger signal and then to forward it to all PMUs connected to the detecting PDC. Once the signal is received by one PMU in a station, that PMU can issue a GOOSE message to trigger other data captures or execute controls in other devices in the substation. Figure 3 illustrates this architecture.

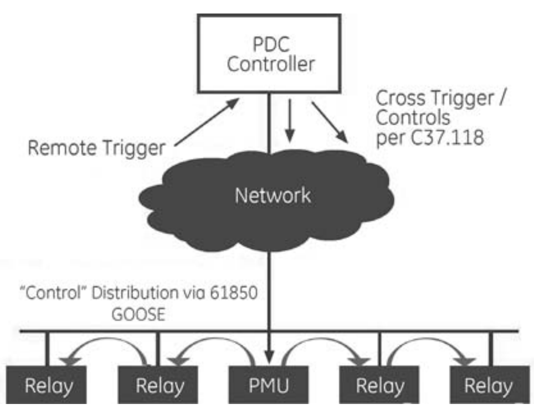

Figure 3.
Phasor Measurement Unit Cross-Triggering

3.1 The need for cross-triggering PMUs

PMU installations are normally designed to stream PMU data via communications to a centralized database that stores synchrophasor quantities for later analysis of the power system. This seems to eliminate the need for cross-triggering recording, as the data is readily available at a central location. However, the data is not necessarily available. As more devices, such as protective relays, can provide synchrophasors data, the less likely these devices will continuously stream data to the centralized database. The bandwidth of communications channels may limit data transmission, and data storage requirements may limit reception of data. Also, protection engineers may not have the same easy access to stored synchrophasors data as the system operations and system planning departments do.

In addition, for analysis of relatively local events, there may be the need to capture additional data beyond synchrophasors, such as power, power factor, and impedance. The cross-trigger signal can also be used to initiate recording in a traditional DSR as well.

4. Applications of PMU data for analysis

4.1 Large Motors

In the industrial environment, many processes have start-up and shut-down times that are in the multi-second time frame and sometimes, problems occur that either abort a startup or initiate an undesired shut-down. Traditional oscillography, although high-resolution, is typically set to record data only during fault conditions and, as such, will not record the longer start-up or shut-down events. Moreover, most industrials will own neither a swing recorder nor an oscillograph. Synchrophasor capability in motor protection can enable data capture in these instances and can provide a high-resolution, long-term view of these events. In addition, with proper trigger settings, the effects of power system disturbances on plant processes can be observed.

4.2. AGC / SIPS Analysis

System Integrity Protection Schemes (SIPS) is rapidly becoming a common occurrence in many utilities around the world. A SIPS event is usually a last ditch effort to prevent a complete power system shut down. It is very desirable to measure the effect of a SIPS action on the electric power grid. This measurement is most easily effected through the collection of synchrophasors across the system. Using the cross-triggering methodology previously described, the wide-ranging effects of a SIPS action can be observed and used to validate system studies and models.

One such scheme protects large multi-generator power plants against the severe disturbances that occur on transmission lines. Based on the disturbance severity, the typical results are intensive swings or loss of plant synchronism, which will lead into loss of the entire generation complex either by out-of-step protection, or unit shutdown by protective devices reacting to voltage dips at auxiliary buses. Wide area recording of synchrophasors allows the analysis of the power swing phenomena across the system, to verify the operation of the SIPS scheme.

4.3 Capacitor Bank Performance

Capacitor Banks are used to help maintain a flat voltage profile on the transmission system. Capacitor bank installation typically use some type of automatic control to switch in and switch out the capacitor bank. This switching operates on some criteria involving time of day, voltage magnitude, reactive power magnitude, or power factor. The performance of the capacitor bank is monitored at the system operations level by direct observation of the changes in the system voltage. Direct recording of the changes to local part of the system could provide some interesting insights into the impact of capacitor bank operation on the system voltage.

The primary data necessary to analyze the performance of a capacitor bank is the voltage magnitude and the reactive power flow. PMUs directly record the voltage and current synchrophasors and can also record the real power, reactive power, power factor, and system frequency. Consider the arrangement of Figure 4. Rich Substation is a major load substation, with a switched capacitor bank that operates on voltage magnitude. Recording PMUs are installed at both Rich Substation and Mark Substation, a major transmission substation. The PMU at Rich Substation is configured to trigger a recording on operation of the capacitor bank controller. Both PMUs are configured to send a cross-trigger command via IEC61850 GOOSE messaging.

A voltage profile may look something like that of Figure 5, where increasing load drags the system voltage down. The voltage recovers after the capacitor bank is switched in.

Recording the data at both PMUs can provide some valuable information. The basic information includes the voltage magnitude at each bus. Once the capacitor bank is switched in, the data will show the impact on the voltage at each bus, the amount of overshoot on the voltage correction, and the time lag between capacitor switching and voltage correction at the remote bus. The end goal of using this type of data is to improve the efficiency of capacitor bank switching, to ensure that bank switching procedures result in the desired improvement in system voltage level.

There are two advantages to using IEC61850 GOOSE messaging as the cross-trigger signal. The first advantage is the GOOSE message can be sent to one specific device or group of devices, or it can be sent to all devices on the system. In this example, GOOSE messages need only be sent between the two PMUs. The second advantage is the non-proprietary nature of IEC61850.

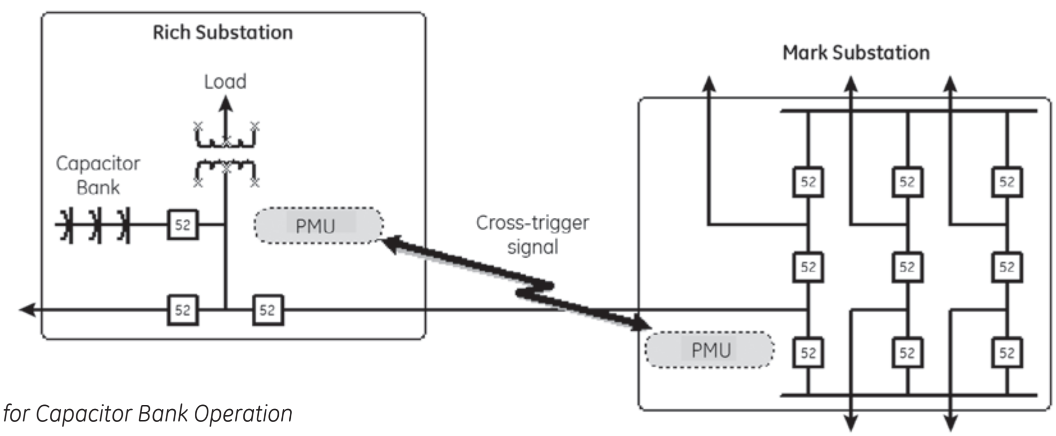

Figure 4.
PMU Cross-Trigger for Capacitor Bank Operation

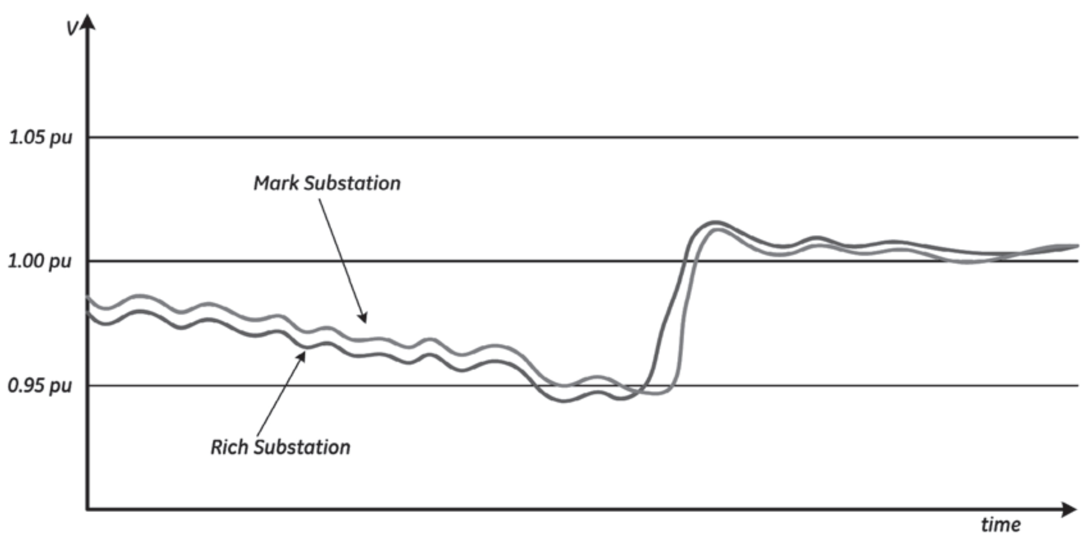

Figure 5.
Capacitor Bank Operation Voltage Profile

It is more typical that a PMU will not be installed at a simple load substation. However, any device that can send an IEC61850 GOOSE message, such as a modern capacitor bank relay, can send a cross-trigger signal to the PMU at a remote substation. This ensures a local switching operation still captures valuable data.

4.4. Analysis of Load Shedding Schemes

Underfrequency and undervoltage load shedding schemes are used to prevent system collapse. The typical scheme uses a local relay with a fixed threshold against voltage or current. A block of load is shed when the frequency or voltage drops below this threshold. Multiple thresholds are typically used to shed multiple blocks of load. The power system phenomenon that predicates the use of a load shedding scheme is a reduction in the system frequency or system voltage due to a significant imbalance between generation and load. At an individual device location, the apparent impedance will fluctuate in response to the changes in the system voltage and current.

Analysis of the performance of a load shedding scheme requires both verifying the performance of local devices, and verifying the performance system-wide. Recording synchrophasors in the substation, along with power flow and device data, can verify the local operation of the load shed devices, and the local impact on load. Capturing this data across the system can verify the performance of the load shed scheme system-wide. In addition, this information can be used to determined the center of inertia of the system during the event, and how close the system was to the voltage instability point.

4.5. Distance Relay Performance During Small Disturbances

Not all disturbances need to be a system-wide phenomenon to be of interest to study. Significant changes in voltage or current may cause the operation of a distance relay. Of special concern are distance relays that use a large over-reaching zone as remote backup of lines from the next station. Even small disturbances, such as the loss of a nearby generator, or heavy line loading, may cause the operation of this distance element. PMUs can be used to identify events where the apparent impedance of the line comes close to a tripping zone of the relay.

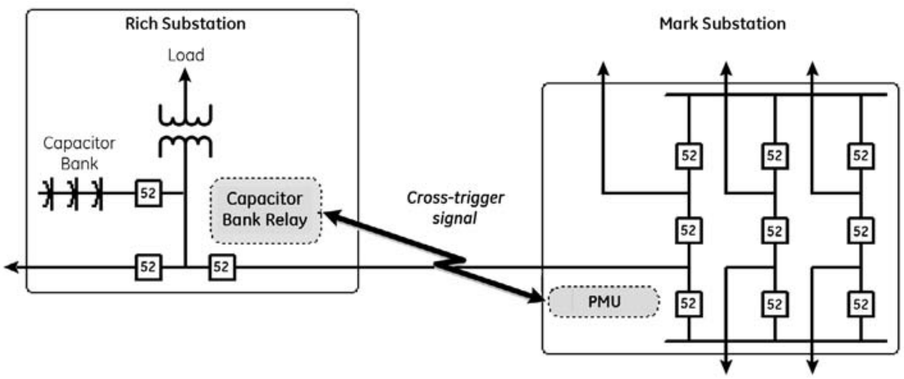

Figure 6.
Load Substation without PMU

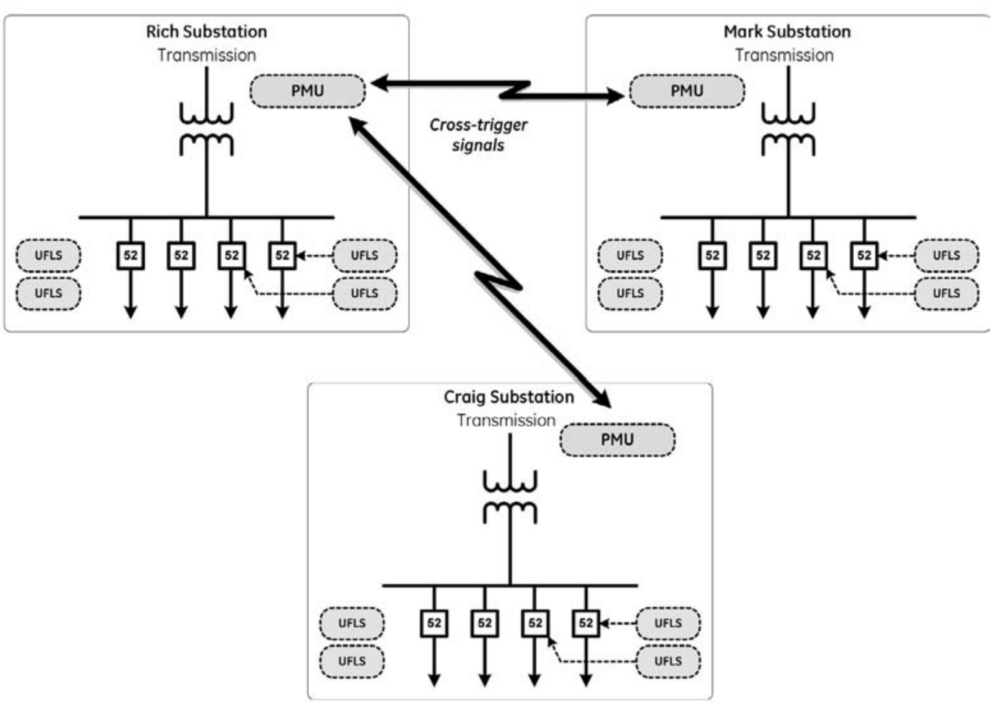

Figure 7.
Cross-Triggers for Load Shedding Analysis

Consider the simple transmission system of Figure 8. There is significant generation located one bus away from Mark Substation. When this generation trips off, a small power swing occurs. This power swing may encroach into the relay operating zone for the relay at Rich Substation.

The data that is most interesting is the apparent impedance as seen by the distance relays at both ends of the line. This requires the recording of the current and voltage by both PMUs. In terms of the total power system, this disturbance may not be significant and may not trigger criteria. However, the local PMUs can be configured to recognize the power swing conditions and capture a recording. The cross-trigger signal can be an IEC61850 GOOSE message that is only received by these two PMUs. A big advantage of PMU data, is the synchrophasors data is always synchronized.

Figure 9 shows some results for a small-scale disturbance. The apparent impedance seen by the relay came close to the largest tripping zone of the distance relay. This small margin justifies a contingency study to determine if the reach settings for this zone are secure against local small-scale system disturbances.

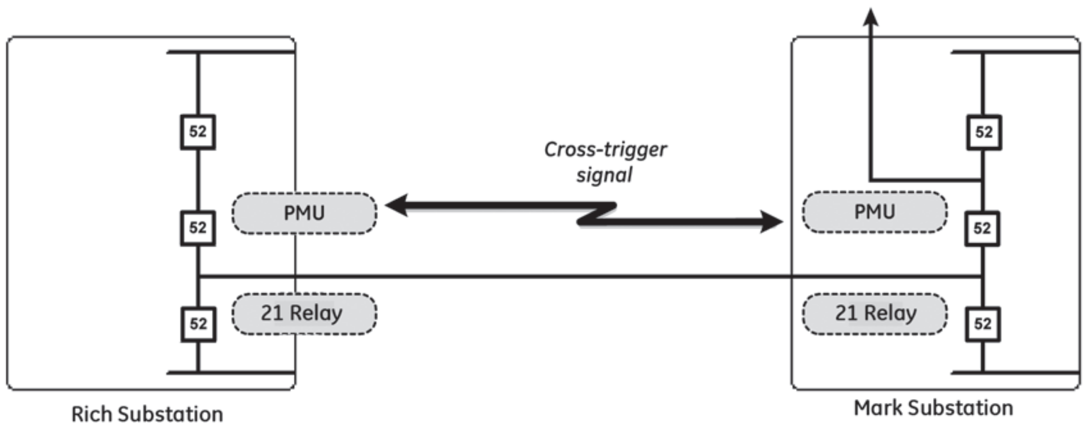

Figure 8.
Transmission Line Example

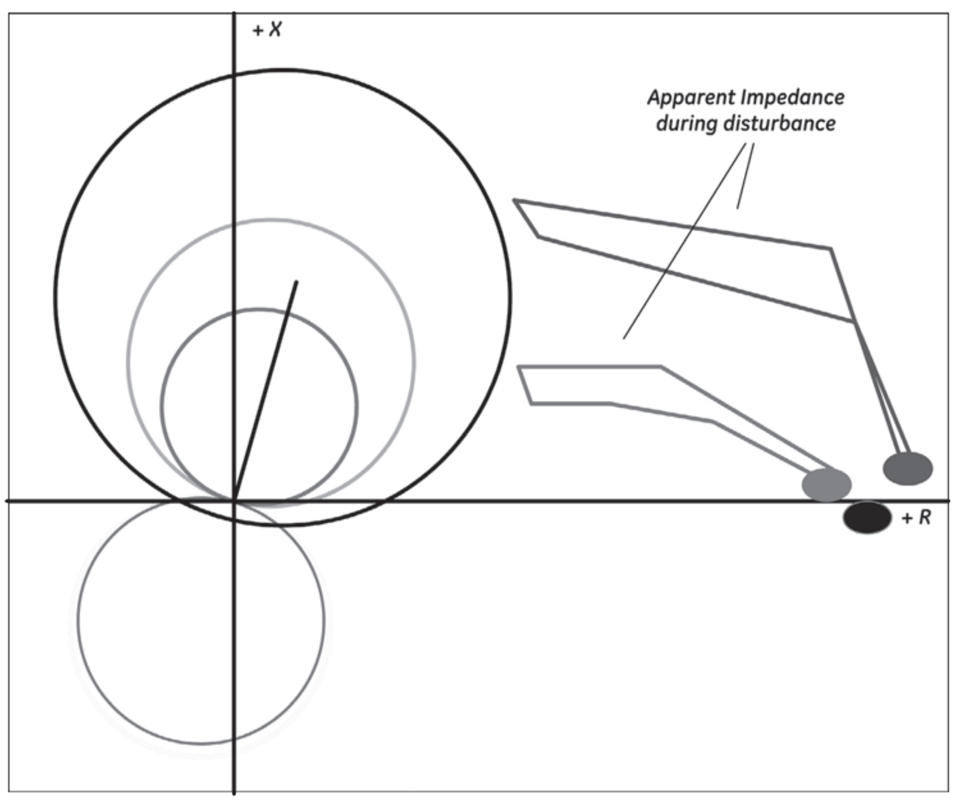

Figure 9.
Apparent Impedance During Disturbance

5. Conclusions

The value of disturbance recording to analyze the response of the power system to power system faults is well established. For this reason, the NERC guidelines for recording require utilities to capture RMS or phasor values of voltage, current, frequency, and power to analyze power system faults. Phasor measurements with recording capabilities are ideal devices to provide disturbance recording. The explicitly time-synchronized synchrophasors data meets the accuracy requirements and time requirements of the NERC guidelines.

The real strength of using PMUs for disturbance recording is the ability to easily support wide area recording using existing communications networks. Capturing data at various points on the system provides better analysis of system performance during power system faults. The challenges of synchronizing data are eliminated, as each piece of data is explicitly time synchronized. Cross-triggering signals are sent via non-proprietary communications, such as defined in the IEEE Synchrophasor standard and IEC 61850 standards.

6. References

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Status on the First IEC61850 Based Protection and Control, Multi-Vendor Project in the United States

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1. Abstract

The new IEC61850 substation communication standard is almost two years old. Worldwide, there are already over one hundred substations that have been commissioned and running with this new standard. Several projects in North America have been implemented with IEC61850 by using products from a single manufacturer. This paper will report on the status of a 500KV project, which is the first multi-vendor project in the United States to use this new standard. The goal of the project is to utilize the new IEC61850 standard to its fullest (as practically possible) therefore confirming that the standard is much more than just a communication protocol. Interoperability, one of the major advantages of IEC61850, will be demonstrated. The focus of the paper is not to describe or explain the theoretical background of the standard itself but rather to show and demonstrate the practical use of an actual multi-vendor project and how the standard applies to protection engineers. In addition, the paper will describe to the relay engineers that an IEC61850 based system must be considered an integral part of the protection and control system and not just another protocol integration for substation data/automation.

The paper will describe the process that was developed and used during this project to configure the IEDs, clients, and the communication infrastructure as defined by the customer. The exchange of IED configuration data between different vendors was achieved by using the IEC61850 defined Substation Configuration Language (SCL). We will demonstrate how each vendors private tools can export data into a standard format and be integrated into a common product using standard tools as well. The meaning and the purpose of the standard ICD files (IED Capability Description) and SCD files (Substation Configuration Description) will be explained.

One goal of this project is to eliminate or significantly reduce wiring between the relays and between the control house and the breakers. The wire reductions are replaced with the communication infrastructure fulfilling the protection and control applications by exchanging IEC61850 GOOSE messages over Ethernet (e.g. breaker position and protective trips).

The paper will also cover test tools and procedures that were used to find and eliminate problems during the integration of the protection & control system and the new IEC61850 standard. Lessons learned throughout the project will be discussed.

2. Introduction

Tennessee Valley Authority (TVA), a major transmission and generation utility in North America, designed a 500kV-to-161kV substation to integrate the IEC61850 communication standard across all protection & control IEDs within the substation, with the exception of one IED. This project brought together several manufacturers (Siemens, GE Multilin, ABB and AREVA) to accomplish this task. Protection, control and communication engineers from Siemens, GE Multilin, ABB and AREVA have worked on this project since late 2004/early 2005 and have been actively involved with the streamlined design using the IEC61850 standard. The project name is the *"Bradley 500kV Substation"* and its location (just outside Chattanooga, TN) is shown in Figure 1.

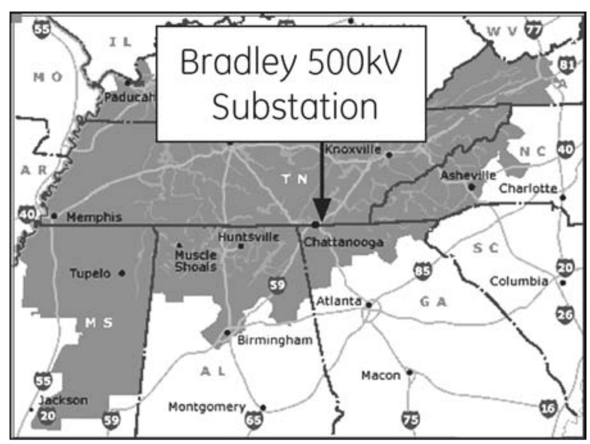

Figure 1.
Substation Location

The Tennessee Valley Authority, set up by the U.S. Congress in 1933, is a federal corporation and the nation's largest public power company with 33,000 megawatts of dependable generating capacity. TVA's power system consists of a diverse mix of fuel sources, including fossil, nuclear, hydro, and renewables. TVA has eleven coal fired plants, three nuclear plants, 29 hydroelectric plants, six combustion turbine plants, one pumped storage plant, 17 solar power sites, one wind-power site, and one methane gas site. Coal plants typically provide about 60 percent of TVA's power. TVA supplies power through a network of 17,000 miles of transmission line, 117,000 transmission structures, and 1,025 interchange and connection points. TVA sells power to 158 local distributors that serve 8.6 million people and 650,000 businesses and industries in the seven-state TVA service area. TVA also sells power to 61 large industrial customers and federal installations. TVA covers almost all of Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia.

An excellent group of TVA personnel made this Bradley project a success. Jim Kurtz, Manager of Protection & Control at Tennessee Valley Authority, had the following comments on the project:

"I am very proud of the effort by all concerned on the project. I believe the industry is about to see a transformation that will improve operation, maintenance, and reliability while at the same time reducing the cost for design, construction, and maintenance.

I cannot stress how important collaboration like this is to the industry. For our suppliers to work together to resolve issues will help not only the suppliers provide a better product but also a product that will meet the long term needs of the industry.

While this effort has leaped TVA forward in technology, we still have work to complete. The process bus needs to be proven and the tools to provide interoperability need to be much easier to use to accelerate the application of the standard."

In addition, Craig McClure, Senior Design Engineer at Tennessee Valley Authority, had the following comments on the project:

"Teamwork was the most important factor to achieve success on the project. Engineering barriers did not exist. The team provided a complete Protection and Control system. With just a bit more product and programming tool maturity, we will be able to do more for less and save significant money on the life cycle cost of a substation."

3. Substation Design & Layout

The Bradley substation incorporates the IEC61850 part 8-1 station bus standard utilizing Logical Nodes and the GOOSE messaging for all protection & control for 500kV & 161kV transmission lines and breakers, transformer "A" set protection, data acquisition of the transformer, transformer LTC control, breaker control, supervisory control & data acquisition (SCADA), operational interface panels (OIP), digital fault recorder interface and miscellaneous station data.

The IEC61850 IEDs used in the final design of the Bradley Substation are shown in Figure 2. Thirty-three (33) IEDs make up the IEC61850 implementation of this project.

- Line protection relays LA99A, LB99A, 9A99A, 9299A & 9B99A are GE-Multilin D60 relays (GE-D60).
- Line protection relays LA99B, LB99B, 9A99B, 9299B & 9B99B are ABB REL 670 relays (ABB-REL 670).
- Breaker control devices LA52BCA, LA52BCB, L252BCA, L252BCB, LB52BCA, LB52BCB, 9152BCA, 9152BCB, C1652BCA, C1652BCB, 9A52BCA, 9A52BCB, C2652BCA & C2652BCB are Siemens 7SJ64 relays (SIEMENS-7SJ64).
- Transformer protection relay 87A is GE-Multilin T60 relay (GE-T60).
- LTC control and transformer monitoring 30TA, 30TB, 30TC & 30TS are GE-Multilin C30 relays (GE-C30).
- 30SHA - Set "A" substation alarms and auxiliary control logic is GE-Multilin C30 relay (GE-C30).
- 30SHB - Set "B" substation alarms and auxiliary control logic & IEC61850 interface to set "B" transformer protection is ABB REC 670 relay (ABB-REC 670).

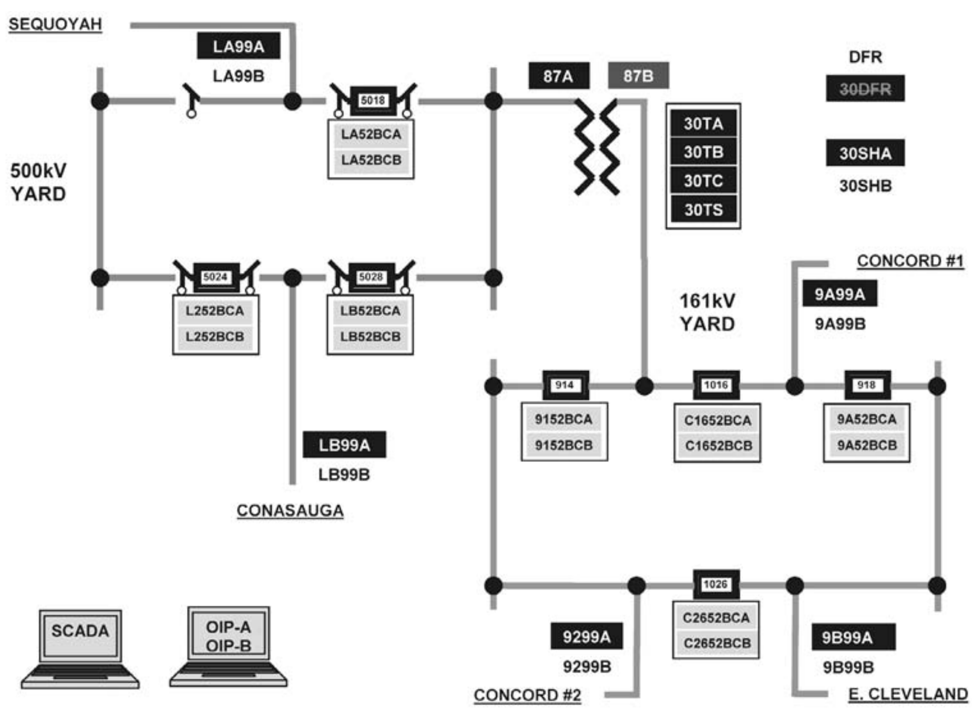

Figure 2.
Bradley Single Line (initial configuration)

- Digital fault recorder IEC61850 interface 74FRX is GE-Multilin C30 relay (GE-C30)

- SCADA gateway IED with both the station HMIs (OIP-A & OIP-B) graphical interface software are Siemens PAS system (SICAM PAS).

4. Protection & Control Scheme

Redundant protection, a TVA core protection requirement, is applied on all 500kV & 161kV transmission lines & breakers and three single-phase 500/161/13kV power transformers within substation.

4.1 Transformer Protection

Two complete, comprehensive and independent transformer protection packages/schemes are implemented. The transformer bank is a wye-wye-delta (500/161/13kV) with a 1200 MVA capacity through the use of four single-phase transformers (one is a spare). Set "A" protection (GE-T60) provides transformer differential protection, over current protection, transformer sudden pressure protection, hot spot protection, LTC sudden pressure protection and restricted ground fault (RGF) protection for both neutral CT's. Every transformer status and alarms, such as fan status, liquid levels, etc. are collected by the 30TA, 30TB, 30TC & 30TS devices (GE-C30), which are located in cabinets mounted on each of the four single-phase 500/161/13kV transformers. Analog and digital data from 30TA, 30TB, 30TC & 30TS IEDs are available in IEC61850 format to OIP-A, OIP-B and SCADA. All trip cut-out switches and lockout relays (LORs) for "A" set transformer protection are considered virtual and resident within the 87A IED logic. These virtual switches can be manipulated from OIP-A, OIP-B, SCADA or 87A front panel pushbuttons. LEDs and virtual LEDs on the OIP provide various system conditions relating to a complete transformer bank protection scheme. The 87B device is a non-IEC61850 IED using a conventional LOR (lock out relay) and hard-wire trips.

Typical transformer fault scenario

Condition: An internal fault to the transformer has occurred. What happens?

"A" set - The 87A IED determines a fault condition. Depending on the virtual 29DA trip cut-out switch (in the "ON" position), the 87A IED will issue a GOOSE message ("bank differential set "A" operated"). This GOOSE message will be used by each of the eight 52BC IEDs (SIEMENS-7SJ64) – LA52BCA, LA52BCB, LB52BCA, LB52BCB, 9152BCA, 9152BCB, C1652BCA, C1652BCB) to trip & lockout individual breakers & open corresponding isolating switches. The same GOOSE message will also initiate breaker failure protection within "A" set line/breaker IEDs (GE-D60) – LA99A, LB99A, 9299A, 9A99A. When a transformer fault condition is detected the 87A will also simultaneously close its output contacts (for risk management purposes), which are directly connected to trip the four breakers involved in the transformer differential zone of coverage.

"B" set - The 87B relay determines fault condition and closes its trip contact on the I/O board. This contact is in series with the 29DB trip cut-out switch (in the "ON" position) which energizes the 94B LOR. The 94B device has contacts wired directly to trip the four breakers involved in the transformer differential zone of coverage. The 94B also has a contact wired into the 30SHB device (ABB-REC 670) to indicate the transformer fault condition ("bank differential set "B" operated") to other IEC61850 IEDs, SCADA & local OIP-B. The 30SHB will then issue a GOOSE message to initiate breaker failure within "B" set line/breaker protection IEDs (ABB-REL 670) – LA99B, LB99B, 9299B, 9A99B for a transformer fault condition.

4.2 Line Protection

Line protection relays LA99A, LB99A, 9A99A, 9299A & 9B99A are GE-Multilin D60 relays and line protection relays LA99B, LB99B, 9A99B, 9299B & 9B99B are ABB-REL 670 relays (see Figure 3).

The ABB-REL 670 and the GE-D60 relays are used for all line protection requirements, which include distance/pilot protection, directional ground overcurrent, synchrocheck,

Figure 3.
"A" Set and "B" Set Protection

breaker failure and reclosing. The additional pilot teleprotection IEDs include the Pulsar UPLC (block/unblock) and the RFL Gard8000 (POTT). The Sequoyah 500kV line has individual POTT schemes for both line protection relays. The Conasauga 500kV line has the GE-D60 IED using an unblocking scheme and the ABB-REL 670 IED using a blocking scheme. On each of the 161kV lines, both line protection systems will share a single RFL Gard8000 for it's POTT scheme. Each line relay is operating in a breaker & ½ topology, such that two breakers are connected to each line relay with independent breaker currents and line & bus voltages wired.

Virtual selector switch logic for all line protection scheme and pilot enhancement packages (GE-D60 and ABB-REL 670 IEDs) has been implemented. The use of virtual selector switch logic within line relays streamlines the panel design and eliminates the need for external control switches. These virtual selector switches can be manipulated by the OIP, SCADA or IED pushbuttons/HMI. Each line relay is operating in a breaker & ½ topology and apparatus virtual switches are doubled providing a streamlined design.

Selector switch for group control – impedance relay

- Position 1 – Group protection setting 1
- Position 2 – Group protection setting 2
- Position 3 – Group protection setting 3
- Position 4 – Group protection setting 4

Selector switch for pilot scheme

- Position 1 – OFF
- Position 2 – ON
- Position 3 – TEST-SEND (test send a "permission to trip" or test send a "block trip" or test send "unblock trip" depending on scheme being used).
- Position 4 – TEST-SEND LRS (test send a low level signal of the same type commands listed under position 3 above. Even though all IEDs are equipped with this standard control scheme in it's logic, it is only used for the Conasauga 500kV line only).

Other front selection switches include:

- IED Remote/Local for OIP or SCADA control (From a relay logic perspective, this is the only virtual control switch that can not be controlled by SCADA).
- Transfer Trip Receiver (TT RCVR) to select different receiver options (OFF, ON, TEST)
- Transfer Trip Transmitter (TT XMTR) to select TT TEST-SEND or not.
- Breaker X Master Reclose (BKR X – RCLS MASTER IN/OUT) – enables/disables reclosing (IN, OUT).
- Breaker X Breaker Failure Trip-Cut-Out (BKR X FLR TCO IN/OUT) – disables breaker failure functions (IN, OUT)
- Breaker X Reclose Option (BKR X – RCLS OPTION) to select different reclose & synchrocheck options (3 position for a 500kV application and 7 position for a 161kV application)
- 161kV Breaker X Third Shot Reclose Option to select the third shot reclose options (IN/OUT).
- Breaker X Maintenance (BKR X – MAINTANANCE IN/OUT) – this feature sends "out of service" GOOSE message out to associated 52BC IEDs and block manual control of breaker via 52BC IED.
- LOR MASTER RESET is used in conjunction with GOOSE messaging from IED 30SHA or 30SHB which indicate the virtual LOR may be reset.
- Breaker Control
- Isolating MOD Control

Line relays exchange IEC61850 GOOSE messages for reclose cancel conditions and reclose enabled/disabled conditions.

Each line IED obtains status & alarm information from breaker control IEDs (SIEMENS-7JS64) within substation yard via IEC61850 GOOSE messages:

- Breaker position
- MOD ISO position
- Line ground switch position
- Breaker control position (CLOSE-NAC) – a virtual position from logic within 52BC device that aids in reclosing
- Low low gas – arm breaker failure (161kV breakers only) – used to by-pass the breaker failure timing circuit in 161kV applications.

For example:

- Line relay LB99A receives breaker 1 (5028) information from LB52BCA & LB52BCB and breaker 2 (5024) information from L252BCA & L252BCB.
- Line relay 9299B receives breaker 1 (914) information from 9152BCA & 9152BCB and breaker 2 (1026) information from C2652BCA & C2652BCB.

The line relays send the following IEC61850 GOOSE messages to associated 52BC IEDs (SIEMENS-7SJ64):

- Protective trip breaker
- Auto-reclose breaker

- Breaker failure trip & lockout
- Transfer trip & lockout
- Manual trip breaker
- Manual close breaker
- Manual trip motor operated disconnects (MOD)
- Manual close motor operated disconnects (MOD)

  Breaker out-of service (disable control of breaker via 52BC IED)

The only hardwire status input to each line relay is the breaker position statuses and this is only used if a digital IEC61850 state from either 52BCA or 52BCB devices are not available. A hardwire trip output from the line IED is wired directly to the breaker 1 and breaker 2 trip coils (for risk management purposes). With experience, future designs may provide the substation engineer the option to eliminate these hardwire inputs and outputs and to strictly use the GOOSE functionality.

Typical line fault scenario:

Condition: A line fault condition is present.
What happens?

Both the GE-D60 and ABB-REL 670 IEDs determine a fault is present. Both IEDs issue a GOOSE command for all associated 52BC IEDs (SIEMENS -7SJ64) to trip (trip both trip coils within a single breaker). Simultaneously, each line protective relay closes their own trip contact (for risk management purposes) that is parallel wired directly to the breaker trip coil [only TC1] serving that line. If auto-reclose is enabled, the GE-D60 will issue auto-reclose breaker GOOSE messages to the associated 52BC IEDs. If the GE-D60 is considered failed via it's power supply failure contact, the ABB-REL 670 relay will assume command and issue the same type GOOSE message. Also, each GE-D60 & ABB-REL 670 will initiate its own breaker failure scheme internally. That is, the GE-D60 initiates the breaker failure logic within its own box and likewise for the ABB-REL 670 (in some situations dictated by station topology, this breaker failure initiate command may be sent out as a GOOSE message to a corresponding device). If breaker failure is declared, then a breaker failure GOOSE message will be issued by line relay to associated 52BC IEDs to trip and lockout until a reset condition is given (reset when affected breakers are green flagged via manual trip operation of line relay) – see breaker control section for more details.

4.3 Transformer LTC Control

The substation transformers have a Load Tap Changer (LTC) for each of the four single-phase 500/161/13kV transformers (A, B, C, spare). Each LTC has controls enabling SCADA or OIP (via 30TA, 30TB, 30TC & 30TS IEDs) to raise or lower its tap position. These controls are in addition to the individual transformer LTC controls provided by the manufacturer.

With the transformers all being single phase units, each phase must have controls providing group and individual capability. This dual requirement is met by incorporating a five position selector switch (A, B, C, S & Group) logic in each 30TA, 30TB, 30TC & 30TS IEDs (GE-C30). The position of the virtual switch supervises the raise & lower commands sent to various LTC control units. That is, the OIP or SCADA will have the option to select which tap changer is to accept the raise/lower singular command submitted by the OIP-A, OIP-B and SCADA.

4.4 Breaker Control

Breaker control devices LA52BCA, LA52BCB, L252BCA, L252BCB, LB52BCA, LB52BCB, 9152BCA, 9152BCB, C1652BCA, C1652BCB, 9A52BCA, 9A52BCB, C2652BCA & C2652BCB are Siemens 7SJ64 relays (see Figure 4).

The substation contains redundant breaker control devices. The idea behind dual breaker control IEDs is to meet the same redundancy requirement as for line protection. The IEDs as shown in Figure 2 have generic names 52BCA and 52BCB. This defines a breaker (52) IED providing breaker control (BC) and which set (A or B) it corresponds. These devices are mounted inside an enclosure located on the breaker mechanism leg. This enclosure will be referred to as an IED auxiliary cabinet. The individual breaker's mechanism or control cabinet will be referred to as the main cabinet. Each breaker control 52BC IED will "listen" for a GOOSE message requesting their breaker or MOD to be operated.

Along with the breaker control IEDs, other components and devices will also be located in the IED auxiliary cabinet. They include a temperature thermostat, auxiliary cabinet heater, condensation monitor and an on-line breaker monitor.

Figure 4.
Breaker control IEDs

The breaker control IED (SIEMENS-7JS64) within the substation yard sends the following information to the line relays using IEC61850 GOOSE messaging:

- Breaker position
- MOD ISO position
- Line ground switch position
- Breaker control position (CLOSE-NAC) – a virtual position from logic within 52BC device to aid in reclosing
- Low low gas – arm breaker failure (161kV breakers only) – used to by-pass the breaker failure timing circuit in 161kV applications.

The breaker control IED (SIEMENS-7JS64) located in the IED auxiliary cabinet in the substation yard receives the following control messages from each line relay (GE-D60 and ABB-REL 670) located in the control house using IEC61850 GOOSE messaging and operates the associated output contact:

- Protective trip breaker
- Auto-reclose breaker
- Breaker failure trip & lockout
- Transfer trip & lockout
- Manual trip breaker
- Manual close breaker
- Manual trip motor operated disconnects (MOD)
- Manual close motor operated disconnects (MOD)
- Breaker out-of service (disable control of breaker via 52BC IED)

In addition to providing functionality that will monitor & operate high voltage circuit breakers and motor operated disconnect switches (MOD), each 52BCA and 52BCB IED performs several additional tasks. These include energizing/de-energizing the cabinet (main and auxiliary) heaters based on temperature or condensation, cycling of the heaters based on run-time, providing the breaker interlocking/blocking IEC61850 feature, virtual breaker control position, virtual breaker MOD control position and breaker alarm (logic within 52BC device based on hardwire inputs from breaker).

Each 52BC device builds it's own lockout bus based on all associated virtual LORs which prevents the breaker from being closed. The breaker may also be "blocked" from accepting manual commands should the "out of service" GOOSE message be received from either line relay.

If a transformer fault occurs, a latch is set within 87A and 30SHB (for 87B) that issue IEC61850 GOOSE messages to the 52BC IEDs of the four breakers involved in the transformer differential zone of coverage disabling the ability to close the breakers until reset GOOSE messages are sent by 30SHA and 30SHB IEDs. The reset bus logic resides within the 30SHA and 30SHB devices. For this particular fault condition, a reset will occur within 30SHA or 30SHB IEDs when the breaker (set "A" and "B") virtual breaker control position (logic within 52BC IEDs) has been set to TRIP/NAT (normal after trip) by manually tripping each of the line relays via front HMI or OIP that were associated with the event. The reset condition will be sent by IEC61850 messaging by 30SHA and 30SHB IEDs.

If a line relay breaker failure or transfer trip lockout has occurred, a non-volatile latch is set within line relay and IEC61850 GOOSE messages are sent to the associated 52BC IEDs disabling the ability to close the breaker until reset GOOSE messages are sent by 30SHA and 30SHB IEDs. Similar to a transformer fault, a reset will occur within 30SHA or 30SHB IEDs when the breaker (set "A" and "B") virtual breaker control position (logic within 52BC IEDs) has been set to TRIP/NAT (normal after trip) by manually tripping each of the line relays via front HMI or OIP that were associated with the event. The reset condition will be sent by IEC61850 messaging by 30SHA and 30SHB IEDs.

4.5 Substation Alarms & Auxiliary Control

Individual relay trouble alarms and breaker alarms are collected by the 30SHA (GE-C30) and 30SHB (ABB-REC 670) IEDs. As described above, the reset logic for a transformer fault, line relay breaker failure and line relay transfer trip resides within the 30SHA and 30SHB devices. A reset will occur within 30SHA or 30SHB IEDs when the breaker (set "A" and "B") virtual breaker control position (logic within 52BC IEDs) has been set to TRIP/NAT (normal after trip) by manually tripping each of the line relays via front HMI or OIP that were associated with the event. The 30SHA and 30SHB IEDs issue IEC61850 GOOSE messages to pertinent line and transformer relays. The reset condition will be sent by IEC61850 messaging by 30SHA and 30SHB IEDs.

4.6 Substation DFR Interface

Device 74DFRX (GE-C30) is the interface between the digital fault recorder (DFR) and specific IEC61850 status and trip conditions of the IEC61850 IEDs within the substation. Contact outputs of the 74DFRX are wired to inputs of the DFR. Future substation designs will eliminate the DFR.

5. Network Connections

All IEC61850 IEDs are connected via 100MBps multi-mode fiber cables to Ethernet switches located in the control house. VLANs are used within the IEC61850 GOOSE message configuration of each IEC61850 device to provide security within the network. Figure 5 shows a conceptual layout of the network and Figure 6 shows a detailed layout of the network.

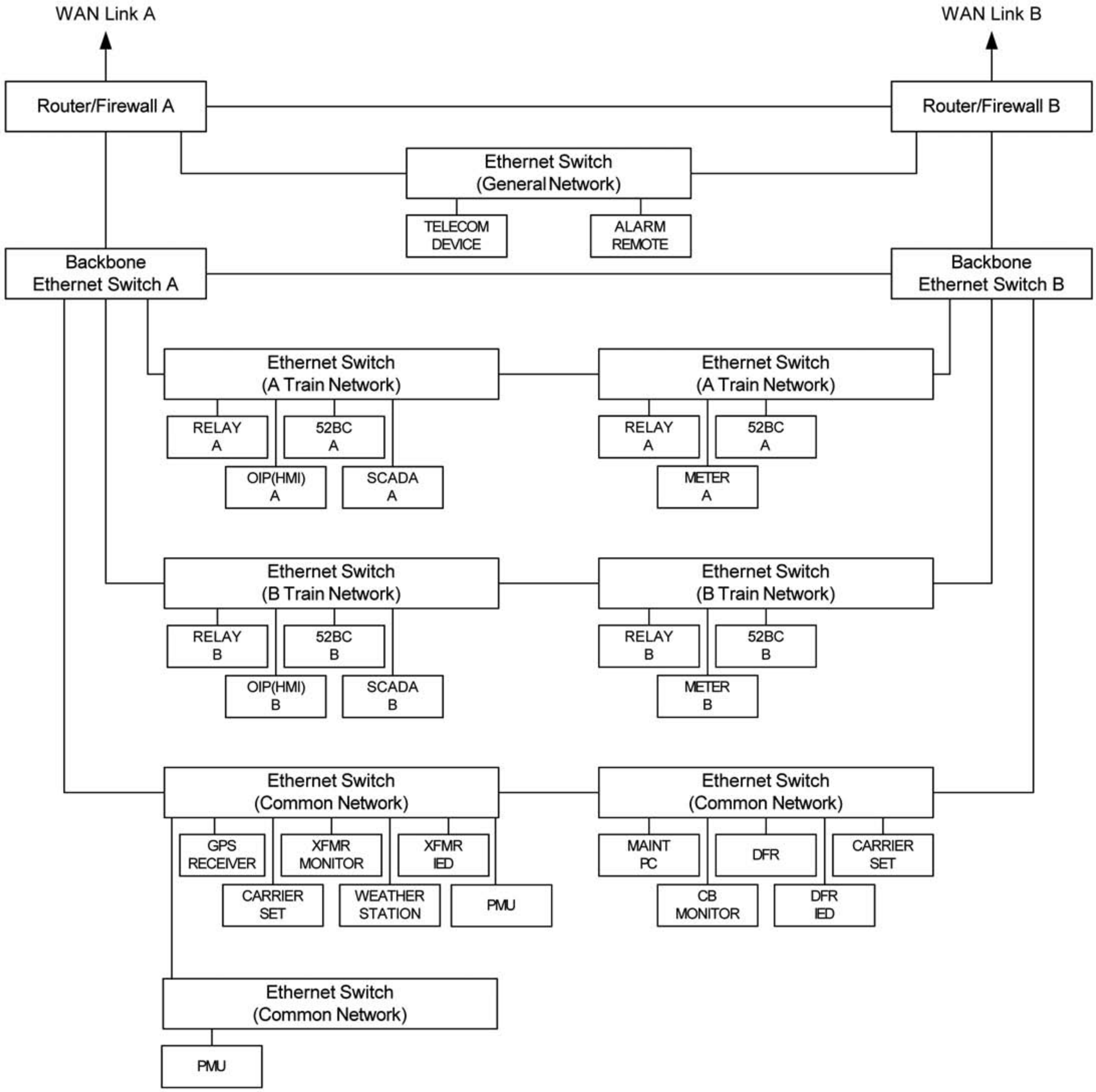

Figure 5.
Conceptual Network Layout

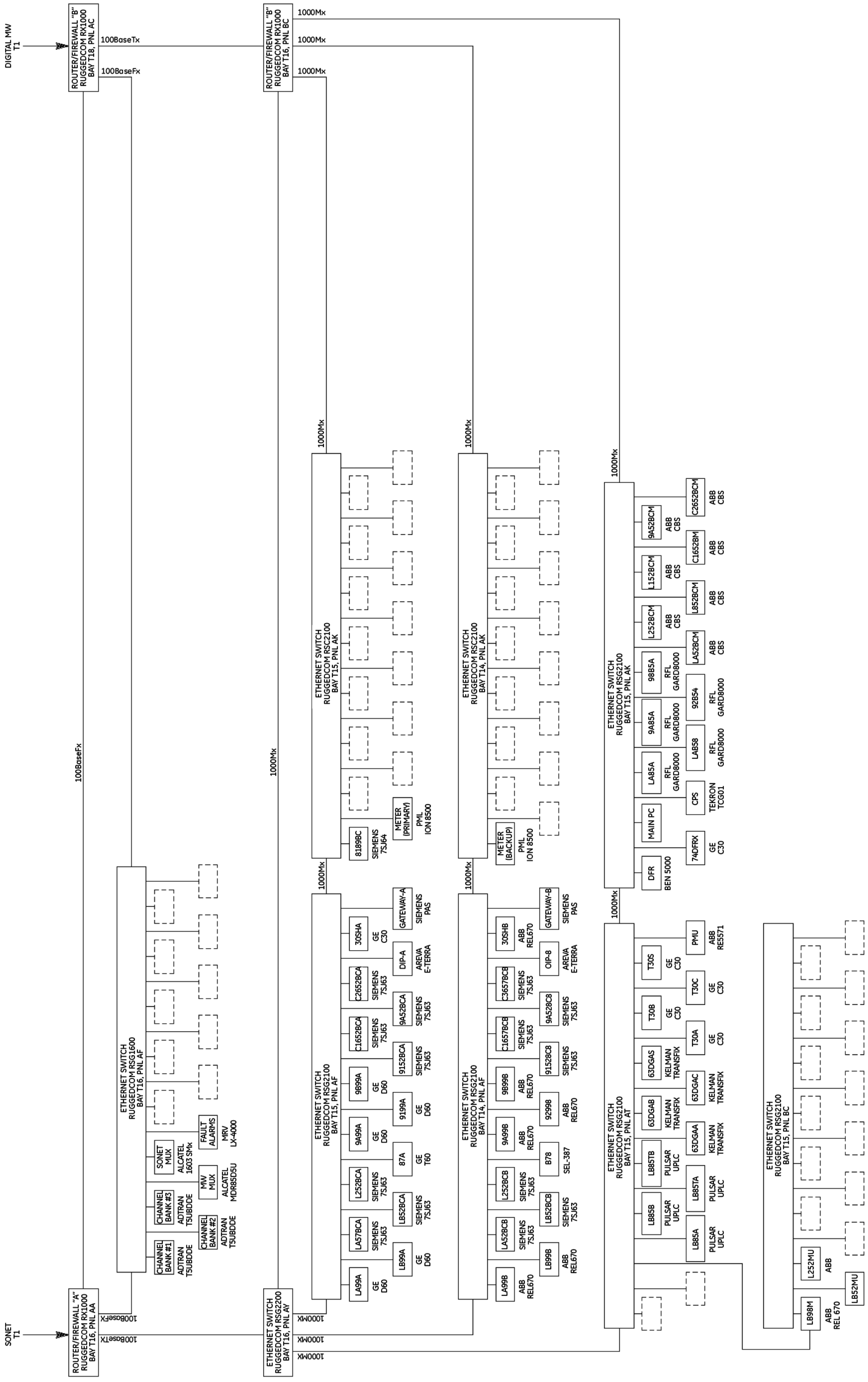

Figure 6.
Detailed network layout

6. Customer/Project Expectations

A goal of this multi-vendor project was to utilize the new IEC61850 standard to its fullest, as far as possible. Some of the key customer/project expectations were/are:

- *Open system for protection, control and data collection from any IED.*
- *Interoperability between IEDs for protection & control functions*. Ability to configure IEC61850 system with available manufacturer tools without need for on-site manufacturer support.
- *Comparable functionality with streamlined design*. Eliminate panel control switches and lockout relays and incorporate functionality into IEC61850 IEDs. This dramatically reduces the panel layout design and allows for a smaller control house (about ½ the size vs. traditional design). For example, consider just one set of protection, up to 12 breakers can be protected and controlled using one single 19" wide panel versus older designs with 1 breaker per panel with both Set A and Set B protection systems. Standard panel designs for any application can be created.
- *Accommodate multiple vendor IEDs*
- *Comparable performance time*
- *Secure & dependable overall system*. Timely, secure flexible information transfers.
- *Flexible management/operation*
- *Economically viable solution*
- *Common technology infrastructure*
- *Reusable practices*. Project established foundation of new substation practices oriented around IEC61850 and new procedures. Business case can be made for wholesale refurbishment with these new practices.
- *Effective data management system*
- *Reduced wiring, installation costs*. Besides the CT & PT wiring from switchyard breakers and motor operated disconnects, only breaker status and breaker trip wiring has been implemented. No inter-wiring exists between any of the IEC61850 IEDs.
- High-speed local and remote downloads to IEDs over network
- *Improved Operations & Maintenance from remote and local monitoring & diagnostics via network to reduce service time*
- *System health/status monitoring*
- *Status communications between IEDs*
- *Testing methodology* New test plan and methodology needed to match systems new capabilities and plan to implement test cases. Ability to individually test any IED without the concern of operating other IEDs via network.

7. On-site Lab Workout Sessions & Configuration Tools Used

In August 2005, the TVA IEC61850 "project team" met for the first time to begin the process of designing the first US - IEC61850 high voltage substation. The team consisted of four major relay vendors and TVA representatives from their relay and communication engineering departments. Besides all interoperability demonstrations organized previously by the UCA International Users Group or by CIGRE, the team's objective for this project was to show that each relay vendor demonstrate interoperability of the protection and automation devices from design to implementation in real life.

During the IEC61850 integration process, there were three primary tests at the TVA "test lab" substation which the four relay vendors participated. The tests were defined with the purpose of demonstrating that TVA could take the primary lead of configuring their substation with the available IEC61850 configuration tools using the manufacturers in a support role. This would be the first IEC61850 project where the customer would do the system engineering and IED integration and not the relay manufacturer. The integration during previous interoperability tests on other projects throughout the world had been implemented by members of the relay vendors development department using tools and programming language that were not always accessible or available for use by the customer. All participating vendors had previous experience with commissioning several IEC61850 based substation worldwide, but in almost all cases one of the vendors was the integrator and mainly used their own products, engineering tools and integration procedure to configure a substation. The integration of these previous projects was simpler because interpretation of the IEC61850 standard was uniquely confined to that vendor's system architecture and product implementation. It is also important to note that trade show interoperability testing only covers a small portion of the functionality required for a complete substation solution. So, the TVA project in this respect was completely different from previous projects and the trade show interoperability tests. TVA was the system designer and system integrator and they would use the available and released IED tools from each vendor and they would rely on unique interpretations of the new IEC61850 standard by each vendor.

7.1 Configuration Tools, ICD and SCD Files

During the first test meeting (August 2005) the "project team" met, the primary goal was to configure all GOOSE links between the relays from the different manufacturers and to reach a minimal level of device interoperability. The procedure to achieve this is shown in Figure 7. All manufacturers had to supply an ICD file (IED Capability Description) that described the ability of the relays in a standard IEC61850 format. This ICD file is the interface between the relay manufacturers IEC61850 tools and the IEC61850 world. With the ICD files available, the customer can use any independent IEC61850 System Configuration tool to import the ICD files from each relay vendor and configure the system. Once the IEC61850 station is configured, a SCD file (Substation Configuration Description) can be exported describing the station in a standard format defined in IEC61850.

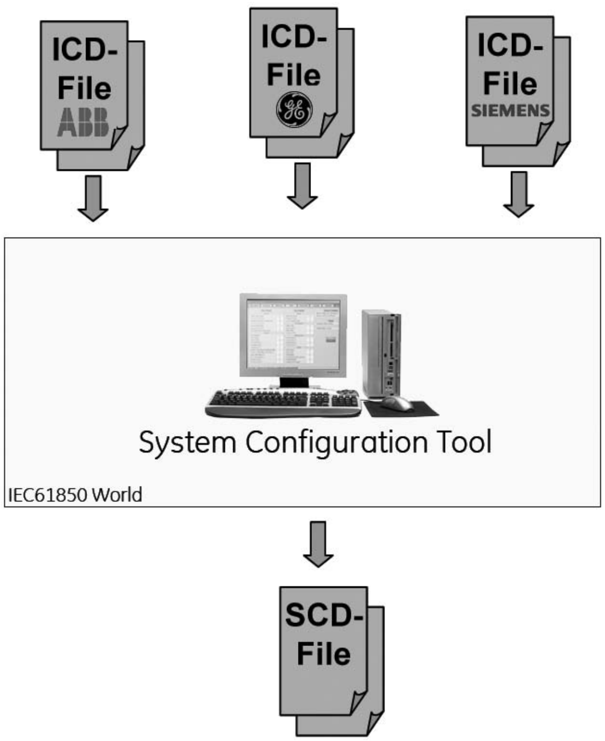

Figure 7.
IEC61850 File Standards

The relay vendors must be able to use their proprietary tools to extract the information inside the SCD file which is needed to configure the individual relays of the different relay manufactures. TVA decided to use the DIGSI software from Siemens as the System Configuration tool. When the design process began on the TVA project, the Siemens – DIGSI tool was the only commercially available IEC61850 station configuration tool with all the required functionality.

7.2 Lessons Learned & Testing Tools Used

During the first test meeting (August 2005), there was a significant amount of discussion on the details of how the team wanted to achieve their goal. One discussion was centered around what type of GOOSE message should be used. The question of whether TVA wanted to use the GOOSE message implemented in UCA – called GSSE which is defined in IEC61850 to provide compatibility with UCA 2.0 implemented substations, or did they want to use the real IEC61850 GOOSE message – called GOOSE. After evaluation of all pros and cons, the decision was made to use the IEC61850 GOOSE message because of the advantages this new implementation has to offer.

There were also discussions that made it apparent that all relay vendors did not fully understand the power of the new standard. For example, it was thought that it was necessary to manually configure which information in a GOOSE message was to be sent first, the data information or the quality information. It was discovered that different manufacturers and sometimes, different relays from the same manufacturer did it differently, so there was a fear that the information may get misinterpreted. After a lot of discussions and phone calls, the team determined that the order of the information and quality data did not matter as long as it declared in the ICD file. The receiving relay will get the information because it is defined via the SCD file and it knows how to process the information correctly.

During this first test meeting (August 2005), most relay vendors did not have their tools ready to automatically export and import from their proprietary programming tools to the IEC61850 world via ICD and SCD files. This resulted in a significant amount of manual programming work. To validate the correctness of the ICD file, the team used the DIGSI System Configurator as well as the IEC61850 Validator tool. It was determined initially that some of the ICD files had some format errors and during the import of the files, an IEC61850 Validator tool produced error reports as shown below (see Figure 8). These errors were the first hurdle that had to be resolved.

Even though the validation of the ICD files could verify the correct syntax of the file, it could not check for the semantics. Once we were able to import the ICD files and use the System Configurator tool to configure the required system, in some cases, we were not able to receive the programmed GOOSE message because the GOOSE message description was different than what was actually described in the ICD file. To analyze problems where one relay vendor claimed that they

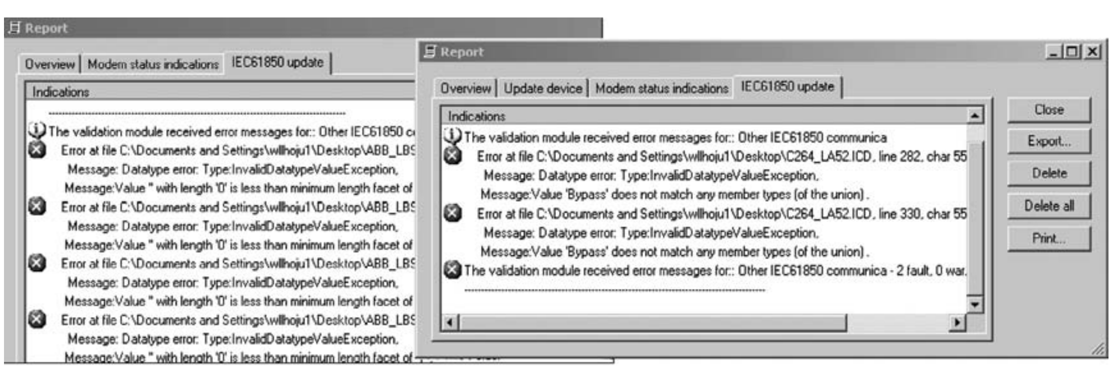

Figure 8.
IEC61850 Validator Tool

were sending a GOOSE message and the receiving vendor did not receive, the team used the network protocol analyzer tool Ethereal® with the MMS decoder functionality. Ethereal® allowed for the entire GOOSE structure to be displayed, so that a view of the specific relay IED including the value of the data and quality information could be analyzed (see Figure 9).

By using Ethereal®, we were able to see where adjustments were necessary and finally all GOOSE messages were sent and received correctly between IEDs of the different relay manufacturers. The goal for the test week was achieved and the concept of IEC61850 was proven powerful. Even with this accomplished, configuration of the TVA system was not simple. However, the tools available would allow the customer to configure the system by themselves. During the design process, there were several firmware updates, patches and discussions between the development departments of each of the relay manufacturers. Without the great teamwork between all the manufacturers and the deep knowledge of the implementation details of IEC61850, the interoperability goal could not have been achieved. Initially, it was clear that this was not a practical procedure that a utility could use to configure their IEC61850 substations.

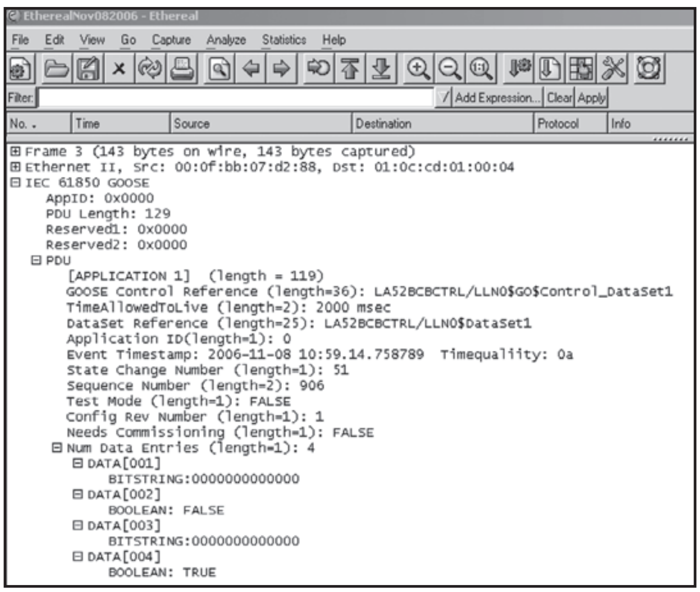

Figure 9.
IEC61850 GOOSE message using Ethereal®
(Ethereal is a registered trademark of Ethereal, Inc.)

The second test week was conducted in January 2006. The goal was to have TVA configure the system with as little as possible support from the relay manufacturers. The goal of TVA was to be the system designer and integrator. We have to admit that this goal was not achieved, because again some of the manufacturers tools were still not mature enough to allow the customer goal of system integration responsibility. A lot of manual work was still required and a special IEC61850 knowledge was also necessary in order for the correct ICD files to be generated and extracted out of the SCD file for configuring each IED. With support of the relay manufacturers, the system was successfully working and configured at the end of the week, but the actual goal was not achieved. At the end of the second test meeting, TVA requested that each relay vendor finish their tools so that they can have the capability of configuring an IEC61850 system independent of the relay manufacturers. A third test week was scheduled for March 2006.

In the third test week (March 2006), all manufacturers met again in the TVA "test lab" substation. Focus was now on the tools of the manufacturers and if they were able to support TVA in configuring their IEC61850 substation without any major support from the relay vendors and a need to have deep knowledge about the IEC61850 implementation details. The tools from ABB, GE Multilin and Siemens were found mature enough to fulfill the customer requirements. However, a new problem was discovered regarding different tools supporting different optional features of the IEC61850 standard. For example, the ABB IEDs need to know some hierarchical data like "voltage level", "feeder name" in each IED. This data can be submitted to the IEC61850 system configurator via the SSD files (System Specification Description). This file format is optional in IEC61850 and doesn't have to be implemented. The DIGSI system configurator in this case did not support this feature at this time. This made it necessary that after the SCD file was created by the DIGSI system configurator that the file was edited by an ABB tool to add this hierarchical data and then re-imported in the DIGSI system configurator.

At the end, TVA was able to develop a procedure that allowed them to configure and design the system independently without on-site support from the different relay manufacturers. This was demonstrated by TVA during the preparation for the May 2006 IEEE T&D show in Dallas, TX where the Bradley project configuration proved interoperability in the UCA International Users Group IEC61850 demonstration. TVA built the demonstration panels and configured the system that was placed on display at the show using the IEC61850 tools provided by each vendor.

Overall, the process involved a number of hurdles, but demonstrated that by having a strong and determined team of relay manufacturers and excellent group of TVA engineers, future IEC61850 project implementation can be successful and economical advantageous.

8. Client/Server Interface

The first several on-site lab sessions between the different vendors were used mainly for getting the relays configured, IEC61850 tools working properly and testing GOOSE communication. Next, came the point in time to check the relays integration to the clients (AREVA and Siemens). Client-Server interfaces have been tested between three graphical user interfaces (clients from two different suppliers) and different relays (servers from four different suppliers). See Figure 5 and 6 for network connections of IEDs and HMIs.

The client-server services that have been tested include connection establishment, data model retrieval, reports, measurements and control. The following are some observations & lessons learned during communication tests and client/server configuration.

- Data model retrieval: This communication service enables a client to discover a server's communication capabilities. It can be compared to a traditional web access where initially an electronic address is first entered and lead to the site discovery. This service has been proved to be extremely useful to simplify the client configuration.

- Buffered and unbuffered reports: This communication service is used to retrieve binary and analog data. Events (binary) are retrieved when there is a change of value or a change in the quality status. This was applied to GGIO (Generic I/O data) and XCBR (Circuit Breaker data) logical nodes. Analog data is sent periodically or when their change exceeds a dead-band limit. This service is subdivided into unbuffered and buffered reports. The benefit of buffered reports is to avoid the loss of data in case of a communication failure - the principle is to store the data normally sent into the server and send this archive once the communication is resumed. Whether to use buffered or unbuffered reports was a point of discussion between the different vendors for the communication from the IEDs (servers) to the substation control system (client). Unbuffered reports were tested with all devices. One relay vendor supported just buffered reports and another relay vendor can do both buffered and unbuffered reports. The relay vendor with the buffered report enabled his application to convert the reports to unbuffered.

- Report ID name: The Report ID needs to be unique inside each device. The Report ID assigned from one vendor had the same name for all devices and all the reports could not be imported into the client. The vendor created different reports for the client, but all of them had the same Report ID, thus the first report could only be imported into the client. The relay vendor made the necessary changes to the Report ID naming and all individual reports were successfully retrieved by the client.

- Length of the GOOSE ID: One vendor had the limitation for the length of the GOOSE ID. This vendor was not able to accept GOOSE ID's with more than 15 characters, thus the length of the GOOSE ID had to be limited within the project.

- Controls: Control was tested using the Select Before Operate (SBO) service to control the circuit breaker (XCBR).

- Controls without feedback: The SPCSO (Single Point Controllable Status Objects) are not contained in any Dataset. Datasets are the DataObject lists which are sent in the reports. Manual configuration of missed points (feedback of controls) for each relay vendor was necessary to allow the client to accept the controls.

- Measurements: We encountered the problem that the reports for measured values are built from data attributes. For example, an issue was encountered such that single phase values (DataAttributes) were individual items in an IED and the client wanted grouped three phase values (DataObjects). The client could not compute such reports. The reason for this is that expected datasets for client / server reports are built from DataObjects only. The reason behind this is that the value, quality and time from a unit that should not be split. Dividing up the information could lead to reports where only the value "mag" (magnitude) is reported, but not the quality and not the timestamp. Technically, there is also another problem with this report. According to IEC61850-7-3 the timestamp does not have a trigger option. Therefore, this value will never be reported (except in General Interrogation and integrity reports). Creating datasets from DataAttributes is acceptable for GOOSE communication where the entire dataset is always transmitted. For example, PhsAB is not a DataObject. However, PPV is a DataObject. In real world applications the other voltages, PhsBC and PhsCA, can also change their complex values. In GOOSE, all information is transmitted; it does not matter whether they are Data-Objects or Data-Attributes.

- Trigger options: The pictures below show the parameter for the trigger options associated to each report coming to the client from two different vendor IEDs/servers. While almost all vendors are using the Data Change, Quality Change, Data Update and General Interrogation options (see Figure 10), one vendor just sets the General Interrogation (see Figure 11). With only this parameter, the communication between the client and the relay will allow just a data transmission requested as General Interrogation. Using SISCO's AXS4MMS, an external tool as recommended by the vendor, it was possible to change the settings in the relay. Manually the setting has to be enabled to trigger option Data Change in SICAM PAS to match the relay (see Figure 12).

Part 6 of the IEC61850 standard defines the configuration process and the associated XML syntax known as SCL (Substation Configuration Language). The mechanism is to first get generic ICD (IED Configuration Description) files for each IED, then generate an SCD (Substation Configuration Description) file containing the definition of the dataset effectively used in the project, then import this SCD into each IED to synchronize the configuration of the different servers. While the standard places a lot of emphasis on the server side (i.e. relay), there is no restriction on the way the clients (i.e. OIP, SCADA) should be configured.

The client configuration mechanism was to dynamically "learn" the IED's capability at the connection establishment, i.e. logical node and datasets available. The benefit was to avoid the import of the SCD files, thus eliminate the coupling of the client configuration with the availability of this file (subject to a specific job, coordination of the various IEDs, interpretation, etc) and to accelerate the tests. This approach is certainly optimal for interoperability testing and should be complemented by some additional mechanisms in a real project. In this situation, all the IEDs might not be present during the database preparation and the overall database versioning must be handled carefully.

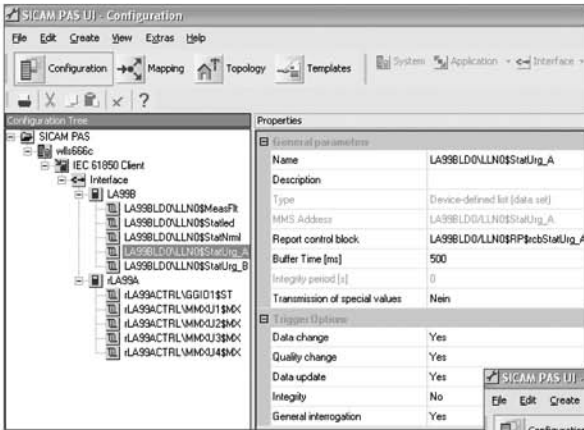

Figure 10.
Trigger Options

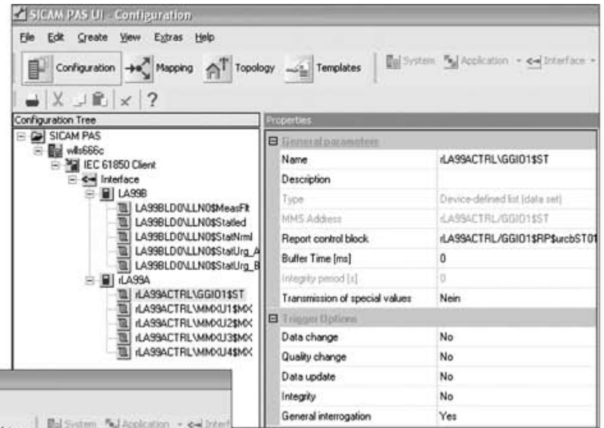

Figure 11.
Trigger Options

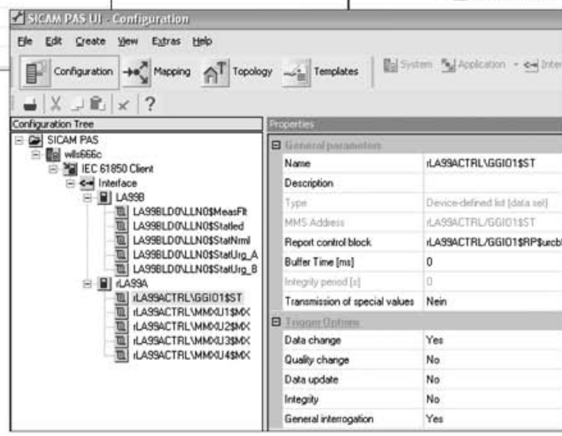

Figure 12.
Trigger Options

The experience in this project has represented a big challenge not just for the customer but also for each one of the vendors participating. With the engagement of the customer, it has also been possible to get the vendors working as one team where everyone has given the best to achieve the project goals. An aspect that needs improvement is that until now, the work has focused 95% on the GOOSE configuration and communication forgetting the client/server implementation & expectations. We should not forget that in GOOSE, all information is transmitted, it does not matter whether they are Data-Objects or Data-Attributes but in a client-server relationship, the server sends only a small subset inside an information report for which a trigger condition is sent to the client. These trigger conditions like Quality change or Data change refer to DataObjects, which contain attributes like quality or magnitude. At the time of submission of this article, the last test for the integration of the ABB, GE and Siemens IEDs with the SCADA Gateway (Siemens SICAM PAS) has been successful. That means the final integration has been achieved and the interoperability is functional.

9. Lessons Learned Throughout Project

This project was a tremendous learning experience for the participating vendors and TVA. In addition to those described in the on-site lab workout and client/server interface sections, the following are some of the additional lessons learned throughout the project.

VLAN issue with Ethernet switch - The Virtual LAN (VLAN), an advanced layer 2 function defined in IEEE 802.1Q, high priority tagging of a message provides an efficient means for data exchange in applications using GOOSE on IEC61850-8-1 station bus and IEC61850-9-2 process bus profiles. In the IEC61850 standard, a VLAN tag was defined as part of a valid GOOSE message. Some vendor's IED implementation required the VLAN tag in a received GOOSE messages to validate the information. The Ethernet switches used in the Bradley project initially did not pass the VLAN priority tag through the switch. This issue was identified early in the project and a firmware update was provided for the Ethernet switches.

Logical device names - Logical Device (LD) naming syntax is defined in IEC61850 part 7-2. The logical device names in this system were to be named according to the customer's standard practice for devices associated with breakers. The "99A" and "99B" breaker identification labels were preferred since this was TVA's standard for naming multifunction microprocessor based relays. The naming syntax restrictions defined in the IEC61850 standard does not allow these type of LD names (those starting with a number) due to constraints in MMS (Manufacturing Message Specification). The solution for this issue was to name the breaker IEDs (Logical Device names) "LA99A" and "LA99B" respectively.

GOOSE ID naming - GOOSE ID naming is an attribute that is contained in the GOOSE message. One IED vendor uses this GOOSE attribute to display status of received GOOSE messages. In the Bradley project's system engineering tool, the GOOSE ID was automatically assigned as a number although the standard is not restrictive to numbers and allows strings. The issue on utilization of IEC61850 data is that one vendor usage or extension of the data may not be possible with another vendor's implementation. The GOOSE ID strings in the SCD file were renamed using a separate tool capable of manually modification of GOOSE ID names.

Status vs. quality order - It was thought that it was necessary to specify which information in a GOOSE message was to be sent first, the data information or the quality information. It was discovered that different manufacturers and sometimes different relays from the same manufacturer did it differently, so there was a fear that the information may get misinterpreted. After a lot of discussions and phone calls, the team determined that the order of the information and quality data did not matter as long as it is declared in the ICD file. The receiving relay will get the information because it is defined via the SCD file and it knows how to process the information correctly.

The effect of the quality state has on the status state - Traditional/conventional hard wiring states are either on or off without an indication of signal quality. The IEC61850 standard does not provide rules for the interaction between quality and status bits. The question posed is should the loss of the quality state effect the state of the status value, thus a quality state of 0 results in a force of status state of 0 (even if the status is actually true or 1)? Or should a quality state of 0 result in staying at the last known status state (which is 1 in this example)?

Both vendors meet standard, but do not interoperate - Device (IED) conformance to the standard is accomplished by validating an IED at an accredited IEC61850 test facility in accordance to the IEC61850 part 10 and the UCA test procedures. It is important to note that the conformance testing does not validate conformity but only validates the IED testing has identified no "non-conformities". An IEC61850 device certificate is then issued by the accredited test facility providing the vendor a statement that no non-conformities were identified during the IED testing. The testing is limited to a single device in a test system and does not cover multi-device system level testing or interoperability in a multi-vendor system. To the point, the IEC61850 certificate does not guarantee that a certified device will interoperate with another device. Device level interoperability has been left to the vendors to validate device and client interoperability. In the Bradley project, all vendors had IEC61850 certified IEDs, but several issues as previously mentioned resulted from wrong interpretation or ambiguity in the IEC61850 standard. Other issues were also identified from wrong vendor implementations of the standard that were not identified during the certification process. Below are some examples of issues encountered during the Bradley project that impacted GOOSE interoperability between different vendor devices:

- **Supporting optional attributes in GOOSE** - One example of the interoperability issues encountered was that one vendor could include both mandatory and optional attributes in the IED using GOOSE messaging. Then in another vendor's IED (GOOSE receiver), this IED could only understand mandatory attributes and was not able to support the optional attributes; thus preventing interoperability. The resolution was to not use the vendor specific attributes in the GOOSE communication between these IEDs.

- **Adherence to name case sensitivity** - Another issue encountered was in the adherence lower and upper case sensitivity. One vendor was more liberal and did not strictly adhere to the case sensitivity as defined in the standard. The other vendor's engineering tool was rejecting the names when the case was opposite to that as defined in the IEC61850 part 7. This was resolved by using a newer version of the SCL XML schema.

- **Quality in GOOSE versus no quality** - The support of data item quality flags in GOOSE datasets was a major obstacle in the beginning of the Bradley project. Different vendors provided different levels of support for quality flag data. In this case, one vendor required quality information in their application to confirm validity of the data for each value received via GOOSE. At the same time, another vendor was not able to send quality information in the GOOSE message. This resulted in the inability to exchange GOOSE message between IEDs and thus, a major interoperability issue. It was decided to use both status and quality within the Bradley project for consistency. Both quality and status are now available in each vendor's device and successful GOOSE interoperability between multiple vendors has been accomplished.

- **Length of names of GOOSE Control Blocks** - The length of GOOSE control block names supported in the different vendor IEDs was an issue. The Bradley project's system engineering tool automatically generates names for DataSets and GOOSE Control Blocks. The string length of these automatically generated names were too long for one vendor's IED. The GOOSE Control blocks in the SCD file were renamed using a separate tool capable of manually modifying the GOOSE control block names.

- **Substation section** - The substation section of SCL file contains information about the substation layout, logical node references and device configuration and association information. One vendor's IED tool required this substation section along with the Logical Node references to be imported from SCD file generated by the system engineering tool. The system engineering tool was not able to produce the needed information so manual manipulation of the SCD files was required to complete the IED engineering. The resolution was manual configuration of the SCD file adding the necessary information.

What vendors have to improve to make it easier? - Better preparation of the product and system technology is needed. IEC61850 is a very comprehensive and complex standard that has the potential to revolutionize substation automation systems if the necessary tools and product functionality is available. The vendors involved in this project needed to collaborate to assure that the substation automation system functionality and interoperability capabilities were validated prior to the execution of the customer engineering and system build up.

Some limitations in vendor implementations made some necessary design choices at the beginning of the project. The concept of using only GGIOs for all GOOSE communication was the right approach to start some testing, but for the real system a solution using correct Logical Nodes should be considered.

For example, circuit breaker position using GGIOs are sent as separate Boolean signals for open and closed breaker commands. In the standard, there are Logical Nodes and Data Objects defined for this purpose.

Another area that has not been explored prior to this project is the engineering process. It is very important for the necessary information exchange between system engineering and IED tools to really take advantage of the many benefits developed in the IEC61850 standard.

What could have been done differently? - Clearly, the lessons learned in the multi-vendor TVA Bradley IEC61850 substation project have been extremely valuable for the entire industry pushing for this new standard. From the industry side, the availability of an IEC61850 certified device only validates an IED to a small portion of the standard and does not address complete device level interoperability. The extent of the Bradley project provides complete functionality with a goal to move into the digital substation.

We can state that the Bradley project has explored all benefits made possible through the new standard that prior to this project has not been done in a multi-vendor environment. Most of executed IEC61850 projects have been turnkey homogenous vendor solutions where interoperability between one vendor's products is much easier. In the other projects where multi-vendor projects have been executed, the foreign device has typically been a main 2 or backup protection terminal where the system functionality only required limited exposure of the IED functionality via the IEC61850 system.

On the other hand, industry expositions demonstrating multi-vendor IEC61850 interoperability have set expectations that the complete IEC61850 benefits are readily available. This is not the case since these demonstrations focus on simplistic applications and minimal functionality to prove vendor A can interoperate with vendor B.

What could have been done in this project is to set up an interoperability project to validate product and system functionality before starting the Bradley project. In this case, the project was conducting the interoperability validation. System engineering is the critical step in the Bradley project where an open discussion regarding system engineering tool to know the limitation in the integration of other vendor's IEDs. The system engineering process is one area that multi-vendor exchange of IED and engineering data needs improvements. Today, a vendor's system engineering tool works perfectly with their own devices but creates limitation when exposed to other vendor's devices.

What needs to be done in the industry is a higher level of interoperability functionality and standard test cases that can assure a minimum level of interoperability. Today, the actual substation automation system projects are performing this function but at a significant expense when untested IEDs are used for this first time in a system. The result is unnecessary project delays and cost increases. Here the recommendation is that the UCA International Users Group on behalf of the utilities set up performance and functionality criteria for levels of interoperability. Device level conformance certification only validates a fraction of the overall substation automation capability.

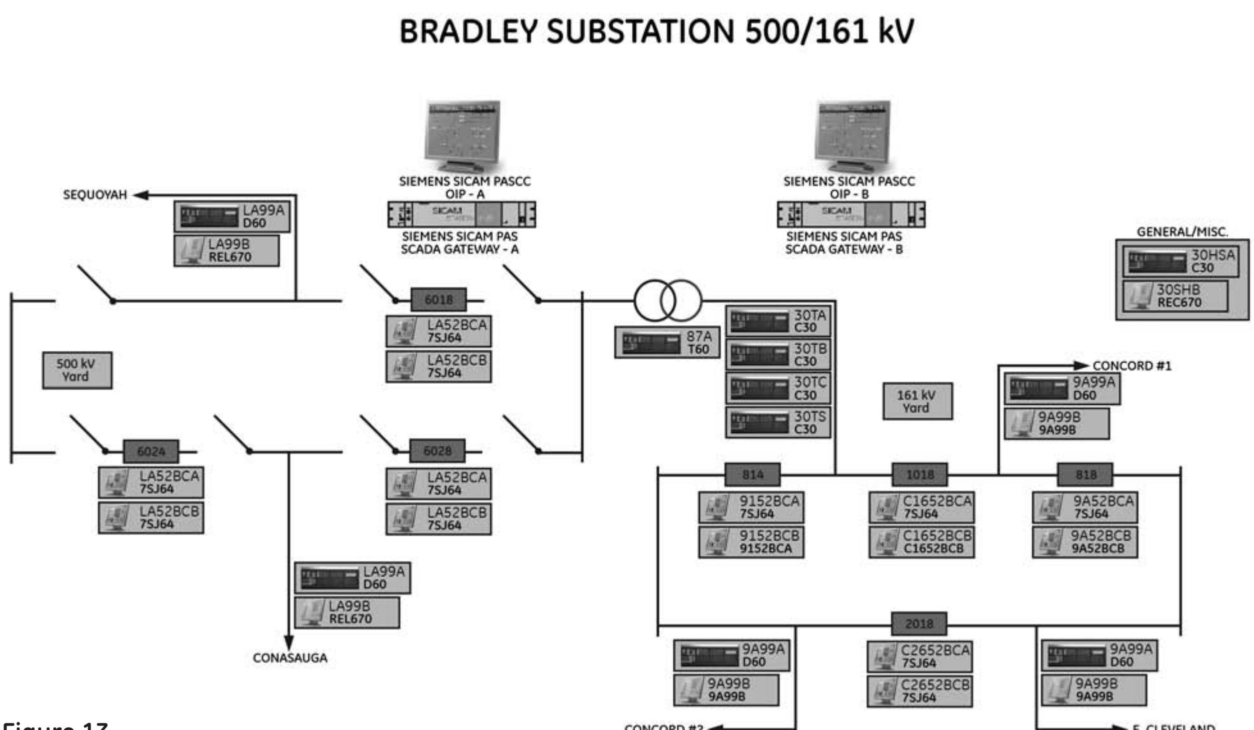

Figure 13.
Final configuration of TVA Bradley substation

10. Conclusions

A strong and determined team of relay manufacturers and an excellent group of TVA engineers made this Bradley project a success in utilizing the IEC61850 standard as much as practically possible. Figure 13 shows the final design being deployed for the TVA Bradley Substation.

The experience in this project created a big challenge not just for the customer but also for each one of the vendors participating. With the engagement of the customer, it has also been possible to get the vendors working as a collective team where everyone has given their best effort to achieve the project goals. It is in the best interest to the industry to evolve the technology based on IEC61850 since the standard has been developed through a vendor-utility collaborative effort.

The lessons learned in the device interoperability and IEC61850 engineering processes from the IEDs and software tools used by the vendors and TVA were very valuable. Successful IEC61850 GOOSE interoperability has been implemented between different relay manufacturers on this project. In addition, successful integration of the ABB, GE and Siemens IEDs with the SCADA Gateway (Siemens SICAM PAS) has been implemented. These lessons learned have resulted in the vendor's maturity in IEC61850 technology allowing future IEC61850 project implementations to be configured by the customer easily and without on-site vendor support.

Integrated protection, control and monitoring projects, such as the Bradley Substation, need to focus on all areas including client/server interface, not just the GOOSE configuration and communication.

The industry needs to develop a higher level of interoperable functionality and standard test cases that can assure a minimum level of interoperability. The UCA International Users Group on behalf of the utilities needs to set up performance and functionality criteria defining various levels of interoperability. Device level conformance certification only validates a fraction of the overall substation automation capability.

The industry should consider Ethernet Switches as a "protective device" when it comes to implementations of critical protection schemes using IEC61850 standard and whether they are configured and maintained by protection/test engineers or the IT department.

To look back in time, the vision established in the mid-1990s by the EPRI and AEP LAN Initiative is now realizable. Projects like the TVA Bradley 500kV project is truly the first US based multi-vendor IEC61850 substation automation system. This project has set the industry benchmark on complexity and functionality achieved through the utilization of products based on the new IEC61850 standard. This project's experiences will be valuable to many other utilities as they also proceed to adopt the new products and systems creating the next generation of digital substations.

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Windfarm System Protection Using Peer-to-Peer Communications

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GE Energy

Dale Finney
GE Multilin

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1. Introduction

Windfarm electrical systems present some unique challenges for protection. The grid tie and wind turbine generators provide multiple sources of fault currents to be considered. Collector feeders become isolated ungrounded systems during faults due to separation from the centralized collector bus reference ground. Ground faults on feeders will result in unfaulted phase voltages rising to line levels. In addition, severe transient overvoltages can be produced, which can degrade insulation resulting in eventual equipment failure.

This paper reviews the overall requirements for comprehensive windfarm protection. It also focuses on the particular problem of feeder ground faults. A novel, yet simple solution is presented that makes use of peer-to-peer (GOOSE) messaging via the IEC61850 protocol. The characteristics of the GOOSE message are discussed with respect to speed and reliability and communications architecture is presented. The performance of the resulting protection scheme is quantified.

2. Wind-Turbine Protection Considerations

The type of wind turbine unit will have some bearing on the protection requirements. There are several Wind Turbine Generator (WTG) configurations in commercial operation today. This discussion focuses on the doubly fed induction generator (DFIG). Figure 1 shows a single line diagram of a typical WTG and the location of the IED.

In this configuration a variable-pitch wind turbine is connected through a gearbox to a wound rotor induction machine. Back-to-back voltage-sourced converters are used to connect the rotor circuit to the machine terminals in order to provide variable speed control. The WTG step-up transformer has three windings. The high voltage winding is delta connected. Both LV windings have grounded-wye connections. One LV winding is connected to the stator circuit, the other to the rotor circuit. The high voltage winding of the transformer may be connected to the grid through a circuit breaker or through fuses.

Stator ground faults on the LV side of the WTG transformer are not detectable by upstream protections due to the transformer connection. The IED provides protection for these faults using an instantaneous overcurrent element. This element may respond to zero sequence, residual current, or transformer neutral current. The element requires no coordination with other protection elements, allowing it to operate with minimal time delay. If the element is measuring zero sequence via the phase currents or the residual current connection, then possible CT saturation during external faults should be considered when determining the pickup setting.

The IED also provides protection for LV phase faults. An instantaneous element will interrupt severe faults with minimal delay. Note that the DFIG will provide a contribution to external faults. This element should be set lower than the minimum current expected for a phase fault at the generator terminals and above the maximum expected generator contribution to a fault on the network. A time overcurrent element will detect phase faults internal to the generator. Upstream time overcurrent protections should coordinate with this element.

An IED with similar protection elements can also be applied to the converter circuit. This IED can detect faults up to the converter terminals but cannot detect faults in the rotor winding.

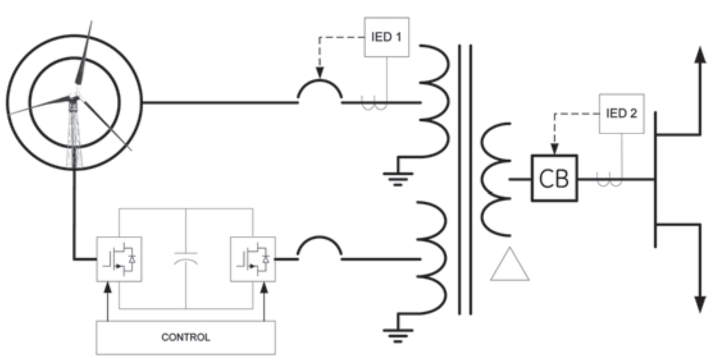

Figure 1.
WRG Single Line

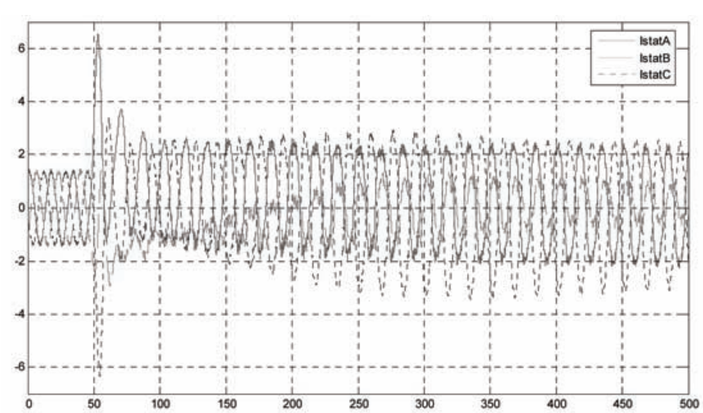

Figure 2.
Simulation of WTG contribution (pu) to an external ground fault

Auxiliary protective functions are also required for the DFIG. These protections may be embedded into the WTG controller or alternatively may be implemented within the IED. These include:

- Voltage unbalance
- Overheating (RTDs)
- Reverse phasing
- Poor synchronizing
- Voltage and frequency out of limits

The WTG also must be capable of isolating itself from a fault on the feeder. Ideally, this should be done with minimal delay. At the same time external fault protection should never operate for faults on adjacent feeders or on adjacent WTGs. Practically, it is not possible to achieve this level of performance solely through measurement of local currents and voltages. Typically, grid fault detection relies on undervoltage and overvoltage elements. These elements are delayed to allow upstream protection to open the feeder breaker, thereby preventing a trip for fault on another feeder.

Finally, the WTG IED should have the abilities to capture voltage and current waveforms and sequence-of-events data during a fault or disturbance. These are valuable tools for fault analysis and verification of protection system performance.

3. Windfarm Substation Protection Considerations

Figure 2 shows the single-line diagram of a typical wind farm. Several feeders terminate at the collector bus. A power transformer steps up the voltage to the transmission level. A single HV transmission line connects the windfarm to the grid.

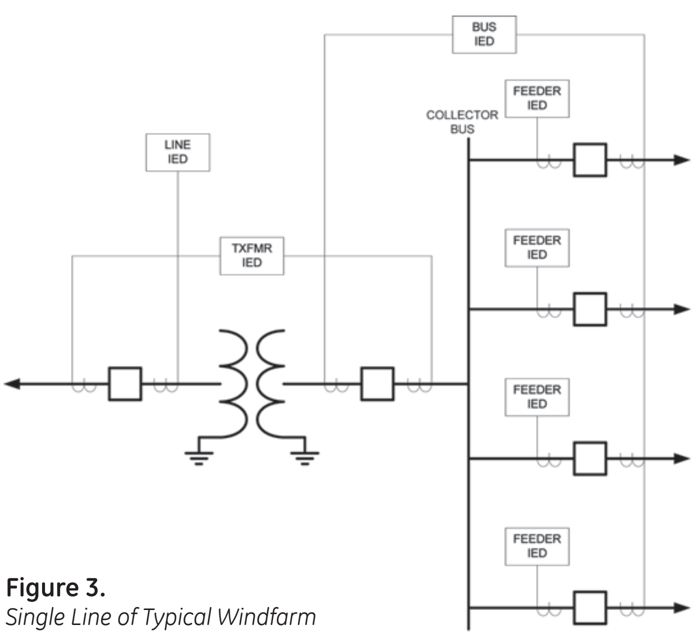

Figure 3.
Single Line of Typical Windfarm

Protection is required for the collector bus. A high or low impedance differential element will produce the fastest clearing times for bus faults. If a low impedance bus differential scheme is used, then the feeder CT should not be paralleled. Otherwise the WTG fault contribution can produce a false operation if CT saturation occurs during an external fault.

A blocking scheme can be applied as an alternative to the bus differential. An overcurrent element in each of the feeder IEDs sends a blocking signal to an overcurrent element located in an IED on the transformer breaker on the occurrence of a downstream fault. When a bus fault occurs, no blocking signals are sent. GOOSE messaging, discussed in detail below, over the substation LAN provides a convenient method of exchanging the blocking signals.

Protection is also required for the power transformer. This will take the form of a percent differential element with inrush inhibit. If the number of feeders is low then the bus and transformer zones may be combined using a multi-restraint transformer differential element. This allows the transformer breaker and CTs to be eliminated.

The windfarm may be interconnected to the grid via a two terminal transmission line or it may be tapped onto a multi-terminal line. In either case the protection of the transmission line typically takes the form of line differential or distance elements. Each scheme will require a dedicated communication channel linking the windfarm to the remote utility terminal(s) to provide optimum protection. A communications channel can also be used to signal to the utility terminal that the windfarm has been disconnected and that reclosure is permissible. Out-of-phase reclosing onto the windfarm will produce severe torque transients and must be avoided.

Reclosing for ground faults can be implemented in the case that single-pole tripping is employed. In this scheme the windfarm remains synchronized with the grid through the healthy phases. This will increase the availability of the windfarm but requires protective IEDs and circuit breakers that are capable of single-pole operation.

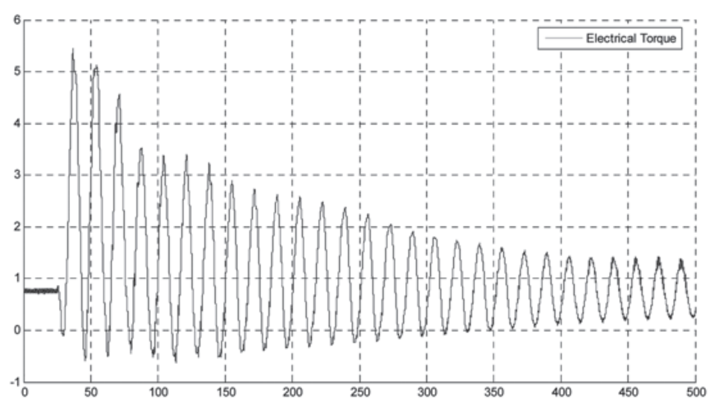

Figure 4.
Simulation of WTG Torque due to Reclosing Out-of-Phase

4. Windfarm Feeder Topologies

There are several types of feeder topologies currently applied in windfarms. Radial, bifurcated radial, feeder-subfeeder, and looped topologies are the most common types used, each yielding their own distinct advantages and disadvantages. These factors and other criteria such as wind profiles, available tower placement, costs, etc. must be considered in order when determining which topology to use.

Radial collector system topologies are comprised of a single feeder circuit originating from the collector bus and connecting sequentially to each WTG tower. It provides the least complex feeder configuration and is best suited in applications where linear WTG placements are well defined. It has a lower installed cost per feeder due to the low complexity. Inter-tower cable faults or WTG faults can be isolated to allow continued production. However, a station circuit breaker failure or a cable fault between the station and first tower result in complete loss of all feeder generation, which makes it one of the least reliable.

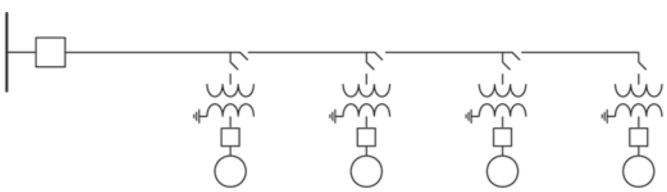

Figure 5.
Radial Feeder

Bifurcated radial topologies are similar to the radial system except they use one collector bus circuit breaker to switch two collector feeders. This configuration has the lowest installed cost base per feeder. However, it also has the lowest reliability because a breaker failure or a cable fault between the station and first tower result in complete loss of both feeders' generation.

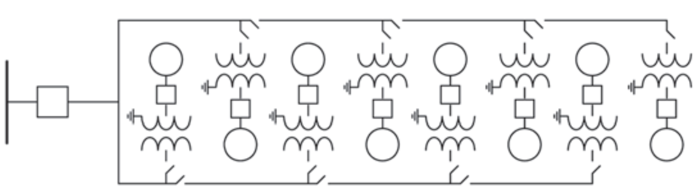

Figure 6.
Bifurcated Radial Feeder

Feeder-subfeeder topologies are typically employed where clusters of towers are distributed over large areas. They are typically comprised of a single cable feeding remotely located switchgear with several subfeeders.

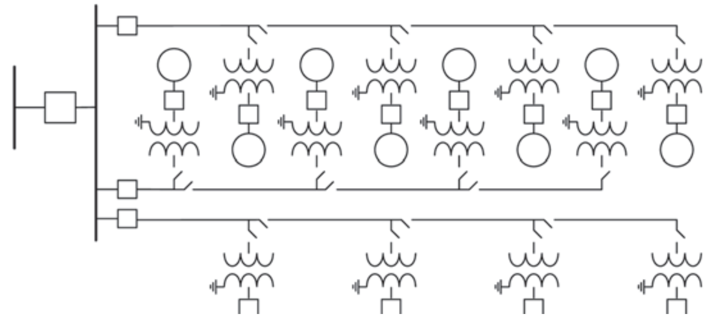

Figure 7.
Feeder-Subfeeder

Looped feeder topologies provide a higher level of availability when compared to the others. It allows continued production in the event of single component failures. Faults in the WTG tower or between towers can be isolated, allowing the remaining WTGs to continue production.

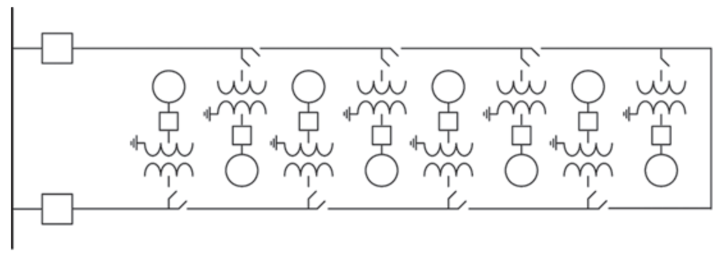

Figure 8.
Looped Feeder

5. Limitations of Typical Windfarm Topology

All windfarm topologies have an inherent limitation common to the collector bus – feeder arrangement. The windfarm topology is connected to a collector bus and stepped up to transmission level voltage through a power transformer. The windfarm feeders rely on the substation transformer neutral-ground connection for a reference ground for the medium voltage collector system. The WTGs cannot provide a reference ground because of the WTG transformer delta connection. A grounded WYE connection would introduce multiple sources of ground fault current that will complicate the ground fault protection and desensitize the IED at the substation.

If a feeder circuit breaker opens during operation, then that feeder and the operating WTGs will become isolated and form an ungrounded power system. This condition is especially troublesome if a phase-to-ground fault develops on the feeder; a scenario that causes the unfaulted phase voltages to rise to line voltage levels. It should be pointed out that a feeder ground fault is the most commonly anticipated fault type for on-shore windfarms that use overhead lines for the feeders. This fault can also result in severe transient overvoltages, which can eventually result in failure of insulation and equipment damage.

Under Normal Conditions
$V_A=V_N\angle 90°$
$V_B=V_N\angle -30°$
$V_C=V_N\angle -150°$

Grounded System under A-G Fault Conditions
$V_A=0$
$V_B=V_N\angle -30°$
$V_C=V_N\angle -150°$

Isolated System under A-G Fault Conditions
$V_A=0$
$V_B=\sqrt{3}\cdot V_N\angle -60°$
$V_C=\sqrt{3}\cdot V_N\angle -120°$

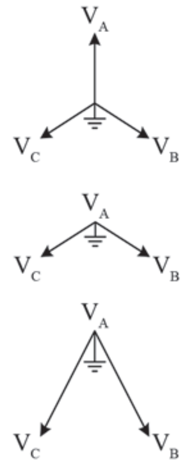

Figure 9.
Relationship for Normal and Fault Conditions

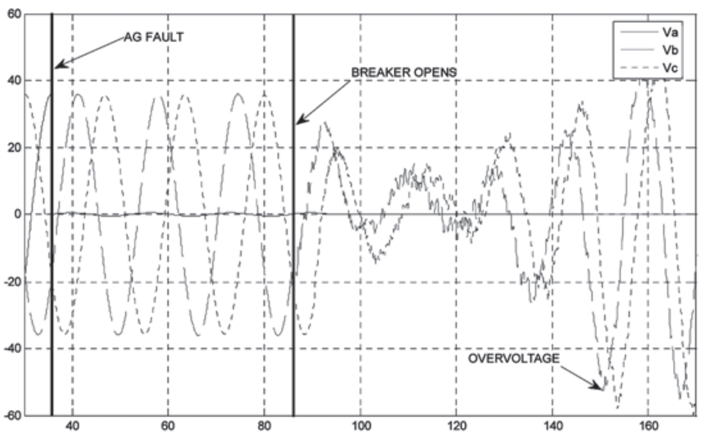

Figure 10.
Simulation of Feeder Overvoltage During a Ground Fault

Ignoring this condition could produce eventual failure of a cable or WTG transformer. One remedy is to design for the ungrounded system. This results in increased costs due to the higher voltage ratings, higher BIL, and added engineering. Another solution is to install individual grounding transformers on each feeder. This adds to equipment and engineering costs and increases the substation footprint.

6. Coordinated Fault Clearance via Transfer Tripping

An alternative solution is to disconnect the WTGs from the feeder before tripping the feeder breaker. However, the IED protecting the feeder in the substation is the only IED that can selectively detect feeder faults. In this case this IED would then send a transfer trip to all WTGs on the feeder. Once all units are disconnected, opening of the feeder breaker results in a well-behaved collapse of the voltage. Opening of the feeder breaker would be delayed minimally to ensure coordinated tripping.

7. Transfer Trip Implementation

The proposed method for implementation of the transfer trip solution is IEC61850 GOOSE messaging over a fiber-optic Ethernet network. This solution supports critical signaling to multiple IEDs. IEDs connect directly to the network, removing the need for expensive teleprotection equipment. Windfarms are often designed to include an integral network of optical fiber. Off-the-shelf Ethernet switches are available that can be configured to the existing fiber layout and can easily accommodate the distance between IEDs. As an added benefit, fiber-optic media provides excellent immunity to noise or ground potential differences.

Adoption of the IEC61850 protocol allows the same communication path to be utilized to transmit a variety of additional data. Examples of this information include control commands between devices for issuing of trip from other substation protections, commands to preclude a device from otherwise tripping (blocking), interlocking the control of a device with status of another device, event and diagnostic information (such as waveforms and event logs), and analog information (such as current and power metering).

This protocol supports several important features that make it an appropriate choice for this application. Any data items in the IED that are available via IEC61850 are structured according to the protocol and include standardized descriptions of the source and type of the data. The IEC GOOSE message carries a "user defined" dataset. The dataset can be configured with IEC61850-modeled data items. The methodology promotes ease-of-configuration and interoperability between various manufacturers IEDs.

GOOSE is a multicast message that, once transmitted can be received by any device on the network that needs it. A feature supported in the IEC GOOSE is the ability to restrict the flow of data to a particular broadcast domain through the creation of a Virtual Local Area Network or VLAN. This dataflow restriction is achieved by adding 4 bytes to the Ethernet data frame per the IEEE802.1Q standard (Figure 8). A 2-byte Tag Protocol Identifier identifies the extended data frame. The other 2 bytes include 12 bits for a VLAN ID, 3 bits for priority encoding of the Ethernet message, and one bit for backward compatibility with Token Ring. Once identified as an extended Ethernet frame, a switch in the network can decode the VLAN ID or VID. This ID is read by the network device and "switched" to those ports programmed with the same VLAN ID.

Another area addressed by the IEC GOOSE is that of Ethernet Priority. Ethernet communication has been traditionally described as "non deterministic" in that the possibility of collisions on the wire made it difficult to determine the delivery time of the message. The use of Layer 2, full-duplex switch technology now prevents the occurrence of Ethernet collisions. Switches receive all messages and store then forward them to the destination locations as required. It is possible for a single port in the switch to have several messages queued for delivery to a device. This would add a certain amount of delay in the processing of a message. Ethernet Priority, however, removes this delay. Upon receipt of an Ethernet message with a "high priority", the message is moved to the front of the queue and becomes the next message to be sent to the receiving device thereby minimizing the transmission time of the message.

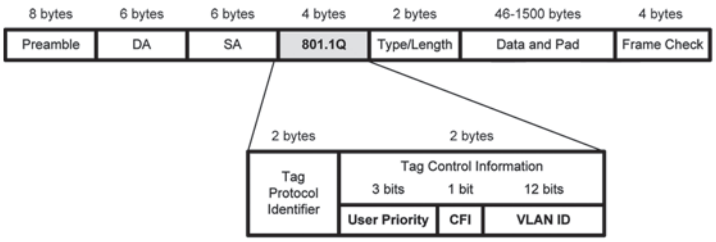

Figure 11.
Extended Ethernet Frame

The diagram below shows how the IEC61850 network topology would be deployed for a larger, radial windfarm;

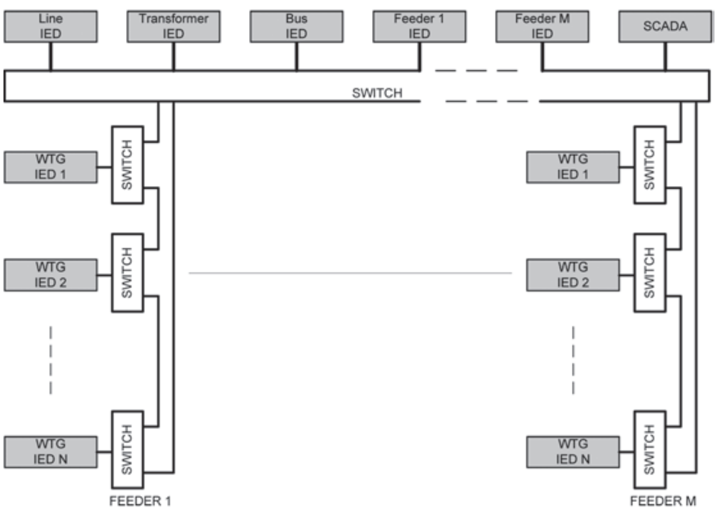

Figure 12.
Windfarm Communications Network Topology

Each wind turbine has a multifunction protection IED that would provide electrical fault protection for the generator and tower cable, as noted above. In addition to providing "local" protection for wind turbine equipment, the WTG IED features IEC61850 protocol support so as to provide the transfer trip capabilities.

The physical arrangement of the components of the windfarm dictates a network arranged in a ring-architecture for each feeder. In an Ethernet network, it is not permissible to have more than one path to a particular device. Therefore ring topologies could not be configured with early generation switches. However the latest generation of Ethernet switches provides support for Rapid Spanning Tree Protocol (RSTP). RSTP enabled switches exchange information to ensure that only one switch provides a path to a device. If a failure occurs in the enabled path, the switches will automatically reconfigure the network to re-establish a path to the device in as little as 5 milliseconds. The ring topology allows for the failure of any one path with no loss of communications to any device. A single switch failure results in the loss of communications to only one device. However, its peers on the network will quickly detect the loss of this device. This would allow the IEDs to automatically adapt to the communications failure. For instance The WTG IED could enable voltage tripping only in the case that communications with the feeder IED is lost.

8. Transfer Tripping Performance

Table 1 illustrates timing sequence for a feeder fault using the transfer trip solution. The timing analysis above assumes a breaker clearing time of 60 ms. The time required to process and transmit the GOOSE message across the network is 8 ms. Tripping of the feeder breaker by the IED is delayed by 30 ms to ensure that all of the WTGs are disconnected prior to clearing the fault. The Ethernet switches present a negligible time delay and is not included in Table 1.

Event #	Description	Time (ms)
1	Feeder Ground Fault	0
2	Feeder IED detects fault and send transfer trip	32
3a	WTG IEDs receive transfer trip & operate	8
4a	WTG breakers open	60
	WTG clearing time	**100**
3b	Feeder IED time delay	30
4b	Feeder breaker opens	60
	Feeder clearing time	**122**

Table 1.
Transfer Trip Timing

Another application would be for the WTG IED to issue a "block" command upon detection of a fault condition within the wind turbine transformer or tower cable. If such a fault occurs, the potential to cause nuisance tripping on the feeder can occur. IED2, as seen in Figure 1, provides protection for the wind tower transformer and cable, and can simultaneously trip the MV breaker as well as send a block command to the feeder IED located in the substation. This block command allows for the feeder to stay on-line and avoids disconnecting the remainder of the WTGs.

In addition to transfer trip and blocking commands, the network architecture also enables the windfarm operator to take advantage of the detailed diagnostics and metering capabilities inherent in the WTG IEDs. The current generation of microprocessor based protective IEDs contain detailed event logs, current/voltage waveform recorders, metering and other diagnostic information that prove valuable in the diagnosis of fault and system disturbances.

9. Summary

It has been demonstrated in this paper that there are aspects of a windfarm configuration that require consideration when designing the protective system. One important aspect is the need to disconnect the WTGs before isolating the feeder during a ground fault. A novel method has been presented that achieves this, alleviating the need for a grounding source on each feeder. This reduction in equipment translates into increased system reliability as well as significant cost savings for the windfarm operator. This solution makes extensive use of GOOSE messaging and leverages pre-existing system components, specifically fiber Ethernet between wind turbines, industrialized Ethernet switches and IEC61850 compliant IEDs. GOOSE messaging can also be extended to various other protection, automation, and operational applications.

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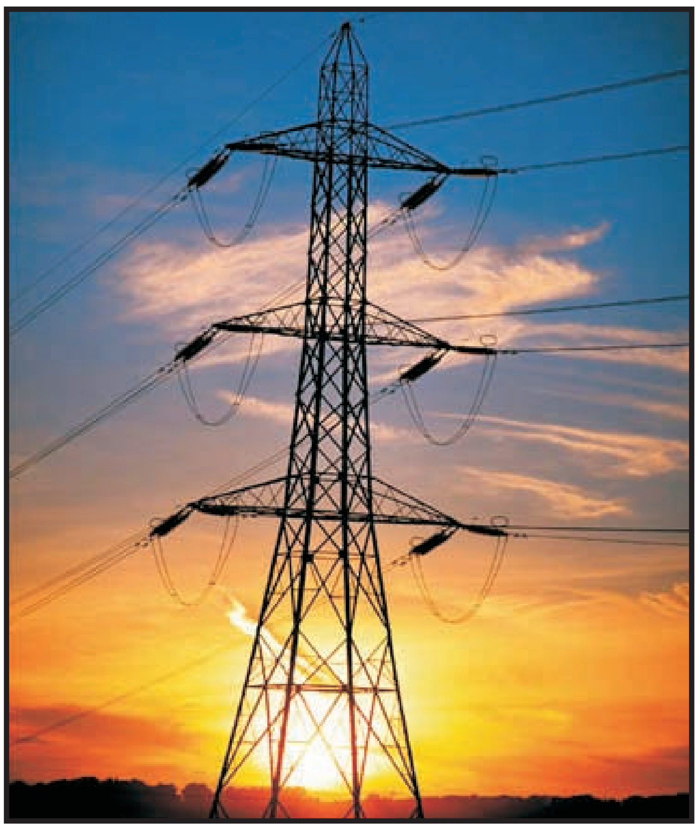

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Protection of Phase Angle Regulating Transformers Using Digital Relays

Lubomir Sevov
GE Multilin

Craig Wester
GE Multilin

1. Abstract

Phase Angle Regulating transformers are dynamic changers, used to control the real power flow through interconnected power systems. This paper describes the specifics of an installed Phase Angle Regulating (PAR) transformer, and protection techniques using modern digital relays. More specifically, the paper is focused on issues applying current differential protection to a 120 MVA Phase Regulating Transformer on 138kV power system at CLECO's Beaver Creek 138/34.5 kV substation in Pineville, Louisiana.

2. Introduction

The PAR's are used to control active and/or reactive power flow based on varying the phase angle between the source and load voltages. The PAR controls the power by inserting regulated quadrature voltage in series with the line to neutral voltage of the series unit. The inserted quadrature voltage is derived from phase to phase voltage of the other two phases. There are different PAR types, depending on their application and construction: with, or without Load Tap Changer (LTC), Delta/Wye, or Wye/Wye exciting unit configuration, with or without voltage regulating winding. They also differ by power and voltage ratings to provide different phase angle regulation, and hence power flow. The one described in this paper is of conventional type with Series Unit secondary winding connected in Delta, and Wye/Wye connected windings of the Exciting Unit with grounded neutral. The Load Tap Changer is located on the secondary Wye connected winding of the Exciting unit, and is used to control the magnitude of the quadrature voltage, used to shift the Load phase to ground voltage, from the one of the Source side.

The power flow between the Source and Load sides of the PAR can be approximated by the following equation:

$$P = \frac{V_S * V_L * \sin\Theta}{X}$$, where

where P is real power flow per unit, V_S is phase to ground voltage of the Source side, V_L is per unit voltage of the Load side, Θ is phase angle between V_S and V_L voltages, and X is per unit reactance between the Source and Load sides.

3. PAR at Beaver Creek Substation

Power flow studies indicated, that under certain conditions, the loss of the Rodmacher – Montgomery 230kV line (Figure 1), causes the 138/115kV autotransformer and the 115kV line to exceed their ratings of 93MVA, and 122MVA respectively. The Beaver Creek autotransformer is an interconnection point between CLECO and Entergy. CLECO owns the autotransformer and the 115kV bus.

Four alternatives were investigated:

1. Install series inductive reactors - not preferred, since it does not give the flexibility to increase reactance as the system conditions change, and physical substation property not large enough to accommodate, since additional property can't be purchased.

2. Install a 138kV Phase Angle Regulator transformer in CLECO's substation and leave existing Beaver Creek autotransformer.

3. Replace existing autotransformer with Phase Angle Regulating transformer.

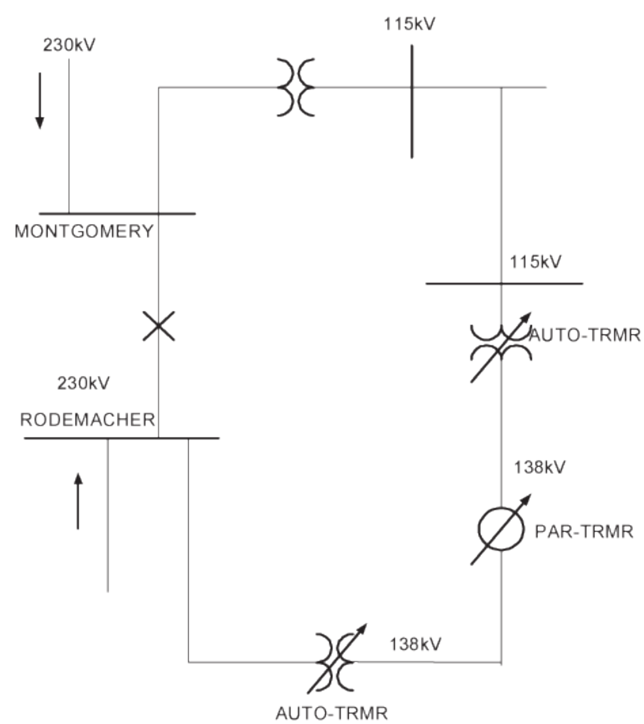


Figure 1.
Rodmacher - Montgomery 230kV line

4. Replace existing Beaver Creek 138/115kV autotransformer and re-conductor the 115kV line - viable alternative, but not preferred due to cost in excess of 10 times the cost of alternative 2 or 3.

Therefore, the installation of a Phase Angle Regulator transformer at Beaver Creek appeared to be most economical solution. (Option 2)

The current electrical configuration consists of a 230kV line in parallel with a 138/115 kV autotransformer and 115kV line. In situations in which the 230 kV line is carrying power from southern part of the service territory to the northern part of the service territory, loss of the 230 kV line may cause the flow on the 138/115 kV autotransformer to exceed the current carrying capacity of the 115 kV line. Therefore, the purpose of this PAR is to limit the power flow through CLECO's Beaver Creek 138/115KV autotransformer and the 115kv line for loss of the 230 kV segment in order to avoid limiting transfer capability as well as possible damage to the autotransformer and conductor.

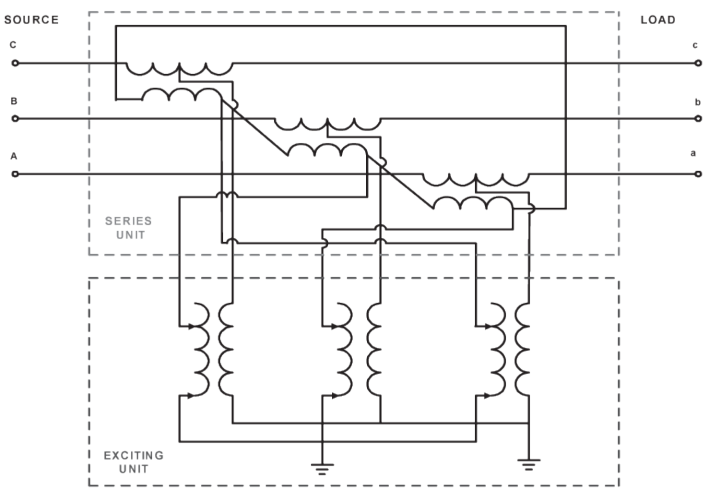


Figure 2.
PAR configuration

4. Phase Angle Regulator - Protection

4.1 Electromechanical-type Differential Protection

In the past, the differential protection for the PAR (Figure 2) would require six single phase electromechanical-type transformer differential relays – three for the primary differential system – 87P, and another three for the secondary differential system – 87S. A single phase differential electromechanical relay is set to respond on per-phase differential current, that may result from summation of the electrically connected source, load and exciting unit primary currents, as part of the primary differential protection. A single phase differential electromechanical relay is also set on per phase basis, and respond on differential current, that may appear during internal for the series and exciting unit secondary winding faults, as includes the source, load and exciting unit secondary winding currents. To set electromechanical relays for protection of the primary differential system, no special treatment is required, as it is similar to providing differential protection on the autotransformer. However, applying electromechanical relays for protection of the secondary differential system, Figure 3 would require the load and source side CTs to be connected in delta, interposing auxiliary CTs for magnitude compensation, etc.

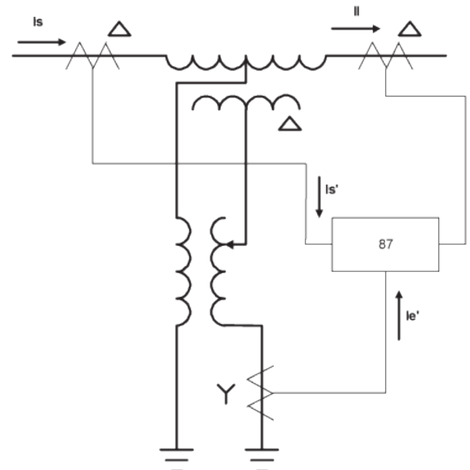


Figure 3.
87S Differential Protection

4.2 Digital Differential Relay Protection

Used for protecting this PAR are two three-phase current differential protection relays – one for primary differential system 87P, and another for secondary 87S.

4.3 Primary Differential Protection - 87P.

Biased differential protection is set to protect the common primary series unit winding and the primary exciting unit winding. The summation of the currents forming the operating differential current (Figure 4) can be expressed by the formula: $\bar{I}_S + \bar{I}_L + \bar{I}_{Exciting} = 0$, where $\bar{I}_S$ is per-phase primary source side current, $\bar{I}_L$ is per-phase primary load side current, and $\bar{I}_{Exciting}$ is per-phase current from the primary winding of the exciting unit.

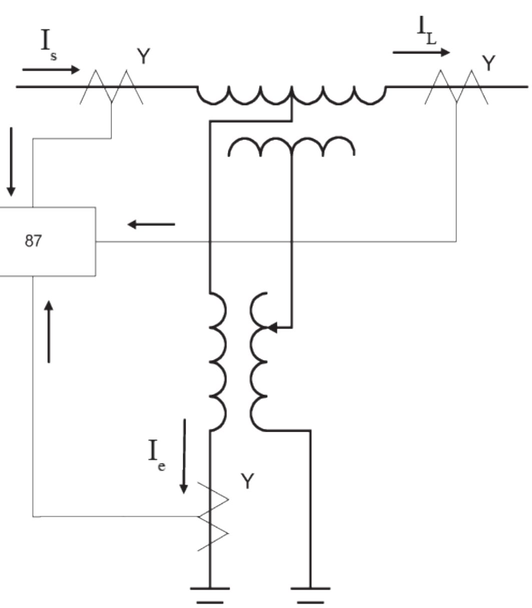


Figure 4.
87P Differential Protection

One digital three-phase current differential relay provides 87P protection, and no special treatments are needed. The CTs on the source, load and excitation unit primary sides can be connected in wye, and they can have different ratios. These modern relays perform automatic magnitude and phase compensations, zero sequence removal, harmonic and DC filtering, and provide more robust protection capability. Advanced relay differential algorithms cope with different techniques in computing and utilizing the restraining current, as to accomplish better selectivity, security and sensitivity.

4.4 Secondary Differential Protection - 87S

The secondary differential relaying system includes per-phase source and load currents, as well as the exciting unit secondary winding current. This protection differs from the one applied on conventional power transformer, as the current on the secondary winding of the exciting unit, appears as a vector sum of the per-phase source and load currents. The relationship among these three currents is kept through any angle variation of the PAR. To understand how the current on the secondary winding of the exciting unit is actually produced, see Figure 5. The secondary winding from the series unit is connected in Delta, where for example the exciting current for phase A - $\vec{I}'ea$, is derived from the source and load phase B and C currents. The primary currents, flowing through the wye connected CTs of phase A, are designated as:

$\vec{I}sa$ - phase A current source side

$\vec{I}la$ - phase A current load side

$\vec{I}'ea = \frac{k}{2}[(\vec{I}sc+\vec{I}lc)-(\vec{I}sb+\vec{I}lb)]$ - phase A exciting current, where $\vec{I}sb, \vec{I}lb, \vec{I}sc, \vec{I}lc$ are source and load currents of B and C, and k is series unit turns ratio.

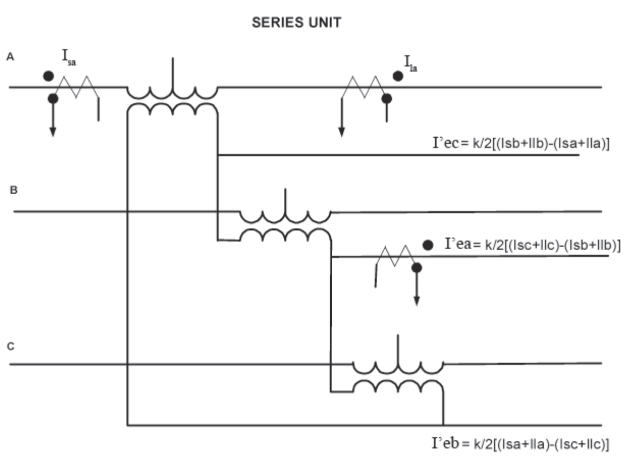


Figure 5.
Secondary Currents for 87S Protection

In Figure 5, the exciting current I 'ea is derived from the source and load currents of the other two phases - B and C. Therefore, to set the digital current differential relay correctly, we shall define their phase and magnitude relationships.

The currents used by the relay to provide 87S protection of phase A, therefore are: $\vec{I}sa_{relay} = \vec{I}sa / n1$ from source side CT, $\vec{I}la_{relay} = \vec{I}la / n2$ from load side, and $\vec{I}'ea_{relay} = \vec{I}ea / n = K[(\vec{I}sc+\vec{I}lc)-(\vec{I}sb-\vec{I}lb]/2n$ - from the exciting unit secondary winding current. All CTs are rated at 1200:5, and therefore have the same $n = n1 = n2 = 240$ ratio.

Simplifying the formulas of expressing the differential and restraint currents used by the relay, having the same CT ratios, allows us to omit n1, n2 and n:

$\vec{I}da = \vec{I}sa + \vec{I}la + k[(\vec{I}sc + \vec{I}lc) - (\vec{I}sb + \vec{I}lb)]/2$ - differential current of phase A.

$\vec{I}db = \vec{I}sb + \vec{I}lb + k[(\vec{I}sa + \vec{I}la) - (\vec{I}sc + \vec{I}lc)]/2$ - differential current of phase B, and

$\vec{I}dc = \vec{I}sc + \vec{I}lc + k[(\vec{I}sb + \vec{I}lb) - (\vec{I}sa + \vec{I}la)]/2$ - differential current of phase C.

The differential algorithm set in the relay uses per-phase "maximum of" current on per phases basis for restraining signal, and in this case it is defined as:

$$\vec{I}ra = \max\left\{|\vec{I}sa|, |\vec{I}la|, |\vec{I}'ea|\right\}$$
$$\vec{I}rb = \max\left\{|\vec{I}sb|, |\vec{I}lb|, |\vec{I}'eb|\right\}$$
$$\vec{I}rc = \max\left\{|\vec{I}sc|, |\vec{I}lc|, |\vec{I}'ec|\right\}$$

Further on, per phase differential and restraint currents are plotted on a pre-configured dual-slope, dual breakpoint characteristic (Figure 6), for tripping /no tripping decision.

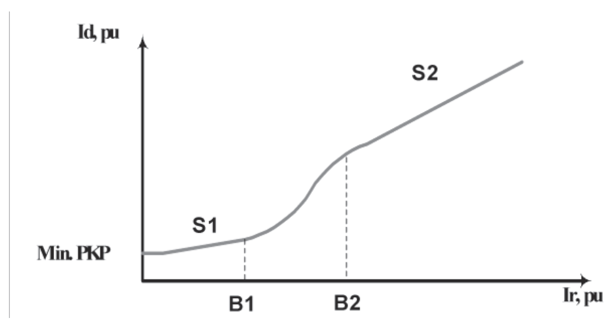


Figure 6.
Dual Slope, Dual Breaker Characteristic

The characteristic is defined by differential pickup setting, S1 and S2 as slope 1 and slope 2, and B1, and B2 as breakpoint 1 and breakpoint 2 settings.

When no phase angle is introduced between the source and load phase to ground voltages and respectively currents, the PARs tap changer is in neutral position, and no quadrature voltage is impressed to the line voltage. In this mode, the exciting current has the largest value (Figure 7).

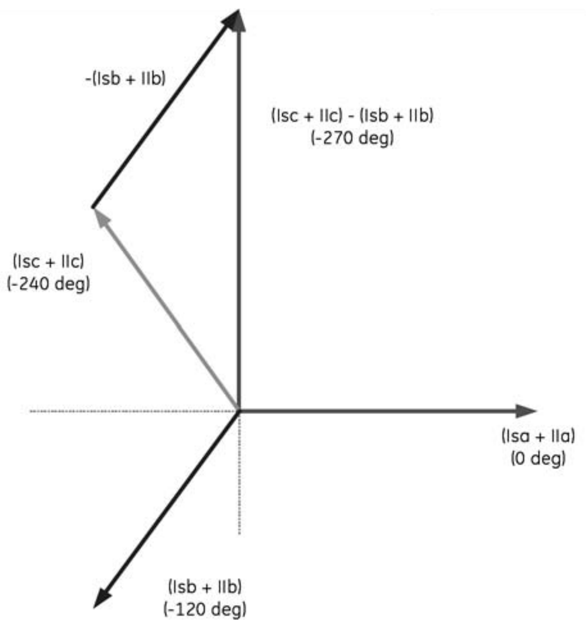
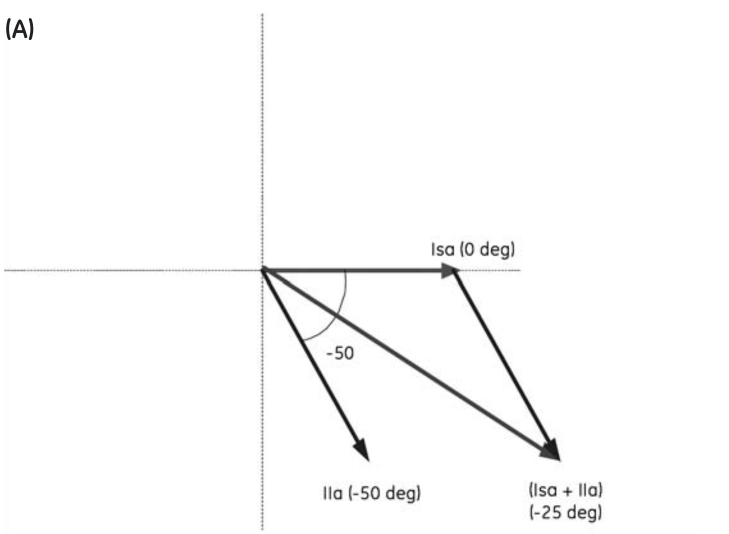
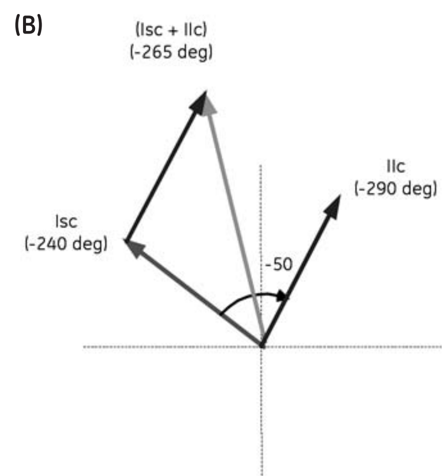


Figure 7.
Source and Load Currents in Phase, and Exciting Current 90° Out of Phase.

The exciting current has the smallest value, when the source and load currents are displaced by the maximum angle, the PAR can control. The one installed at Beaver Creek substation is rated for maximum of ± 50° degrees phase shift. Figures 8, 9, show the steps of summing per phase source and load currents, when 50° degrees apart, and the direction of the resultant current during this conditions.





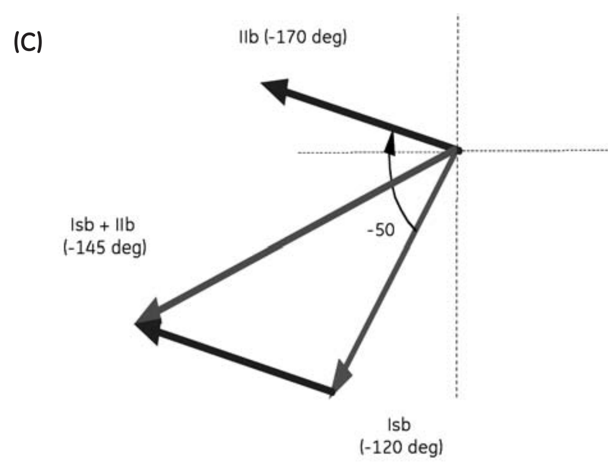


Figure 8.
Summation on per phase Source and Load Currents

Figure 9 a) shows the phase relationship of all three summated currents, when source and load currents are displaced on 50°, and b) shows the resultant excitation current with respect to phase A sum. It can be noted, that the excitation current again makes a 90° degrees angle with the resultant vector of source and load phase A currents.

PAR Series unit:

Rating: 120 MVA, 138kV/138kV

Angle Variation: +/- 50 degrees

Series unit rating: 67.579-53.387 kV Delta Winding

Exciting unit:

Exciting unit rating: 124.974Y-53.387Y kV

% Impedance:

Z1 = Z2 = 7.41% @ 0° phase shift @ 120 MVA

= 16.63% @ full phase shift @ 120 MVA

Z0 = 7.41% @ 120 MVA

Current Transformers:

(1200 :5) , wye connection.

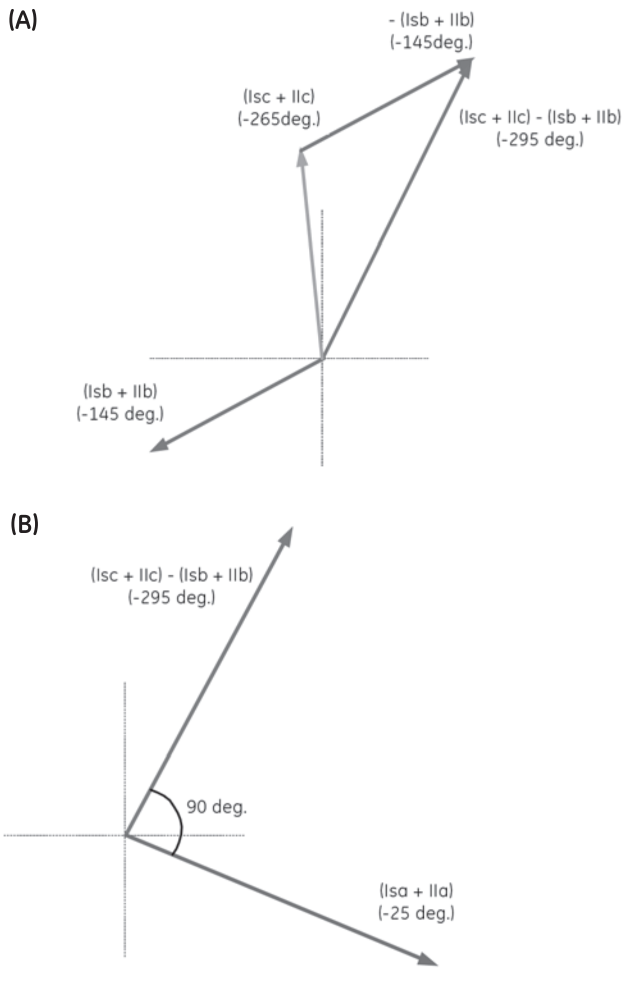


Figure 9.
Summation on per phase Source and Load Currents

Based on PAR data, the nominal currents of source and load sides of the series winding are equal to 502∠0° primary Amps or 2.09 Amps secondary. The excitation current at 0o phase shift is therefore equal to 1100 ∠- 270° Amps primary, or 4.556∠-270° Amps secondary. To obtain zero differential current, we need to adjust the magnitude of the excitation current to (2.09+2.09) = 4.18 Amps and in 180° direction, or the magnitude of the source and load summated current to 4.556 Amps. Providing that the settings of the CT in the relay match exactly the field CT, to obtain correct magnitude compensation factor by which to multiply the currents from source and load sides, the setting of the phase to phase voltage for the exciting unit winding had to be changed. The relay automatically determines the reference winding and CT, by selecting them per winding and CT setup, based on smallest ratio between CT primary and rated winding load. In this case, the compensation of 1.09 = 4.556/4.18 was applied to the source and load currents, and the entered phases to phase voltage for the exciting winding, was decreased to 138kV*(4.18/4.58) = 125.8kV, providing magnitude compensation factor of 1 as automatically selected by the relay as a reference. Performing the calculation for magnitudes of the secondary currents for phase A relay terminals, results in 2.09*1.09=2.278 Amps source and load secondary currents, or their sum equal to 4.556 Amps. The CT polarities and connections should be taken carefully into consideration, when selecting the correct exciting winding shifts. As per Figure 7, the angles for source and load windings, were set to 0° degree and the exciting winding to -270° degrees. Here, the balance was achieved, when the LTC was on neutral position. From Figure 9 b) it can be concluded that the angle phase relationship remains unchanged, during any phase shift, meaning the –270° degrees was the correct angle set in the relay for excitation winding currents. The insertion of quadrature voltage Q V into the line voltage, will be at its maximum, for 50° degrees phase shift, and it is equal to:

$$V_Q = (138kV/\sqrt{3})*(2*\sin\tfrac{50^\circ}{2}) = 67.33kV$$

The series unit ratio is calculated as K = 67.579kV / 53.387kV = 1.265, meaning that a voltage of 67.33kV / 1.265 = 53.22 kV must be applied to the secondary of the series unit transformer, to produce 50° phase shift. The Beaver Creek's PAR is equipped with 33 tap LTC, which provides angle change of 3.125° degrees per tap or quadrature voltage of 53.22/16 =3326 V per tap.

4.5 Over-excitation

As seen from PAR data, the rated series winding voltage is lower than the line voltage, and as such is subject to over-voltage or over-excitation conditions during external faults, which may produce saturation, and cause false 87S operation. The care in such situations is taken by computation of 5th harmonic on per-phase differential current, which inhibits the differential protection. Additional logic can be built, to allow a V/Hz protection to take a lead under such conditions. The saturation of the series winding has no impact on the 87P differential protection, as all three input currents, are measured from electrically connected circuits.

4.6 Sensitive ground fault protections

The series and exciting unit primary windings can be effectively protected during ground faults that may not be detected by the 87P protection, by applying Restricted Ground Fault (RGF) protection. The RGF is designed to detect even small internal ground fault currents, and at the same time provide security on external ones, using a restraint current based on variable symmetrical components parameters. The neutral of the exciting unit secondary winding, is also solidly grounded, and is a source of zero sequence current, where a ground over-current protection 51G can be set to detect phase to ground faults.

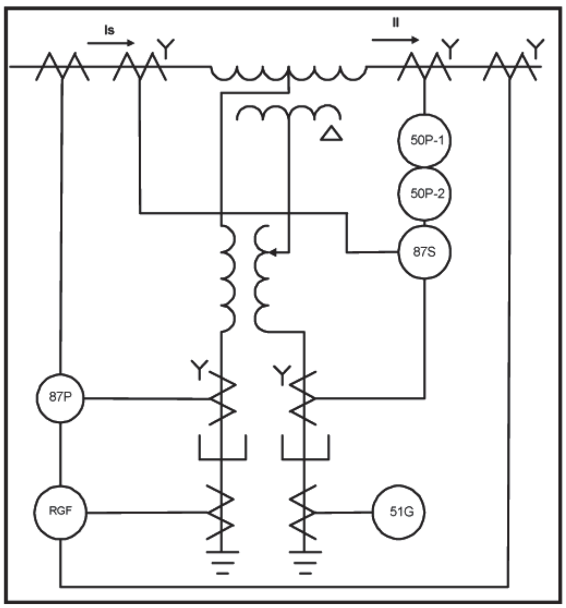


Figure 10.
Ground Fault Protection

5. References

[1] "Protection of Phase Angle Regulating Transformer" IEEE Power System Relaying committee, 1999

[2] "Power Transformer" Principle and Applications, J Winders, 2002

[3] GE Publication GEK-106416, Transformer Management Relay, Instruction Manual

0626-v4

Practical Experience in Setting Transformer Differential Inrush Restraint

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1. Abstract

The second harmonic inrush restraint function of transformer differential relays maintains security of the differential protection during transformer inrush events. The typical setpoint for the second harmonic restraint is the relay manufacturer's default or recommended setting of 20% of fundamental current, with some adjustment based on operating experience. However, some operating situations may result in levels of second harmonic current lower than 20% during inrush, and levels may be as low as 5%. This lower level of second harmonic current requires a lower inrush restraint setting that may impact the tripping time of the differential element for fault conditions. In addition, inrush restraint is typically performed on a per-phase basis, so a loss of security is possible if inrush restraint performs incorrectly on only one phase of the protected transformer.

This paper provides several examples of actual events where loss of security occurred due to incorrect settings of the second harmonic restraint function, or due to mis-application of cross-phase blocking. Based on the information from these events, the paper directly discusses considerations and recommendations for setting the second harmonic restraint to maintain security during transformer inrush including a discussion of traditional and adaptive inrush restraint techniques. The paper also includes recommendations on when to apply cross-phase blocking techniques such as 1-out-of-3 blocking, 2-out-of-3 blocking and average restraint blocking methods.

A key message from this paper is the use of the actual inrush characteristic of the protected transformer to determine optimum setpoints for the differential relay. Microprocessor relays have the capability to, and should, capture waveforms every time a transformer is energized. This data should be analyzed to check the adequacy of the existing second harmonic restraint settings, to ensure no loss of security occurs.

2. Introduction

Florida Power & Light Company (FPL) is in the process of replacing existing transformer protection panels at select locations on the FPL transmission system. The existing panels use electromechanical or solid-state differential relays, and the new transformer protection panels will use microprocessor relays with a standard configuration. As part of the design process for these protection panels, FPL is also developing a standard for transformer protection settings.

The basic protection for these transformers is differential protection. Second harmonic restraint is used to block the differential element during inrush events for the transformer. The standard protection settings will include a recommendation for the selection of the inrush restraint function and the settings for this function. Also, these settings will determine whether to use the inrush restraint function on a per-phase or multi-phase basis.

To develop the standard settings for the inrush restraint function, FPL used an experimental laboratory procedure along with actual operating experiences. A relay was configured to some inrush restraint function, level setting, and cross-phase blocking method. These settings were then tested against simulated and actual fault events, by playing oscillographic records back through a test set to the relay. These tests were repeated using different setpoints and different restraint functions until a standard setting that meets FPL's operating criteria was determined. This standard package of settings was confirmed by capturing transformer in-rush records from various installations and comparing the setpoint levels to actual second harmonic levels to confirm there is enough margin.

One of the drivers for this process is an effort to eliminate misoperations of transformer differential relays due to low second harmonics on inrush without sacrificing protection capabilities. Misoperations can occur during the energization of a transformer due to failure of the harmonic restraint function. A digital fault recorder oscillographic record that captures this type of harmonic restraint failure was used for the testing later in this paper. This fault record shows a failure due to the low levels of harmonic current produced during an energization. An external fault can also trigger a misoperation during the voltage recovery period, causing the differential relay to operate immediately after a fault is cleared from the system.

3. Review of differential protection principles

Differential protection is a fast, selective method of protection against short circuits in transformers, and is the standard protection used by FPL to protect transformers. Differential protection is a practical application of Kirchhoff's current law. The sum of the currents entering the transformer should equal the sum of the currents leaving the transformer. Differential protection adds the measured currents entering and leaving the transformer to create a differential current.

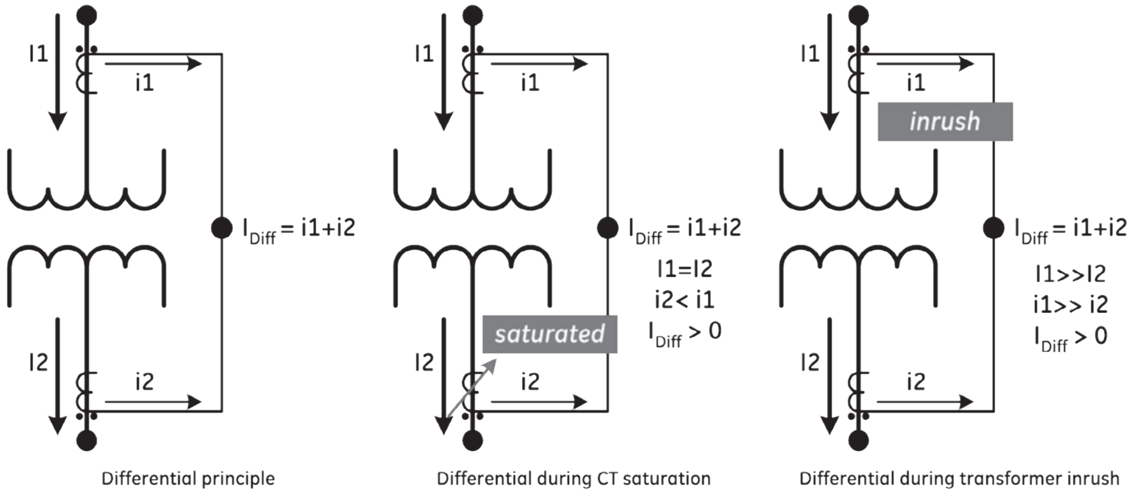


Figure 1.
Transformer Differential Protection Principle

With the ideal transformer of Figure 1, and assuming ideal CTs, the differential current is zero when current is flowing through the transformer. A differential current greater than zero indicates an internal fault condition. In practice, the differential current for a normally operating transformer is always greater than zero due to CT measurement error, the position of the load tap changer, and other factors introducing noise into the measurement signals. Therefore, the sensitivity of the protection is reduced slightly to account for these errors.

There are two common situations where differential protection may incorrectly declare an internal fault condition. One condition is CT saturation for a fault outside of the transformer zone of protection. The error in the measurement signal of the saturated CT results in a significant error in the differential current. The erroneous differential current may result in undesired operation of the differential element for an external fault condition. This type of event is beyond the scope of this paper.

The second common situation is a transformer inrush event. Some operating situations instantly change the operating flux of the transformer core, requiring a large supply of current. This inrush of current typically occurs in only one winding of the transformer. Therefore inrush currents may produce a differential current that results in the operation of the differential protection. This type of event is not a fault condition, so the differential protection should restrain from operating for this condition.

4. Transformer Inrush Phenomena

To properly set a protection function, it is necessary to have a basic understanding of the power system events the function is intended to detect. To set the inrush restraint function for transformer differential protection requires some understanding of transformer inrush events, including the causes and characteristics of these events. This section of the paper defines a transformer inrush event. The section continues on to discuss how power system conditions influence the severity and characteristic of the inrush event, and finishes by describing the common power system events that cause transformer inrush.

4.1 Definition of Magnetizing Inrush Current

A transformer inrush event is actually magnetizing inrush current. The windings in a transformer are linked magnetically by the flux in the transformer core. The exciting voltage drives the flux in the core. An increase in the exciting voltage therefore increases the flux. To maintain this additional flux, which may be in the saturation range of the core steel of the transformer, the transformer draws more current which can be in excess of the full load rating the transformer windings. This additional current is the inrush current necessary to supply the magnetizing branch of the transformer. [1]

To show magnetizing inrush current graphically, consider the equivalent circuit of transformer shown in Figure 2. In an ideal transformer (with a 1:1 turns ratio), the currents I1 and I2 are equal except for the small current flowing through the shunt element of the magnetizing branch. The increase in flux caused by an increase in the exciting voltage draws more current through the magnetizing branch. When the transformer is being energized, this current flows through only one winding. In this example, the current I1 is the inrush current. During inrush events other than energization, the magnetizing inrush current may appear in both windings, with the inrush current more prevalent in one winding. Remembering the differential current is, then in any inrush event, the magnetizing inrush current results in a differential current. This differential current can lead to operation of the differential protection. Figure 3 is an example of magnetizing inrush current and the resulting differential current.

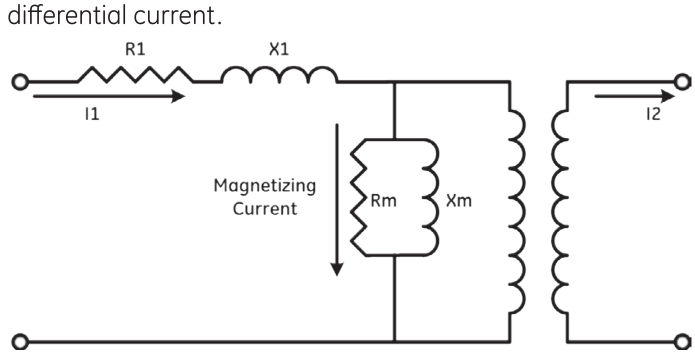


Figure 2.
Transformer Equivalent Circuit

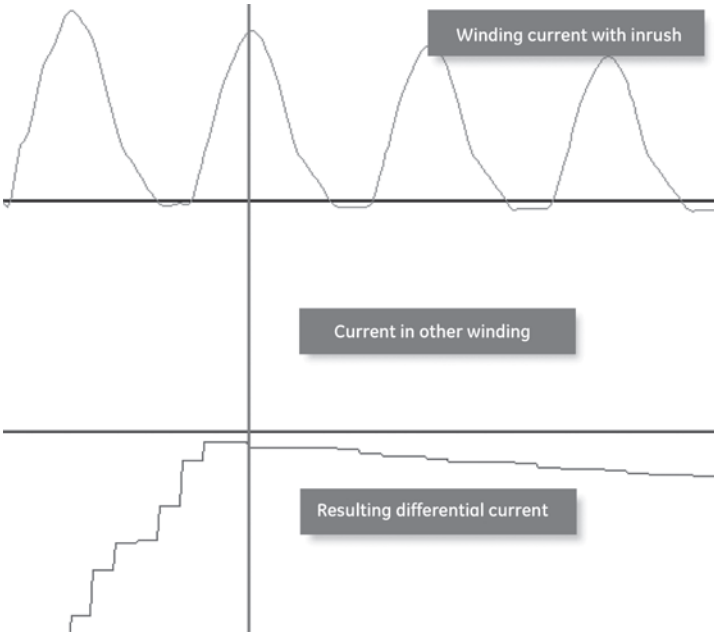


Figure 3.
Inrush Current and Resulting Differential Current

A review of AC excitation of magnetic materials helps understand the actual characteristic of magnetizing inrush current. The magnetic steel used in transformers has a large number of regions (known as "domains") with a specific magnetic moment. An external magnetizing force causes all the magnetic moments of the steel to align with the applied magnetic field. In the case of transformers, the excitation voltage provides this applied magnetic field. The alignment of the magnetic moments causes an increase in flux density greater than that of the external magnetic field. The steel is fully saturated when all the magnetic moments are aligned with the applied field. Once the external field is reduced, the magnetic moments maintain a net magnetization component along by the direction of the field. This effect results in magnetic hysteresis of the steel.[2] Transformers use grain-oriented electrical steel, where the domains tend to produce directions of magnetization with high permeability and low core loss.

Figure 4 shows the exciting voltage e, the core flux φ, and the exciting current iφ, of a transformer. The figure also shows the flux and exciting current mapped to the corresponding magnetic hysteresis loop. The excitation voltage drives the flux in the core.

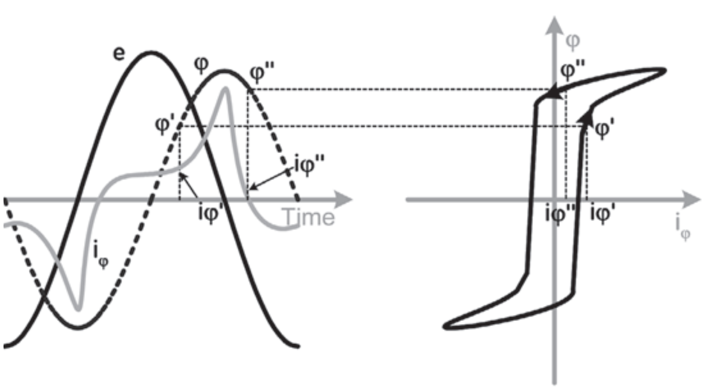


Figure 4.
Transformer Core Excitation Phenomena

The exciting current is needed to produce the magnetic field. The waveform of the exciting current varies from the sinusoidal waveform of the flux due to the non-linear magnetic properties of the core.[2]

The waveforms and hysteresis loop shown in Figure 4 are typical for a transformer that is in service supplying load. The flux requirement is very small, therefore, the exciting current is very small. Now consider what happens when the excitation voltage increases. This voltage drives an increase in the flux in the core. The flux characteristic is still sinusoidal in shape. The flux may be shifted in respect to the 0-axis due to the point on the wave when the excitation increases and the amount of remanent flux in the core. This flux may be high enough to cause saturation of the transformer core. The hysteresis loop becomes negligible for this case, as shown in Figure 5. The resulting current, the magnetizing inrush current, needed to supply the flux is very high in magnitude, and may approach the magnitude of fault currents. The magnetizing current will eventually decay due to losses in the circuit.[3]

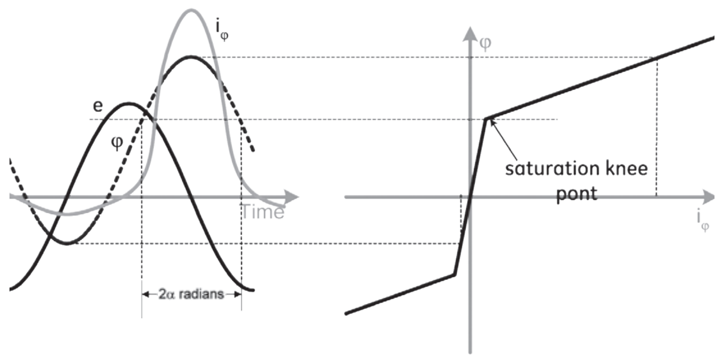


Figure 5.
Flux and Exciting Current Hysteresis during Core Saturation

When the transformer core is in saturation, the exciting current is part of a sine wave for the period that the flux exceeds the saturation knee point of the core. The exciting current is essentially zero for the rest of the power system cycle. This results in the classic waveform signature of magnetizing inrush current, as shown in Figure 6.

The magnitude and characteristic of the inrush current is dependent on the amount of saturation of the transformer core. There are several factors that influence the likelihood the transformer core will go into saturation.

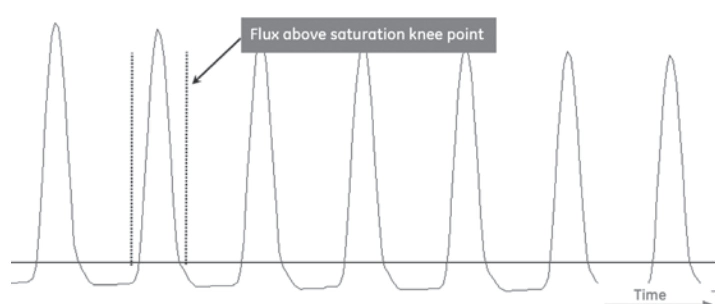


Figure 6.
Magnetizing Inrush Current Characteristic

4.2 Point on Wave

The key factor in determining the magnitude of the magnetizing inrush current is the point on the voltage wave when the excitation voltage increases. If the excitation voltage is defined by

$e(t) = E_{\max} \cos(\omega t - \theta)$, then the flux is defined by

$\varphi(t) = \varphi_{\max} \sin(\omega t - \theta) + \varphi_{\max} \sin(\theta)$.

Where $e(t)$ = instantaneous excitation voltage,
E_{max} = peak exciting voltage,
ω = system frequency,
θ = voltage angle θ defined in Figure 7,
$\varphi(t)$ = instantaneous flux,
φ_{max} = peak flux.

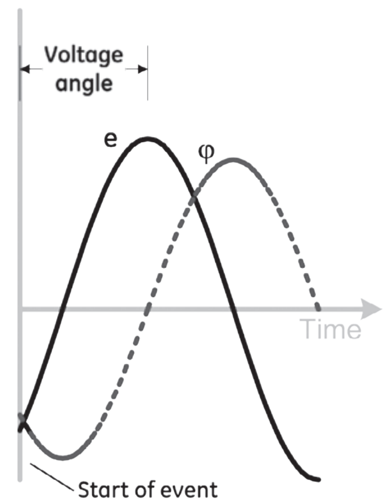


Figure 7.
Voltage Angle during Magnetizing Inrush

It is obvious that the flux is offset with respect to the 0-axis based on the voltage angle θ. When the voltage angle θ is 90°, the flux is fully offset. There is no offset when the voltage angle θ is 0°. Maximum saturation of the transformer core occurs when the flux is fully offset at the 90° voltage angle. [3]

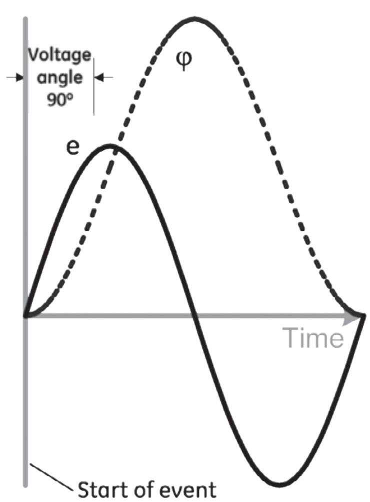


Figure 8.
Exciting voltage and flux at 90° voltage angle

4.3 Remanent Flux

When a transformer is de-energized, some level of flux remains in the transformer core. This level of remanent flux is the flux in the core when the exciting voltage is removed. The actual value of the flux is based on the alignment of the magnetic moments of the steel, and can be found from the magnetic hysteresis loop of the transformer core. The remanent flux may therefore be positive or negative in value, and is typically 30% to 80% of the maximum flux of the core. When the transformer is energized, this remanent flux is added to the flux driven by the exciting voltage. The flux equation therefore becomes

$$\varphi(t) = \varphi_{\max} \sin(\omega t - \theta) + \varphi_{\max} \sin(\theta) + \varphi_{remanent}$$

, where $\varphi_{remanent}$ is the remanent flux in the core.

The flux characteristic during an inrush event is then offset with respect to the 0-axis. Depending on the sign of the remanent flux, the transformer core may be more or less likely to go into saturation. The impact of the remanent flux is removed once the core is fully saturated.

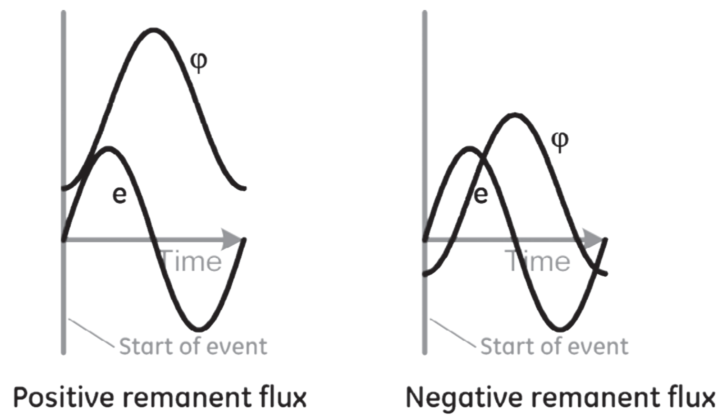


Figure 9.
Excitation Voltage and Flux at 90° Voltage Angle with Remanent Flux

4.4 Transformer Design and Magnetizing Inrush Current

The design of the power transformer influences the likelihood that the transformer core will saturate during inrush events. A transformer core is built from thin strips of high-grade electrical steel called laminations. The laminations are electrically isolated by a thin coating of insulation, and then stacked or wound to create the core section. The flux density of the steel, the design of the core, and the method of connecting the laminations all impact the amount and characteristics of the magnetizing inrush current.

Over the last few decades, there are some changes in transformer design that impact the second harmonic ratio during magnetizing inrush. The standard transformer design typically uses M-6 conventional grain-oriented electrical steel. M-6 steel has a saturated flux density of 1.8 Teslas, the highest of any magnetic material. This very magnetically efficient steel results in lower exciting currents and therefore lower inrush currents. However, this has been the standard core material in transformer design for many years. Some transformers are now designed using high-permeability (High-B) electrical steel. High-B steels provide more consistent grain orientation, resulting in a more linear magnetic hysteresis loop.

A more important change has been in the construction of the core. Laminations were stacked on top of each other, resulting in an air gap between each lamination. The air gap increases the reluctance of the core, thereby reducing the magnetic efficiency of the core. Laminations are now constructed such that they overlap each other to provide a continuous path for the flux. This construction reduces the reluctance in the core, and therefore increases the flux density and reduces the exciting current.

The other significant change in transformer design is based around the economic concerns of loss evaluation. The trend is to select transformers based on loss evaluation. To limit losses, transformers are designed with lower maximum flux densities. The flux density is limited by using a core with a larger cross-sectional area. The relation between maximum flux density and the exciting current is given by the following equation:

$$E_{rms} I_{\varphi,rms} = 4.44 f A_c l_c B_{\max} H_{rms}$$

where E_{rms} = excitation voltage (rms)

$I_{\varphi,rms}$ = exciting current (rms)

f = system frequency

A_c = cross-sectional area of the core

l_c = length of core path

B_{max} = maximum flux density

H_{rms} = permeability of the core (rms)

If the excitation voltage is constant, then a transformer with a lower flux density has a lower level of exciting current. Reductions in the required exciting current lead to a reduction in the magnetizing inrush current.[4] So the combination of efficient transformer core steel, better construction of the core, and the limiting of the maximum flux density, leads to lower exciting currents and lower magnetizing inrush currents.

4.5 Power System Impedance

The physical installation of the transformer also influences the magnetizing inrush current. The exciting voltage at the transformer is the system source voltage minus the voltage drop across the system impedance. As the source impedance decreases, indicating a stronger source, the magnitude of the inrush current increases. The resistance of the system is also a major contributor to the decay of the inrush current over time. The change in flux over time is defined by

$$\Delta\varphi = \int_{t}^{t+T} (R \times i)\,dt$$

where $\Delta\varphi$ = flux change per cycle,

R = total series resistance including transformer winding resistance

T = period of one cycle.

The flux in the transformer due to the inrush event begins to decay immediately by this amount, and decays until steady-state magnetizing flux is reached. As the flux controls the magnetizing current, the current also decays to steady-state magnetizing levels.[5]

4.6 The Characteristics of Transformer Inrush Current

As previously described, the classic inrush restraint current is similar to that of Figure 10. The non-linear nature of the magnetizing inrush current results in harmonics being present. It is possible to estimate the level of these harmonics by using Fourier series analysis on the magnetizing inrush current. The flux is above the saturation knee point for a total angular span of 2α radians. During this span, the exciting current is a portion of a sine wave. During the rest of the power system cycle, the exciting current is essentially 0.

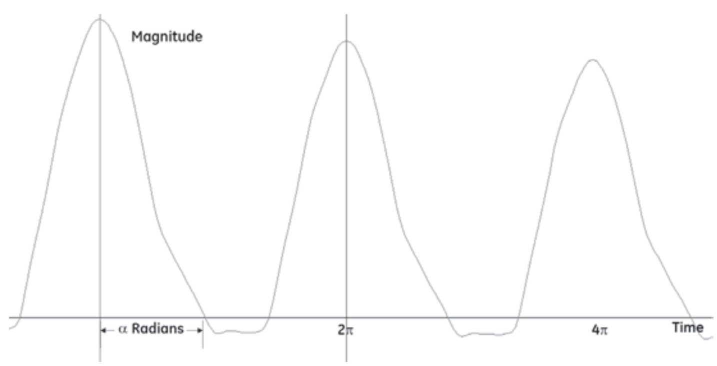


Figure 10.
Inrush Current Characteristic

This Fourier analysis shows that the second harmonic is the predominant harmonic during transformer inrush events and is commonly used as the basis for inrush restraint functions. As the saturation angle a increases, the exciting current becomes more linear and the ratio of second harmonics to fundamental decreases.[3] This means, in effect, the more severely the transformer core is saturated, the more linear the magnetizing inrush current.

Setting the midpoint of the first peak to time t=0, a cosine Fourier series may be used to calculate the second harmonic current and fundamental frequency component. Assuming the exciting current is truly symmetric, then the second harmonic ratio will be as high as 70.5% when $\alpha = \pi/3$ radians, and will be 17.1% when $\alpha = 2\pi/3$ radians.[3]

4.7 Summary of Transformer Inrush Phenomena

Transformer inrush occurs whenever the excitation voltage on the transformer increases. Increasing the excitation voltage increases the flux in the transformer core, and therefore requires more current from the system to supply the flux. The new level of flux, and the period of the power system cycle the transformer core is in saturation determine the characteristics of the inrush current. The flux is offset based on the point on the voltage wave when the change in excitation occurs, and directly influences the level of saturation of the transformer core. Remanent flux in the core also initially offsets the flux in the core. The design and location of the transformer also impact the amount of saturation of the transformer core.

Of more interest for protection purposes are the characteristics of transformer inrush current. The common techniques for preventing the operation of differential elements for inrush events use the linearity of the differential current signal. The ratio of second harmonic current to the fundamental current is often used. The more linear the inrush current, the less second harmonic current is present. Therefore, as the level of core saturation increases, the ratio of second harmonic current to fundamental current decreases.

5. Events that result in Magnetizing Inrush Currents

Any event on the power system that causes a significant increase in the magnetizing voltage of the transformer core results in magnetizing inrush current flowing into the transformer. The three most common events are:

Energization of the transformer. This is the typical event where magnetizing inrush currents are a concern. The excitation voltage on one winding is increased from 0 to full voltage. The transformer core typically saturates, with the amount of saturation determined by transformer design, system impedance, the remanent flux in the core, and the point on the voltage wave when the transformer is energized. The current needed to supply this flux may be as much as 40 times the full load rating of the transformer, with typical value for power transformers for 2 to 6 times the full load rating.[1] The waveforms of Figure 3 were recorded during energization of a transformer.

Magnetizing inrush current during fault clearing. An external fault may significantly reduce the system voltage, and therefore reduce the excitation voltage of the transformer. When this fault is cleared, the excitation voltage returns to the normal system voltage level. The return of voltage may force a dc offset on the flux linkages, resulting in magnetizing inrush current. This magnetizing inrush current will be less than that of energization, as there is no remanent flux in the core.[3] The current measured by the differential relay will be fairly linear due to the presence of load current, and may result in low levels of second harmonic current.

Sympathetic inrush. Energizing a transformer on the power system can cause sympathetic magnetizing inrush currents to flow in an already energized parallel transformer. Energizing the second transformer causes a voltage drop across the resistance of the source line feeding the transformers. This voltage drop may cause a saturation of the already energized transformer in the negative direction. This saturation causes magnetizing inrush current to supply the flux. The magnitude of the magnetizing inrush current is generally not as severe as the other cases.[3][5][6][6]

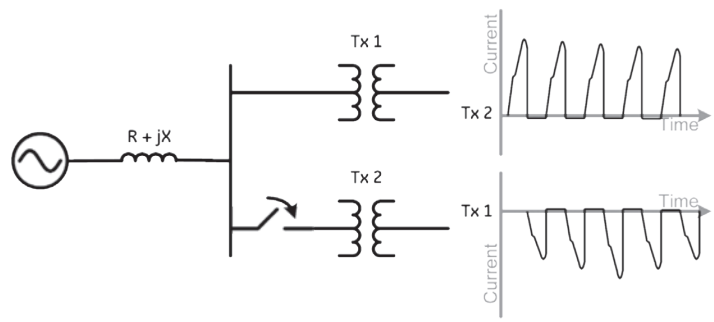


Figure 11.
Sympathetic Inrush Circuit and Waveforms

6. Transformer Inrush Restraint Methods for Differential Protection

Transformer inrush restraint functions are intended to block the differential element from operating during such an inrush event and permit the differential element to operate for internal fault events. The challenge, obviously, is that inrush current and an external fault both present a large differential current to the differential element. There are many different methods that have been proposed and implemented for restraining the differential element during a transformer inrush condition. These methods are discussed in a paper presented at this conference in 2000.[7]

FPL has already decided on a specific model of transformer differential relay for their standard protection of transformers at the transmission level. Therefore, this paper discusses only the options for inrush restraint available in this model of relay. This paper also discusses the choice of inrush restraint mode. The restraint mode determines if inrush restraint is applied on a per-phase or multi-phase basis. The inrush restraint methods available to FPL in their chosen relays are the harmonic restraint and adaptive harmonic restraint functions.

6.1 Harmonic Restraint

Harmonic restraint is the classical way to restrain tripping. There are many variations on this method. All of these methods work on the assumption the magnetizing inrush current contains high levels of second harmonic current. The current for an internal transformer fault typically has very low levels of second harmonic current. The simplest method of harmonic restraint uses the magnitude of the second harmonic in the differential current compared to the magnitude of the fundamental frequency component in the differential current. Tripping of the differential element is blocked when this ratio exceeds an adjustable threshold.

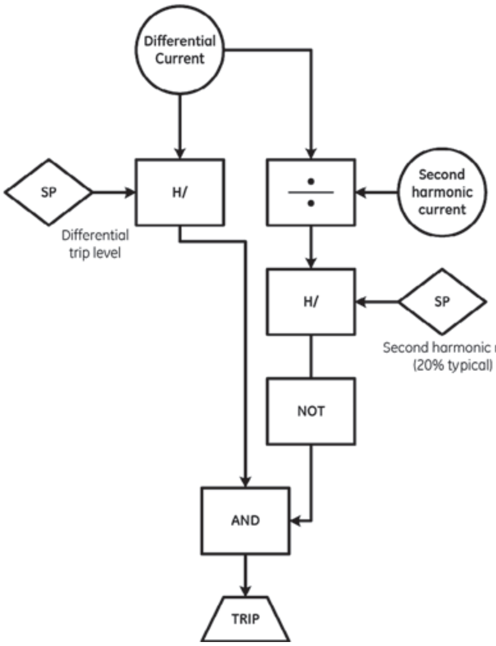


Figure 12.
SAMA Diagram for Second Harmonic Restraint

In this paper, the term "second harmonic ratio" is defined as:

$$\frac{I_{Differential\ (2^{nd}\ harmonic)}}{I_{Differential\ (fundamental)}}$$

This method originated in electromechanical relays, and has been carried through as the most common method in microprocessor relays. The harmonic restraint is typically calculated on a per-phase basis. Variations include using the RMS current as opposed to the fundamental frequency component, and using a cumulative three-phase implementation.

The historical setting for harmonic restraint is a second harmonic ratio of 20%, with an available setting range of 1% to 40%. Set too high, and the differential element may trip during transformer energizing. Set too low, and inrush restraint may block tripping during some internal fault events.

6.2 Adaptive Harmonic Restraint

Adaptive harmonic restraint is a modified version of traditional harmonic restraint that considers the magnitude and phase of the second harmonic and fundamental frequency component in the differential current. Some inrush events initially produce low levels of second harmonic in the differential current, as in the example of Figure 13. This phenomenon is an indication the remanent flux in the core initially pushes the core deeper into saturation. This low level of second harmonic current may allow the differential element to operate.

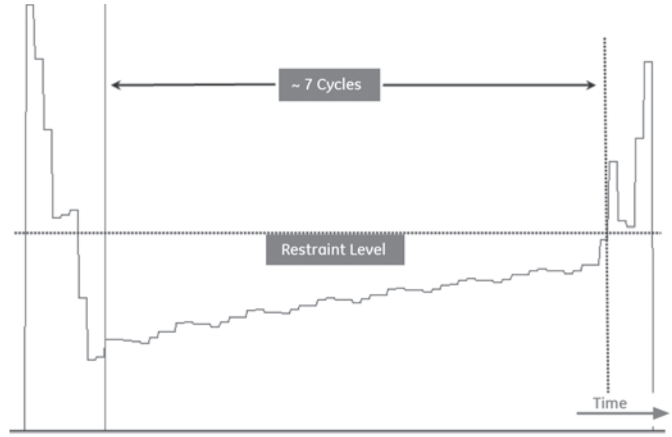


Figure 13.
Second Harmonic Current During Inrush

The adaptive harmonic restraint method dynamically changes the inrush restraint level to properly restrain the differential element for these cases. This method uses the discriminating signal:

$$\vec{I}_{21} = \frac{\vec{I}_2}{\vec{I}_1 \times e^{j\omega t}}$$

where $\vec{I}_2$ is the second harmonic differential current phasor,
$\vec{I}_1$ is the fundamental differential current phasor, and
ω is the system frequency.

The phase angle of the discriminating signal is always 90° or 270° for an inrush condition. Consider a typical harmonic restraint threshold of 20%, as plotted on the polar graph of Figure 14. The adaptive harmonic restraint initially has a lower inrush restraint threshold along the 90° and 270° axes. This threshold is dynamically raised to the default setting of 20% over a period of 5-6 cycles.[8]

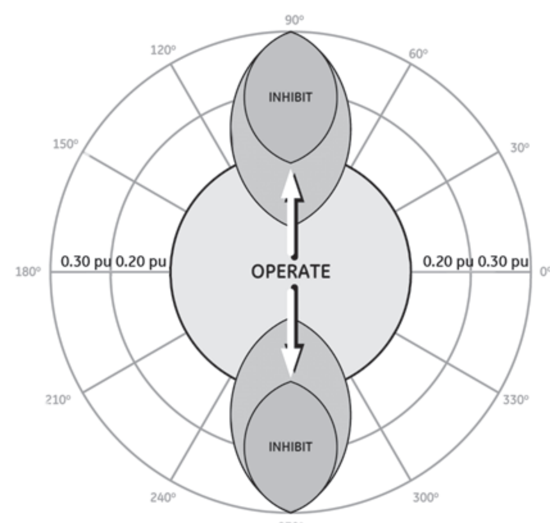


Figure 14.
Adaptive Harmonic Restraint Characteristic

The adaptive harmonic restraint algorithm successfully restrains tripping when faced with low levels of second harmonic current during an inrush event. However, this algorithm may slow tripping of the differential element by a few cycles for an internal fault if some second harmonic is present in the current.

6.3 Inrush Restraint Mode

Harmonic restraint and adaptive harmonic restraint are normally calculated individually on each phase. Typically, the operation of the differential element on any phase operates the circuit breakers supplying the transformer. If the restraint criterion is not met on any phase, the transformer may be tripped offline during energization or sympathetic inrush. Depending on the transformer installation, operating requirements, and operating philosophy, this may be acceptable performance of the differential element. However, for the standard FPL application, it is more desirable to increase the security of the differential element against inrush events by looking at inrush restraint functions in more than one phase. The inrush restraint mode is therefore the method of implementing the inrush restraint function across the entire transformer.

Per-phase. In per-phase mode the relay performs inrush restraint individually in each phase.

2-out-of-3. In 2-out-of-3 mode, the relay checks second harmonic level in all three phases individually. If any two phases establish a blocking condition, the remaining phase is restrained automatically.

Averaging. In averaging mode, the relay first calculates the average second harmonic ratio, and then applies the inrush threshold to the calculated average.

1-out-of-3. In 1-out-of-3 mode, all three phases are restrained when a blocking condition exists on any one phase. 1-out-of-3 mode typically reverts back to per-phase mode after a short time delay to allow tripping in case an internal fault occurs during energization.

These restraint modes may be explicit settings of the transformer differential element. They may also be implemented in the flexible configuration logic of the transformer protection relay.

The transformer differential protection operating for an inrush event is a loss of security. These inrush restraint modes are listed in order from the least secure to the most secure. Comparing these restraint modes to an actual transformer energization event can provide some illustration of performance. For this event, the magnetizing inrush currents during energization of the transformer were high enough to cause operation of the differential element. The second harmonic current ratios are shown in Figure 15. The B-Phase ratio is greater than 1 in this case, and is not shown on the graph. This differential element uses traditional harmonic restraint set at 20% for the inrush restraint mode. Tripping on any phase de-energizes the transformer.

Table 1 lists the performance of the various restraint modes for this example. Per-phase mode will allow the differential to operate, while all the other modes will block the differential. The correct choice is a matter of application, and a matter of operating philosophy. Per-phase mode may be the most appropriate solution for a three-phase bank made up from single-phase transformers, for example.

Restraint Mode	Result
Per-phase	Differential trips on A-phase
2-out-of-3	Differential restrains: B-phase and C-phase blocked
Averaging	Differential restrains: at t=0, =(0.05 +6.12+0.29)/3 = 2.15
1-out-of-3	Differential restrains: B-phase and C-phase blocked

Table 1.
Restraint Mode Results

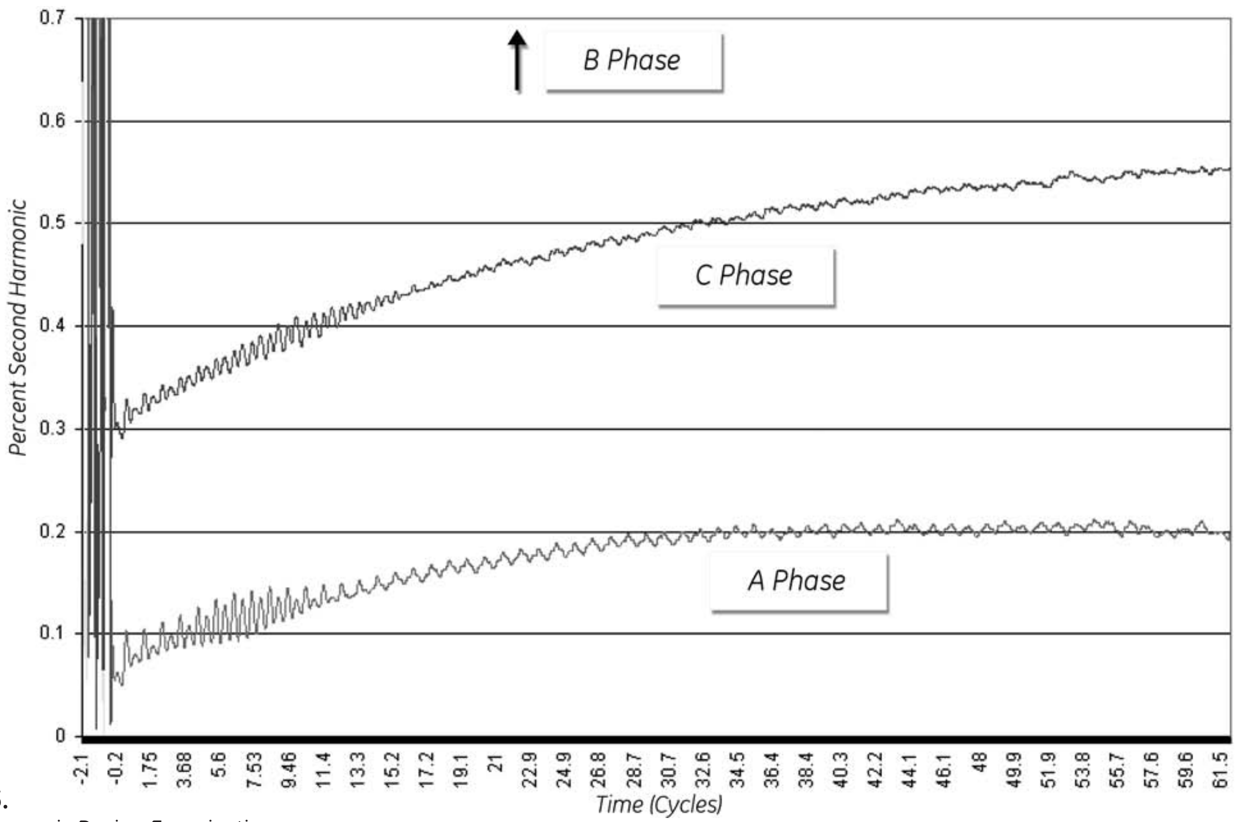


Figure 15.
Second Harmonic During Energization

7. FPL Testing of Inrush Restraint Methods

Ideally, setting the inrush restraint function for the transformer differential element is exactly like setting any other protection function. The key criteria are sensitivity and selectivity. The setting must be sensitive enough to recognize magnetizing inrush current even with low levels of second harmonics. And it must be selective to distinguish between an inrush event and other events that may produce second harmonic current.

The standard process for setting a protection function is to perform an analysis of the system. This analysis models the response of the system for various transient events to provide a basis for setting protection functions. For example, to set a distance element, the first step is to perform a short circuit analysis. The short circuit analysis is built around the known quantity of the system impedances. Different predictable scenarios are used during the analysis; basically system operating contingencies and fault location. Then some educated guesses are used for the influence of unknown variables, such as fault resistance.

A similar process can be identified for setting the transformer inrush restraint function but the results are not as predictable as short circuit analysis. The known quantity for inrush restraint analysis is that of transformer design and transformer location. There isn't any "predictable" scenario for modeling the inrush. There is only the ability to make educated guesses that relate to the type of event that causes inrush, the point on the voltage wave when this event occurs, and the amount of remanent flux in the core of the transformer. And unlike the influence of fault resistance on a short circuit analysis, there is no empirical model of a transformer for the influences of some of these factors.

Therefore there is no empirical method for determining the magnitude of inrush currents and the second harmonic ratio in the differential current. FPL used a model of the system and transformer to produce some digital representation of inrush events, and also used oscillography captured during transformer inrush events to develop settings using an experimental process.

A protective relay that FPL has selected for use in the transformer protection panel provide the following options:

Inrush restraint function: harmonic restraint
adaptive harmonic restraint

Inrush restraint mode: per-phase
2-out-of-3
averaging

In addition, the 1-out-of-3 inrush restraint mode can be implemented using the flexible configuration logic of the relay.

This test procedure uses wye-connected CTs that are typical on new installations using microprocessor-based differential relays. Delta-connected CTs complicate inrush restraint settings. The currents measured by the relay are phase-phase currents. The subtractive effect of the delta connection may actually decrease the second harmonic current seen by the relay and require a lower setting on the inrush restraint function.[9]

Therefore, the concern for setting the inrush restraint function is the ratio of the second harmonic current to the fundamental current. Having some guidelines that predict this ratio will help develop inrush restraint settings that are sensitive and selective.

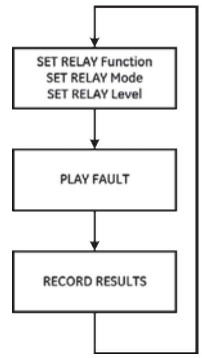


Figure 16.
FP&L Test Procedure

To determine the most appropriate choice for the inrush restraint method and the inrush restraint mode, a simple bench test experiment was devised. The procedure was to simply choose some settings for the relay, connect the relay to a three-phase test set, and play several oscillography files through the relay.

The oscillography file of Figure 17 shows a misoperation of a differential relay caused by low levels of second harmonic current during energization of an autotransformer. This transformer is a bank of 3 single-phase 500MVA, 500kV/230kV autotransformers, and was energized from 500kV.

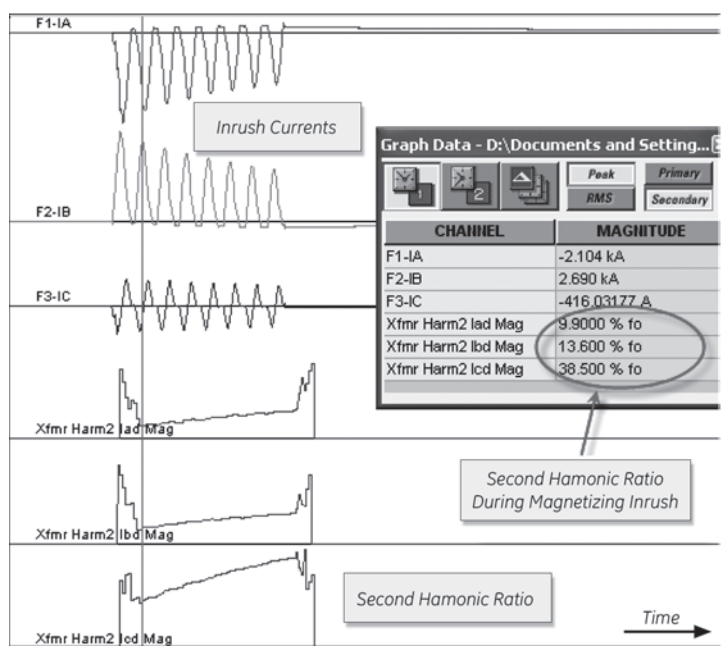


Figure 17.
Oscillography File used for Test Procedure

Before beginning the testing, FPL set the following criteria for acceptable settings.

- A minimum level setting for harmonic restraint of 15%.
- No operating time delay for the differential element is introduced by the selected inrush restraint function or inrush restraint mode.
- The differential element is blocked from operating during this actual energization event.

Based on these criteria, the adaptive harmonic restraint function and the 1-out-of-3 restraint modes were not tested. The adaptive harmonic restraint function could possibly slow tripping of the differential element for internal faults where CT saturation could occur. The 1-out-of-3 mode must be implemented in the flexible configuration logic of the relay. The concern is this logic may introduce a time delay when blocking the differential element. Also, FPL would like to avoid custom logic for protection functions as much as practical.

7.1 Test Results

The more detailed test procedure is shown in Figure 18. The initial setpoint for the inrush restraint level was 20%. If the differential element tripped at this level, the level was then reduced to 15%. If the differential element continued to trip, the level was reduced until restraint was achieved. The results of the test are tabulated in Table 2.

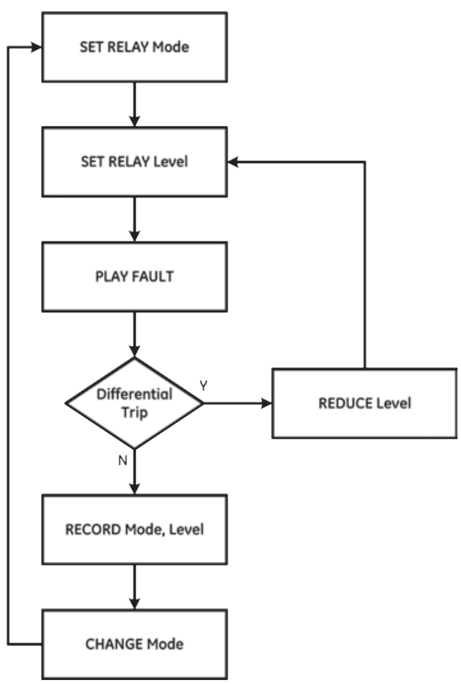


Figure 18.
Detailed Test Procedure

These results match the expected results for the different inrush restraint modes. No level was recorded for the per-phase option, as a review of the fault data indicated the level would be 10% or less. This is an unacceptably low setting. Using the averaging mode, the differential element was blocked at 20%. The inrush restraint level was raised until a trip occurred to give some idea of the margin between blocking and tripping for the differential element.

Mode	Level to achieve blocking
Per-phase	No level recorded
2-out-of-3	13% (Trips at 14%)
Averaging	20% (Trips at 21%)

Table 2.
Harmonic Restraint Test Results

8. Conclusions

The traditional settings for inrush restraint for transformer differential protection are to use harmonic restraint in a per-phase mode, with a restraint level of 20%. Experience shows that for most transformer protection applications these settings provide high-speed clearing of transformer faults and proper restraint for inrush events. For a few applications, lowering the harmonic restraint setting, employing cross-blocking techniques, or a combination of both may be necessary to ensure that transformer energizations occur successfully where very low second harmonic inrush levels are present. Capturing energization records to confirm where these techniques may need to be employed is essential.

Based on operating experience, FPL has some transformer protection applications where the traditional inrush restraint settings are not adequate. For some of these applications, FPL plans to use either 2-out-of-3 or averaging mode, to provide greater security. A setting of 15% provides a good margin of security for energization of the transformer where the second harmonic current may fall to low levels. The belief is these settings will also successfully restrain the differential element when faced with a fault recovery magnetizing inrush event.

There may be some concern when setting the inrush restraint level to 15% or lower. CT saturation during internal faults may result in the protection relay seeing a high second harmonic current ratio and incorrectly restraining. Setting an unrestrained differential element between 8 per unit and 10 per unit provides confidence the transformer protection will trip for an internal fault even at a lower setting for the inrush restraint.

FPL has used this process to guide the development of inrush restraint settings. The limited experience to date with intelligent consideration of the settings has been successful. The following event records are from two different transformer locations that used these settings. The transformers in both cases had previously been energized, so remanent flux was present in the transformer core. Figure 19 is for a 560MVA, 230kV/138kV three-phase autotransformer, energized at 230kV. Figure 20 is for a 224MVA, 230kV/138kV autotransformer, energized at 230kV.

Setting the inrush restraint function takes some knowledge and experience. The transformer design and the system impedance have some influence on the magnitude and severity of the inrush event. Capturing oscillography data for every energization event for a specific transformer may be used to generalize about the characteristics of inrush currents for a specific transformer. If a transformer seems to provide low levels of second harmonic

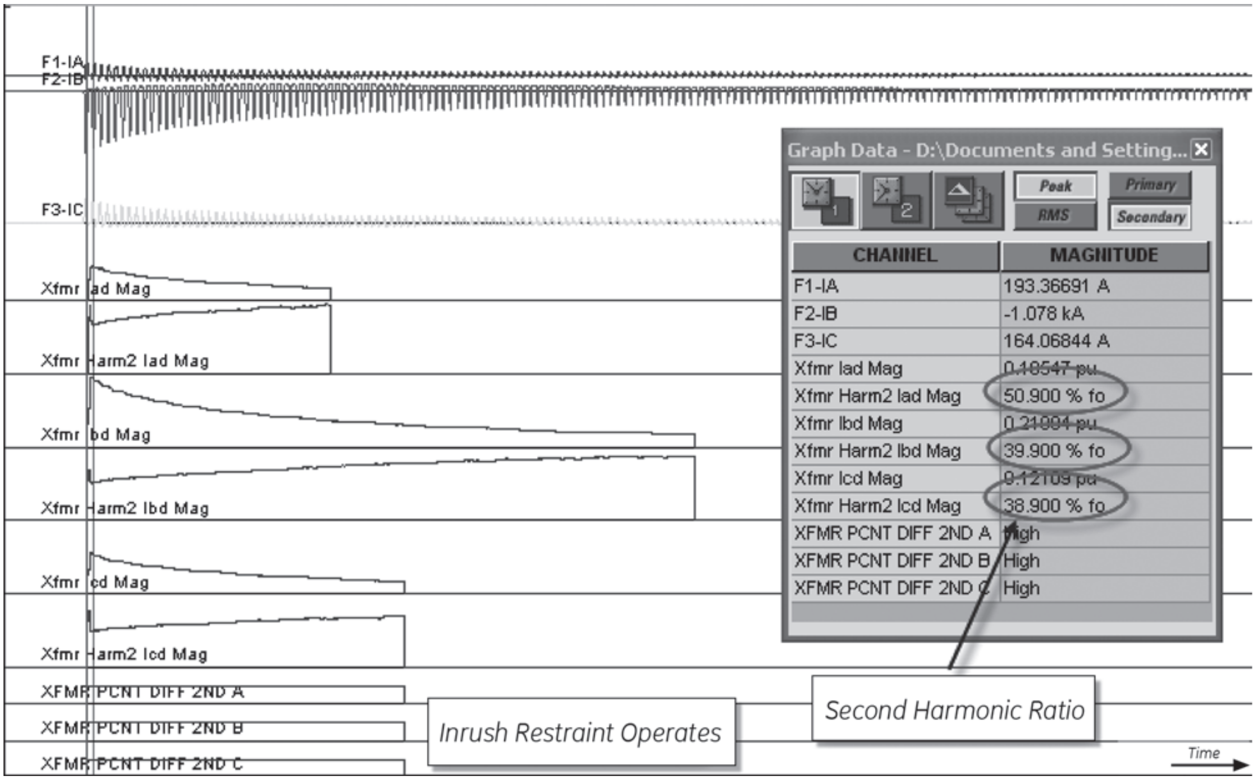


Figure 19.
Energization of One Autotransformer

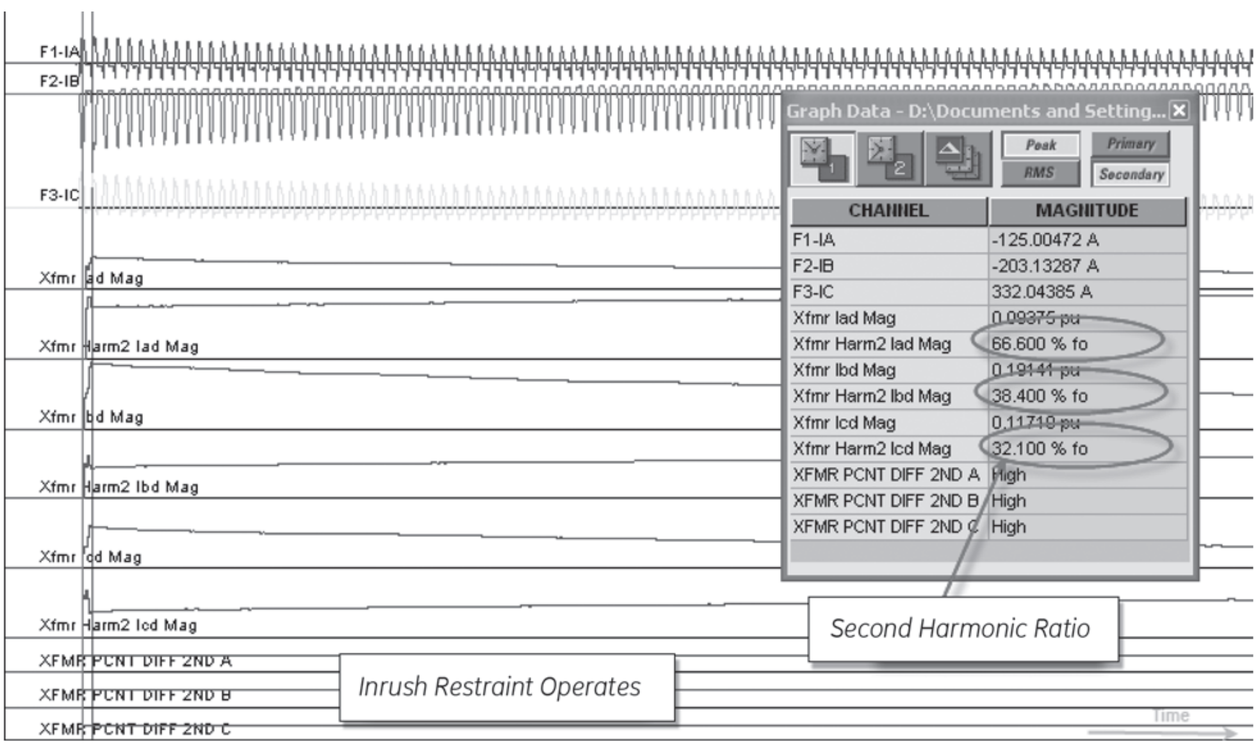
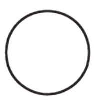
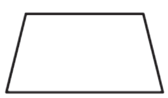


Figure 20.
Energization of a Second Autotransformer

current over a number of events, it may be necessary to lower the inrush restraint functions or to use adaptive harmonic restraint. FPL plans to capture and analyze oscillography data on every energization of a specific transformer to develop the operating history for a specific transformer.

9. Symbols

The process control industry has developed symbols and diagramming formats to represent both linear and non-linear processes. The symbols and diagramming format are commonly known as "SAMA diagrams", as they were originally a standard developed by the Scientific Apparatus Makers Association. Though the Scientific Apparatus Makers Association has declared the original standard obsolete, and no longer permits the direct association of the organization name with the industry standard, these symbols, and the term "SAMA diagram", are still in common use in the process control industry. These symbols will grow increasingly useful as protection systems migrate from traditional protection and control to automatic process control.

Symbol	Function
	Measuring
	Setpoint
	Automatic Signal Processing
	Final Controlling

Symbol	Function
H/	High signal monitor
÷	Dividing
NOT	Inverter
AND	Logical AND

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Motor Protection Principles

1. Introduction

Three phase motors can be classified into two types: induction and synchronous. An induction motor consists of two parts: the stator and the rotor. The stator core is built of sheet-steel laminations that are supported in a frame.

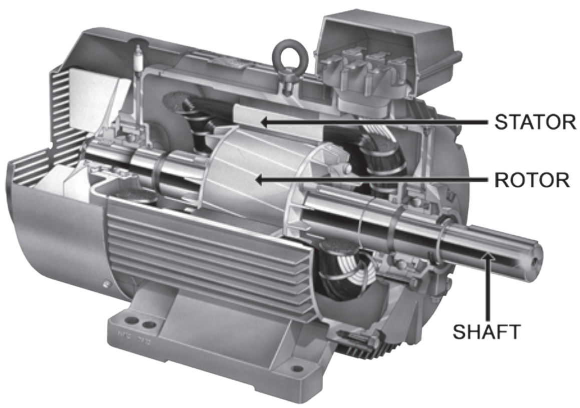


Figure 1.
3 phase AC Motor

The windings are placed in the stator slots 120 electrical degrees apart. Windings may be connected in "star" (or wye) or delta configuration.

The rotor of the induction motor is made of a laminated core with conductors placed parallel to the shaft. The rotor conductors are embedded in the surface of the core and are not insulated from the core, because rotor currents follow the "least resistance" path. The rotor conductors are shorted by end rings at both ends.

Any motor failure will have the following cost contributors: repair or replacement, removal, installation and loss of production. Most of the motor failure contributors and failed motor components are related to motor overheating. Thermal stress can potentially cause the failure of all the major motor parts: Stator, Rotor, Bearings, Shaft and Frame.

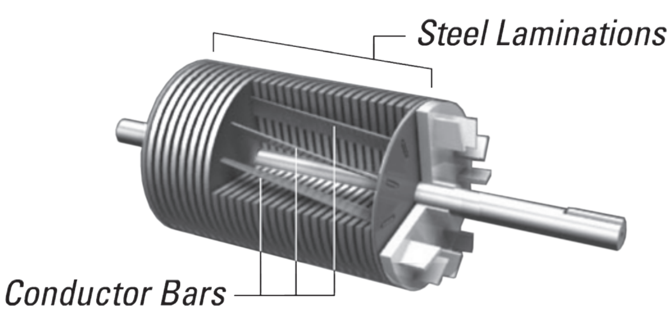


Figure 3.
Squirrel Cage Motor

2. Motor Protection Overview

There are two main risks for an overheated motor: Stator windings insulation degradation and rotor conductors deforming or melting. Insulation lifetime decreases by half if the motor operating temperature exceeds its thermal limit by 10°C. There are a number of conditions that can result in damage to three-phase motors. These damages are a result of operating conditions or internal or external faults. External faults and operating conditions include: undervoltage, asymmetrical loading, phase and ground faults on the motor feeder and overloading during starting and running operation. Internal faults include: ground faults, faults between windings and inter-turn faults.

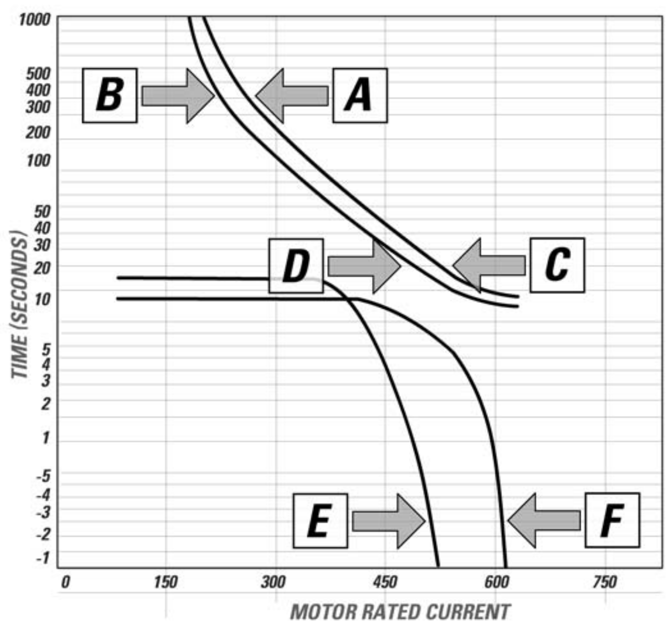
Fault Type	Protection Philosophy
Internal Fault	
Stator ground faults	Ground/Neutral IOC/TOC (50/51G/N), Neutral Directional TOC (67N)
Stator phase faults	Phase differential protection (87), Phase IOC/TOC (50/51P), Phase short circuit (50 P)
External Fault	
Overheating	Overload - Thermal model with Programmable Curves and biased with RTD and/or Unbalance (49/51) Voltage Dependant Curve for Large Inertia Loads Overtemperature via thermistors and/or RTDs (38,49) Locked rotor / mechanical jam, Stall Protection (39, 51R) Jogging, Starts/hour, time between starts, restart time delay (66), Acceleration Time Logic Reduced voltage start (19) Incomplete sequence (48) Overload lock-out (86)
Phase unbalance	Overload - Thermal model with Programmable
Phase reversal	Negative Sequence Overvoltage (47)
Abnormal voltage	Overvoltage (57), Undervoltage (27)
Abnormal frequency	Overfrequency (81O), Underfrequency (81U), Speed switch (14)
Loss of load	Undercurrent/minimum load (37), Underpower, Sensitive Directional Power (32)
Back-Spin	Back-Spin Detection
Breaker failure	Breaker failure (50BF)
Power factor	Power factor (55)
Feeder Ground Fault	Ground/Neutral IOC/TOC (50/51G/N) Neutral Directional TOC (67N)
Feeder Phase Fault	Phase differential protection (87), Phase IOC/TOC (50/51P), Phase short circuit (50 P)

Table 1.
Motor Faults

3. Overload Protection

Three-phase motors are designed in such a way that overloads must be kept below the machine thermal damage limit. The motor thermal limits curves consist of three distinct segments, which are based on the three running conditions of the motor: the locked rotor or stall condition, motor acceleration and motor running overload. Ideally, curves should be provided for both hot and cold motor conditions. For most motors, the motor thermal limits are formed into one smooth homogeneous curve.

The acceleration curves are an indication of the amount of current and associated time for the motor to accelerate from a stop condition to a normal running condition. Usually, for large motors, there are two acceleration curves: the first is the acceleration curve at rated stator voltage while the second is the acceleration at 80% of rated stator voltage (soft starters are commonly used to reduce the amount of inrush current during starting). Starting the motor on a weak system can result in voltage depression, providing the same effect as a soft-start.



A. Cold Running Overload
B. Hot Running Overload
C. Cold Locked Rotor Curve
D. Hot Locked Rotor Curve
E. Acceleration curve @ 80% rated voltage
F. Acceleration curve @ 100% voltage

Figure 4.
Motor Thermal Limits Curves

The primary protective element of the motor protection relay is the thermal overload element and this is accomplished through motor thermal image modeling. This model must account for all thermal processes in the motor while the motor is starting, running at normal load, running overloaded and if the motor is stopped. The algorithm of the thermal model integrates both stator and rotor heating into a single model. If the motor starting current begins to infringe on the thermal damage curves or if the motor is called upon to drive a high inertia load such that the acceleration time exceeds the safe stall time, custom or voltage dependent overload curves may be required. Negative sequence currents (or unbalanced phase currents) will cause additional rotor heating that will not be accounted for by electromechanical relays and may not be accounted for in some electronic protective relays. The main causes of current unbalance are: blown fuses, loose connections, stator turn-to-turn faults, system voltage distortion and unbalance, as well as external faults.

Thermal models can have following enhancements and additions: motor start inhibit; standard, custom and voltage dependant overload curves;

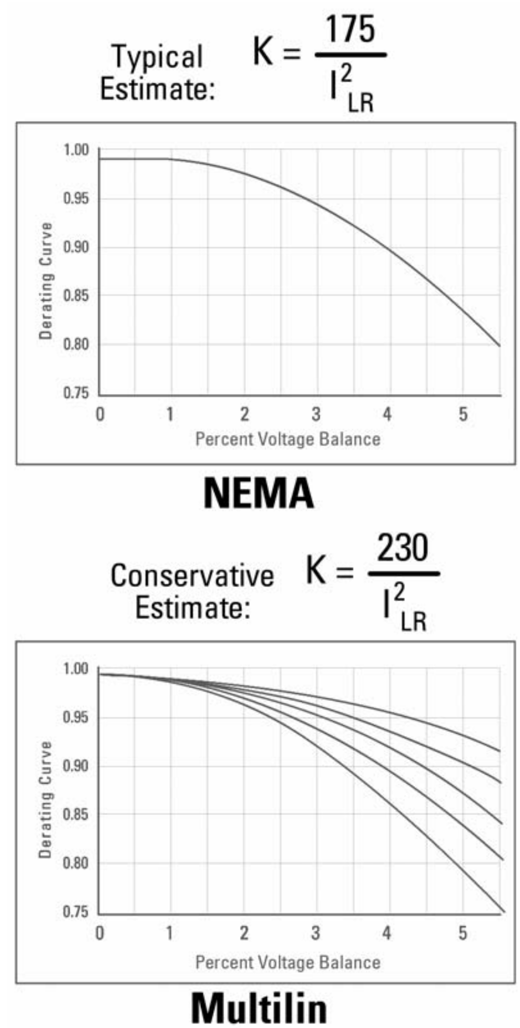


Figure 5.
Motor Derating Curves

thermal model biasing by measured current unbalance and RTD's; separate thermal time constants for running and stopped motor conditions; independent current unbalance detector; acceleration limit timer; mechanical jam detector; start and restart supervision.

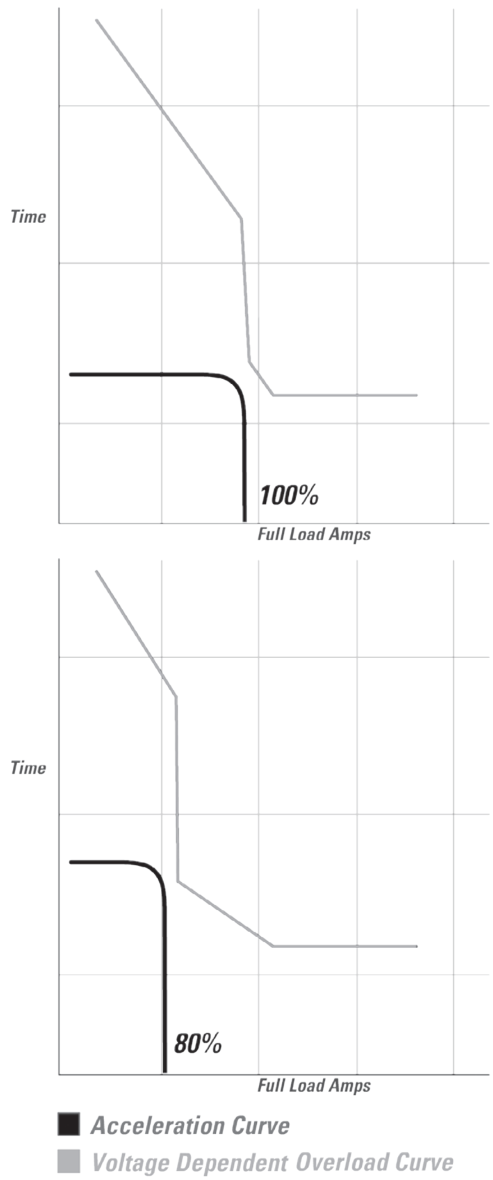


Figure 6.
Voltage Dependent Overload Curves

4. Differential Protection

This protection function is mostly used to protect induction and synchronous motors against phase-to-phase faults. This function requires two sets of CT's, one at the beginning of the motor feeder, and the other at the start point. Differential protection may be considered the first line of protection for internal phase to phase or phase to ground faults. In the event of such faults, the quick response of the differential element may limit the damage that may have otherwise occurred to the motor.

Figure 7.
RTD connection for Thermal Protection and Biasing.

The differential protection function can only be used if both sides of each stator phase are brought out of the motor for external connection such that the phase current going into and out of each phase can be measured. The differential element subtracts the current coming out of each phase from the current going into each phase and compares the result or difference with the differential pickup level. If this difference is equal to or greater then the pickup level a trip will occur. GE Multilin motor protective relays support both three and six CT configurations. For three CT configuration both sides of each of the motors stator phases are being passed through a single CT. This is known as the core balance method and is the most desirable owing to it's sensitivity and noise immunity.

If six CTs are used in a summing configuration, during motor starting, the values from the two CTs on each phase may not be equal as the CTs are not perfectly identical and asymmetrical currents may cause the CTs on each phase to have different outputs. To prevent nuisance tripping in this configuration, the differential level may have to be set less sensitive, or the differential time delay may have to be extended to ride through the problem period during motor starting. The running differential delay can then be fine tuned to an application such that it responds very fast and is sensitive to low differential current levels.

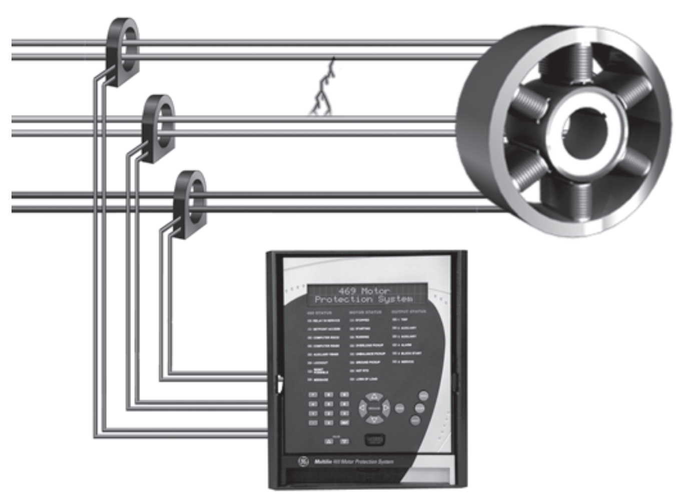


Figure 8.
Phase to Phase Fault

The Biased Differential protection method allows for different ratios for system/line and neutral CT's. This method has a dual slope characteristic to prevent a maloperation caused by unbalances between CTs during external faults. CT unbalances arise as a result of CT accuracy errors or CT saturation.

5. Ground Fault Protection

Damage to a phase conductor's insulation and internal shorts due to moisture within the motor are common causes of ground faults. A strategy that is typically used to limit the level of the ground fault current is to connect an impedance between the neutral point of the motor and ground. This impedance can be in the form of a resistor or grounding transformer sized to ensure that the maximum ground fault current is limited to a level that will reduce the chances of damage to the motor.

There are several ways by which a ground fault can be detected. The most desirable method is to use the zero sequence CT approach, which is considered the best method of ground fault detection methods due to its sensitivity and inherent noise immunity. All phase conductors are passed through the window of a single CT referred to as a zero sequence CT. Under normal circumstances, the three phase currents will sum to zero resulting in an output of zero from the zero sequence CT's secondary. If one of the motor's phases were shorted to ground, the sum of the phase currents would no longer equal zero causing a current to flow in the secondary of the zero sequence CT. This current would be detected by the motor relay as a ground fault.

If the cables are too large to fit through the zero sequence CT's window or the trench is too narrow to fit the zero sequence CT, the residual ground fault configuration can be used. This configuration is inherently less sensitive than that of the zero sequence configuration, owing to the fact that the CTs are not perfectly matched. During the motor start, the motor's phase

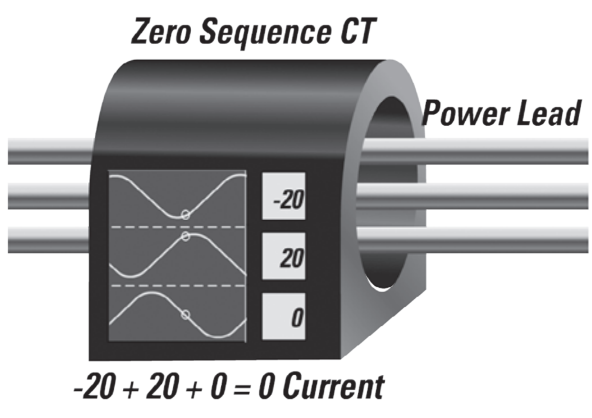


Figure 9.
Ground Fault CT Configuration

currents typically rise to magnitudes greater than 6 times the motors full load current. The slight mismatch of the CTs combined with the relatively large phase current magnitudes produce a false residual current, which will be seen by the relay. This current can be misinterpreted by the motor relay as a ground fault unless the ground fault element's pickup is set high enough to disregard this error.

6. Unbalance Protection

Unbalanced load in the case of AC motors is mainly the result of an unbalance of the power supply voltages. The negative-sequence reactance of the three-phase motor is 5 to 7 times smaller than positive-sequence reactance, and even a small unbalance in the power supply will cause high negative sequence currents. For example for an induction motor with a starting current six times the full load current, a negative sequence voltage component of 1% corresponds to a negative sequence current component of 6%. The negative-sequence current induces a field in the rotor, which rotates in the opposite direction to the mechanical direction and causes additional temperature rise. Main causes of current unbalance are: system voltage distortion and unbalance, stator turn-to-turn faults, blown fuses, loose connections, and other internal motor faults.

7. Short Circuit

The short circuit element provides protection for excessively high overcurrent faults. When a motor starts, the starting current (which is typically 6 times the Full Load Current) has asymmetrical components. These asymmetrical currents may cause one phase to see as much as 1.7 times the RMS starting current. As a result the pickup of the short circuit element must be set higher than the maximum asymmetrical starting currents seen by the phase CTs to avoid nuisance tripping. The breaker or contactor that the relay is to control under such conditions must have an interrupting capacity equal to or greater then the maximum available fault current.

8. Undervoltage

If an induction motor operating at full load is subjected to an under voltage condition, full load speed and efficiency will decrease and the power factor, full load current and

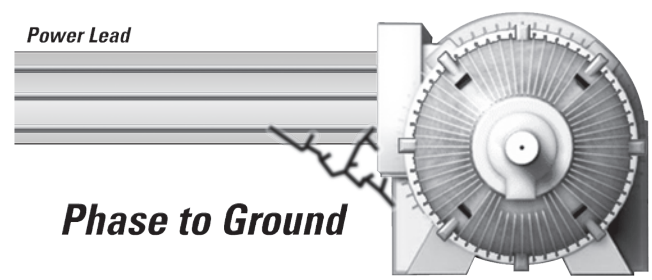


Figure 10.
Phase to Ground Fault

temperature will increase. The undervoltage element can be considered as backup protection for the thermal overload element. If the voltage decreases, the current will increase, causing an overload trip. In some cases, if an undervoltage condition exists it may be desirable to trip the motor faster than the overload element.

The overall result of an undervoltage condition is an increase in current and motor heating and a reduction in overall motor performance.

9. Overvoltage

When the motor is running in an overvoltage condition, slip will decrease as it is inversely proportional to the square of the voltage and efficiency will increase slightly. The power factor will decrease because the current being drawn by the motor will decrease and temperature rise will decrease because the current has decreased (based on I^2t). As most new motors are designed close to the saturation point, increasing the V/HZ ratio could cause saturation of air gap flux causing heating.

In this case the overall result of an overvoltage condition is an increase in current and motor heating and a reduction in overall motor performance.

10. Mechanical Jam

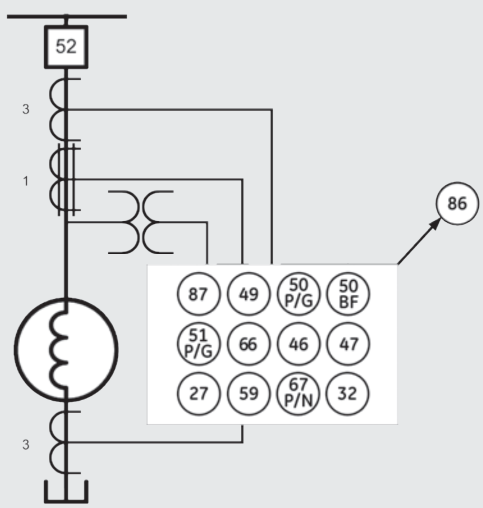
The mechanical jam element is designed to operate for running load jams due to worn motor bearings, load mechanical breakage and driven load process failure. This element is used to disconnect the motor on abnormal overload conditions before the motor stalls. In terms of relay operation, the Mechanical Jam element prevents the motor from reaching 100% of its thermal capacity while a mechanical jam is detected. It helps to avoid mechanical breakage of the driven load and reduce start inhibit waiting time.

11. Load Loss Detection

Undercurrent protection is useful for indicating the loss of suction in a pump application or a broken belt in a conveyor application. The second method of load loss detection is the use of the underpower protection element.

12. Typical Motor Protection Applications

Large motor - Two sets of CT's for differential protection

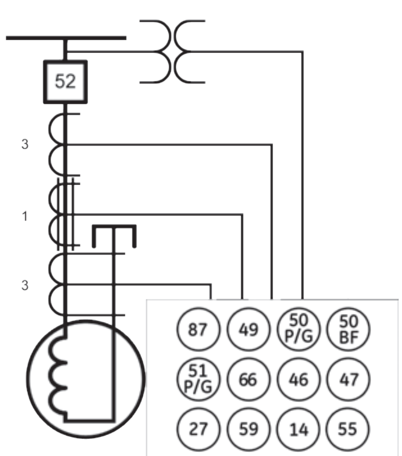


Typical Functions

87S	Stator Differential
49	Thermal Overload
49RTD	RTD Biased Thermal Overload
49S	Stator RTD
38	Bearing RTD
51R	Mechanical Jam
50P/G	Instantaneous Overcurrent
51P/G	Time Overcurrent
50BF	Breaker Failure
66	Starts per hour
46	Current Unbalance
47	Phase Reversal
27P	Undervoltage
59P/N	Overvoltage
67P/N	Directional Overcurrent
32	Directional Power
81U	Underfrequency
81O	Overfrequency

Functions		Typical Product Order Code
Typical Functions		M60-E00-HCH-F8L-H6P-M8N-P5C-UXX-WXX
Ethernet Communications	Copper	M60-N00-HCH-F8L-H6P-M8N-P5C-UXX-WXX
	Fiber	M60-G00-HCH-F8L-H6P-M8N-P5C-UXX-WXX
Lockout	Standalone	HEA61-A-RU-220-X2
	Integrated	M60-E00-HPH-F8L-H6P-M8N-P5C-U4L-WXX

Large motor - One set of CT's for differential protection

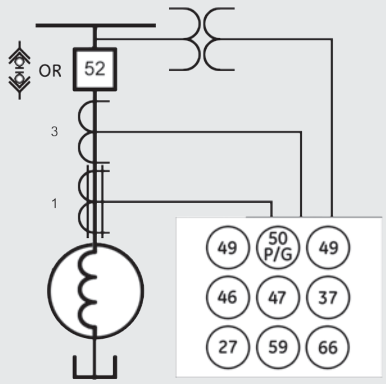


Typical Functions

87S	Stator Differential
49	Thermal Overload
49RTD	RTD Biased Thermal Overload
49S	Stator RTD
38	Bearing RTD
51R	Mechanical Jam
50P/G	Instantaneous Overcurrent
51P/G	Time Overcurrent
50BF	Breaker Failure
66	Starts per hour
46	Current Unbalance
47	Phase Reversal
27P	Undervoltage
59P/N	Overvoltage
14	Speed Switch
55	Power Factor

Functions		Typical Product Order Code
Typical Functions		469-P5-HI-A20-E
Communications	Ethernet	469-P5-HI-A20-T
	DeviceNet	469-P5-HI-A20-D
Lockout	Standalone	HEA61-A-RU-220-X2
	Integrated	M60-E00-HPH-F8L-H6P-M8N-P5C-U4L-WXX

Large or medium size motor

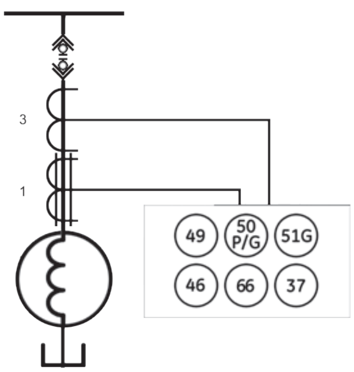


Typical Functions

49	Thermal Overload	66	Starts per hour
49RTD	RTD Biased Thermal Overload	46	Current Unbalance
49S	Stator RTD	47	Phase Reversal
38	Bearing RTD	27P	Undervoltage
51R	Mechanical Jam	59P/N	Overvoltage
50P/G	Instantaneous Overcurrent	37	Undercurrent
51G	Time Overcurrent		

Functions		Typical Product Order Code
Typical Functions		M60-E00-HCH-F8L-H6P-M5C-U5D-WXX 469-P5-HI-A20-E 369-HI-R-M-0-0-0
Communications	Ethernet	M60-N00-HCH-F8L-H6P-M5C-U5D-WXX 469-P5-HI-A20-T 369-HI-R-M-0-E-0
	DeviceNet	469-P5-HI-A20-D 369-HI-R-M-0-D-0
	Profibus	369-HI-R-M-0-P-0
Lockout	Standalone	HEA61-A-RU-220-X2
	Integrated	M60-E00-HPH-F8L-H6P-M8N-P5C-U4L-WXX
Harsh Environment		469-P5-HI-A20-E-H 369-HI-R-M-0-0-H

Medium size motor

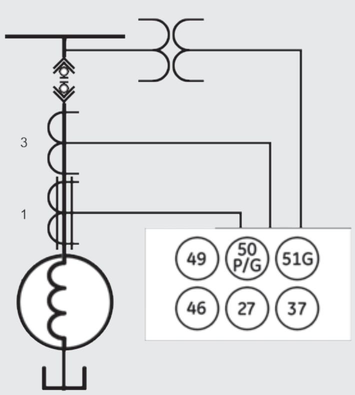


Typical Functions

49	Thermal Overload	**46**	Current Unbalance
49RTD	RTD Biased Thermal Overload	**66**	Starts per hour
49S	Stator RTD	**37**	Undercurrent
38	Bearing RTD		
51R	Mechanical Jam		
50P/G	Instantaneous Overcurrent		
51G	Time Overcurrent		

Functions		Typical Product Order Code
Typical Functions		369-HI-R-M-0-0-0 269Plus-SV-1-1-100P-HI 239-RTD-AN
Communications	**Ethernet**	369-HI-R-M-0-E-0
	DeviceNet	369-HI-R-M-0-D-0
	Profibus	369-HI-R-M-0-P-0
Lockout	**Standalone**	HEA61-A-RU-220-X2
Harsh Environment		369-HI-R-M-0-0-H 239-RTD-AN-H

Small size, low voltage motor



Typical Functions

49	Thermal Overload	46	Current Unbalance
49RTD	RTD Biased Thermal Overload	27P	Phase Undervoltage
49S	Stator RTD	37	Undercurrent
38	Bearing RTD		
51R	Mechanical Jam		
50P/G	Instantaneous Overcurrent		

Functions		Typical Product Order Code
Typical Functions		MM300-B-E-H-S-S-C-A-G 239-RTD-AN MM2-PD-2-120
Lockout	**Standalone**	HEA61-A-RU-220-X2
Harsh Environment		239-RTD-AN-H

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Setting a Motor Management Relay for a Cyclic Load Application

1. Introduction

A motor's service life depends on many variables surrounding its application. When several starts and stops (duty cycle) are demanded, heat generated in the windings subject the motor to time dependant thermal stress. Applications in which overloads occur in a cyclic manner also thermally stress the motor over time. The protection relay thermal model is then taken to determine the acceptable level of running time so that the thermal limits of the motor or actuator components are not exceeded. We will now focus on applying the necessary settings to a motor management relay. For this example, the GE Multilin 469 relay was used.

The 469 relay provides thermal motor protection based on an approach similar to a single time constant thermal model. This document analyzes the behavior of the 469 and compares it with a single time constant thermal model under a variety of load dynamic conditions. It is shown that the behavior of the 469 is approximately the same as that of a thermal model under any loading condition, provided the implicit time constant of the overload curve is matched to the explicit cooling time constant. In particular, it is shown that when the time constants are properly matched, the relay works correctly on cyclic loads. This application note also provides practical examples of how to set up the 469 for cyclic load applications using either standard overload curves or custom overload curves.

2. Single Time Constant Thermal Model

First, we will compare the 469 with a simple, single time constant thermal model under constant load.

A simple thermal model is sometimes used to approximate the thermal behavior of a motor as an aid in understanding motor thermal protection. The model often has the following features:

- Heating arises from I^2R losses in the motor. During steady state loading, the temperature of the motor reaches its maximum capability (rated temperature rise) when the motor is drawing rated current.
- During transient conditions, two thermal processes are considered: heat storage in the motor, and heat transfer from the motor to the ambient.
- Heat storage in the motor is proportional to the heat capacity of the motor times the time rate of change of the motor temperature.
- Heat transfer from the motor out to the ambient is proportional to the motor temperature rise above the ambient.
- When the motor thermal model temperature exceeds the maximum allowable value, thermal protection is provided by shutting the motor off.

The transient behavior of the model can be summarized by the following equation:

$$C \cdot \frac{dT'}{dt} = I'^2(t) \cdot R - H \cdot T'(t) \qquad \text{(Eq 1)}$$

where:

T'(t) = motor temperature rise above ambient

I'(t) = motor current

C = specific heat capacity of the motor

H = running heat dissipation factor

R = electrical resistance.

The left side of Equation 1 represents heat storage in the motor. The first term on the right side of the equation represents heat generated in the motor due to I2R losses. The second term on the right represents heat transfer from the motor to the ambient.

It is convenient to rewrite Equation 1 in terms of per unit temperature rise and per-unit current by expressing the current as a fraction of rated current and the temperature as a fraction of the thermal limit temperature. In this case, we use:

$$\begin{aligned} T(t) &= \frac{T'(t)}{T_{max}} = \text{per-unit temperature rise} \\ I(t) &= \frac{I'(t)}{I_{rated}} = \text{per-unit current} \\ I_{rated} &= \text{rated current} \\ T_{max} &= \text{motor temperature at thermal limit trip condition} \end{aligned} \qquad \text{(Eq 2)}$$

In this case, Equation 1 can be rewritten as:

$$\tau \cdot \frac{dT(t)}{dt} = I^2(t) - T(t), \text{ where } \tau = \frac{C}{H} \qquad \text{(Eq 3)}$$

Equation 3 can be used to analyze the thermal response of an overloaded motor. It can be shown that the temperature rise above ambient for the solution of Equation 3 for a steady overload from a cold start is given by:

$$T(t) = I^2 \cdot (1 - e^{-t/\tau}) \qquad \text{(Eq 4)}$$

where:

I = per-unit motor current (a constant)

T(t) = per-unit motor temperature rise.

Next, Equation 4 can be solved for the time required for the temperature rise to reach the thermal limit of the motor i.e., T(t) = 1:

$$t_{max}(I) = \tau \cdot \ln\left(\frac{I^2}{I^2 - 1}\right) \quad \text{(Eq 5)}$$

where $t_{max}(I)$ is the time estimated by a simple thermal model for the motor temperature to reach the thermal limit.

3. Overload Curves

To develop a comparison between a simple thermal model and the 469, we now turn our attention to overload curves, which the 469 uses to determine how long a motor can safely withstand motor overload at a specific value of motor current. The standard overload curves are given by:

$$t_{max}(I) = \frac{87.4 \cdot CM}{I^2 - 1} \quad \text{(Eq 6)}$$

where:

$t_{max}(I)$ is the trip, in second

CM is the curve multiplier

To compare the overload curves with the behavior of a simple thermal model, it is useful to start by recognizing that the numerator of the right hand side of Equation 6 corresponds to the time constant of the thermal model:

$$t_{max}(I) = \frac{\tau_{CM}}{I^2 - 1} \quad \text{(Eq 7)}$$

where:

$\tau_{CM} = 87.4 \times CM$

Equations 5 and 7 are plotted in Figure 1. To ensure the curves align for large values of current, it is necessary to satisfy the following constraint:

$$\tau = \frac{C}{H} = \tau_{CM} = 87.4 \cdot CM \quad \text{(Eq 8)}$$

In other words, in order for an overload curve to match a simple thermal model during a step overload, the time constant implied by the curve multiplier must be set equal to the time constant of the thermal model.

In the following figure, the ratio of the time divided by the time constant is plotted against per unit current. Although Equation 7 is not exactly the same as Equation 5, the approximation is very close, particularly for large values of current. For values of current overload closer to the motor rating, the standard overload curves produce longer times than those of the simple

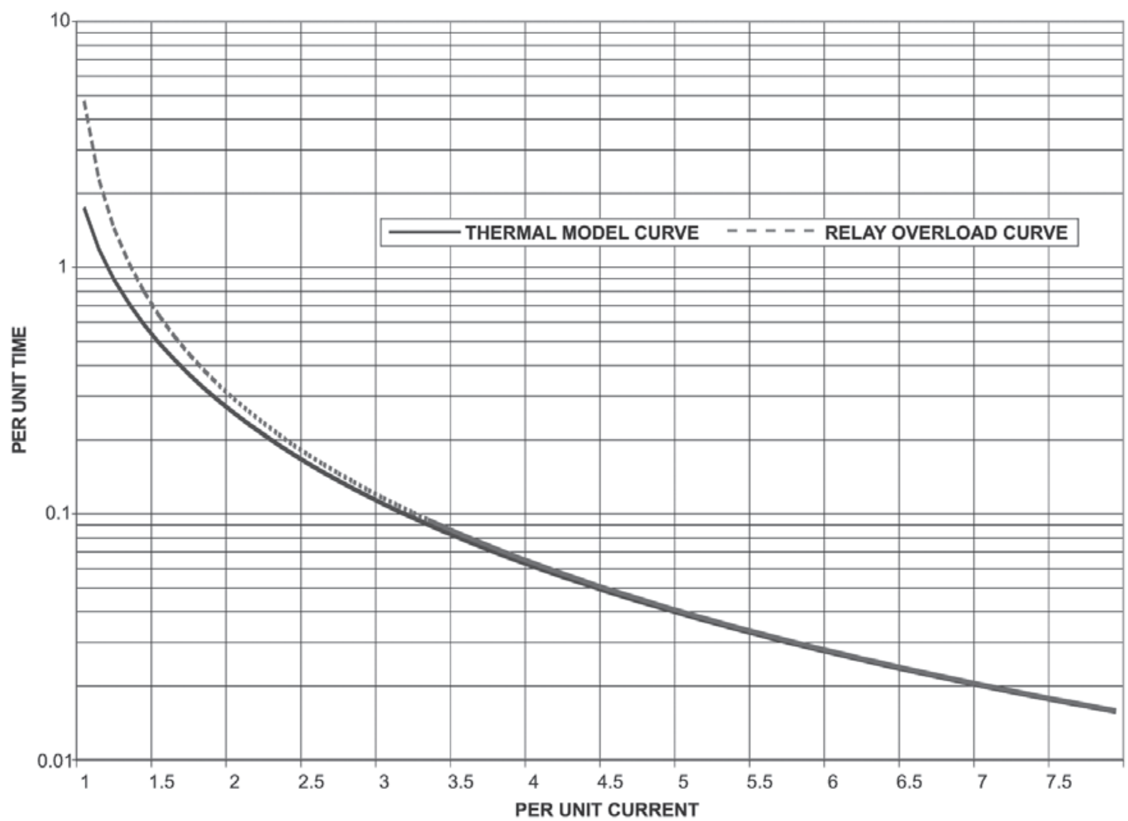

Figure 1.
Thermal Model versus Relay Overload Curves Comparison

thermal model. However, in that region it is the value of the current rather than the value of the time that is important, because the temperature of the motor is changing slowly. In any case, neither curve exactly matches the actual thermal behavior of a motor, which is described by a multiple time constant thermal model. Either curve can approximate the manufacturer's published curve by adjusting parameters to shift the curve vertically or horizontally.

Equation 6 describes the time for the 469 to reach thermal limit for a constant overload. We now turn our attention to how the 469 behaves during transient overload conditions in general, by starting with the differential equation that is used within the 469 to implement standard overload curves:

$$\frac{dT(t)}{dt} = \frac{I^2(t) - 1}{\tau_{CM}} \qquad \text{(Eq 9)}$$

Equation 9 can be rearranged as follows:

$$\tau_{CM} \cdot \frac{dT(t)}{dt} = I^2(t) - 1 \qquad \text{(Eq 10)}$$

From Equation 3, recall that the simple thermal model is described by:

$$\tau \cdot \frac{dT(t)}{dt} = I^2(t) - T(t) \qquad \text{(Eq 3)}$$

For large values of overload, such as would be encountered during stalled operation of a motor, the temperature changes in a time frame that is much shorter than the time constant of the motor. In that case the first term on the left sides of Equations 10 and 3 dominates, so that both Equations are approximated by:

$$\tau_{CM} \cdot \frac{dT(t)}{dt} = \tau \cdot \frac{dT(t)}{dt} \approx I^2(t), \quad I^2(t) >> 1 \qquad \text{(Eq 11)}$$

In other words, for large values of current, the standard overload curves and a simple thermal model will behave almost identically, provided the overload curve multiplier is set according to Equation 8.

For values of overload current close to rated, the relay overload curves take somewhat longer to trip than the a simple thermal model with the same constant, because of the difference between the second terms in Equations 3 and 10.

4. Simple Cycling Load Analysis

So far, the analysis has considered situations in which the current exceeds the motor rating. To gain insights into what happens when the current also drops below full load, we now turn our attention to a simple cycling load in which the current alternates between zero and an overload value:

$$\begin{aligned} I_{low} &= 0 \approx \text{motor current during the low cycle} \\ I_{high} &= \text{motor current during the high cycle} \\ t_{low} &= \text{time interval for the low cycle} \\ t_{high} &= \text{time interval for the high cycle} \end{aligned} \qquad \text{(Eq 12)}$$

The motor heating is proportional to the square of the current, so the effective current for heating over the cycle is:

$$H_{effective} = I^2_{effective} = \frac{t_{high} \cdot I^2_{high} + t_{low} \cdot I^2_{low}}{t_{low} + t_{high}} \qquad \text{(Eq 13)}$$

where:

$I_{effective}$ = effective value of the load current

$H_{effective}$ = effective heating value of the load

Equation 13 can also be expressed in terms of a duty cycle ratio:

$$H_{effective} = D \cdot I^2_{high} + (1 - D) \cdot I^2_{low} \qquad \text{(Eq 14)}$$

where: $D = \text{duty cycle ratio} = \dfrac{t_{high}}{t_{low} + t_{high}}$

If the current and heating are expressed in per-unit values and low cycle current is approximately equal to zero, the steady state boundary condition for tripping the motor becomes:

$$1 = D \cdot I^2_{high} \qquad \text{(Eq 15)}$$

Analysis of the 469 under load cycling conditions will reveal how to set it properly to match the behavior specified by Equation 15. We start by extending the previous analysis to values of current below pickup, during which the 469 motor thermal model is defined by the following differential equation that describes thermal cooling when motor loading is below pickup:

$$\frac{dT(t)}{dt} = \frac{1}{\tau_{cool}} \cdot \left(I \cdot \left(1 - \frac{\text{hot}}{\text{cold}} \right) - T(t) \right) \qquad \text{(Eq 16)}$$

where:

τ_{cool} = cooling time constant

hot = hot stall time

cold = cold stall time

The (1 - hot/cold) factor is included to match the hot and cold stall times specified by the motor manufacturer. By including the factor in the cooling computation, the hot overload curve is effectively shifted down by the correct amount relative to the cold overload curve to account for the difference in 'time to trip' of hot and cold motor conditions.

For the load cycle under consideration, the current during the unloaded part of the cycle is approximately equal to zero, so the differential equation given by 16 reduces to:

$$\frac{dT(t)}{dt} = -\frac{T(t)}{\tau_{cool}} \qquad \text{(Eq 17)}$$

Taken together, Equations 17 and 10 describe the behavior of the 469 during the assumed load cycle. During the overload portion of the cycle, the temperature computed according to Equation 10 rises. During the unloaded portion of the cycle, the temperature computed according to Equation 17 falls. For a heavy-duty cycle situation, the temperature increase during overload is greater than the temperature decrease during zero load. The temperature gradually ratchets upward until it reaches the maximum allowable value and the 469 shuts off the motor.

Whether or not the temperature reaches a tripping condition depends on the severity of the duty cycle. For a severe overload, the temperature ratchets up past the maximum value. For a load just below the threshold of tripping, the temperature reaches a steady state cycle just below the maximum value, and the 469 allows the motor to continue to operate. The approximate boundary between overload and normal operation can be determined by analyzing the steady state limit cycle, as the temperature approaches 1 per unit.

The approximate temperature rise during the overload portion of the load cycle estimated by the overload curve is computed by multiplying Equation 10 by the overload time:

$$\Delta T_{high} \approx \frac{1}{\tau_{CM}} \cdot (I_{high}^2 - 1) \cdot t_{high} \qquad \text{(Eq 18)}$$

The approximate temperature drop estimated by the cooling model during the unloaded portion of the duty cycle is computed by multiplying Equation 17 by the appropriate time, with per unit temperature equal to 1, because that is what it will be approximately equal to during a limit cycle that approaches tripping:

$$\Delta T_{low} \approx -\frac{1}{\tau_{cool}} \cdot t_{low} \qquad \text{(Eq 19)}$$

The overload detection boundary is determined by setting the net temperature change equal to zero. This implies that the total of the right hand sides of Equations 18 and 19 is equal to zero:

$$\Delta T_{high} + \Delta T_{low} = \frac{1}{\tau_{CM}} \cdot (I_{high}^2 - 1) \cdot t_{high} - \frac{1}{\tau_{cool}} \cdot t_{low} = 0 \qquad \text{(Eq 20)}$$

Equation 20 can be rearranged to highlight how to properly set the 469 for load cycling applications:

$$1 = \frac{\tau_{cool}}{\tau_{CM}} \cdot D \cdot I_{high}^2 \qquad \text{(Eq 21)}$$

Equation 21 expresses the actual overload detection boundary of the 469 in terms of its settings, the duty cycle, and the amount of overload. Except for the factor of τcool / τCM, Equation 21 is the same as ideal overload detection boundary, specified by Equation 15. Equations 21 and 15 will be identical, provided that τcool / τCM is set equal to one. This makes sense from a physical point of view. The cooling time constant as well as the overload curve time constant arise from the same physical parameters, so they should come out to be the same. In other words, in order for the 469 to provide appropriate thermal protection during load cycling applications, it is necessary to satisfy the following constraint.

$$\tau_{cool}(\text{min}) = \frac{87.4 \cdot \text{CM}}{60} \qquad \text{(Eq 22)}$$

Equation 22 represents a consistency constraint relating the cooling time constant and the overload curve. For most applications, it is not necessary to satisfy the constraint. However, in the case of a load that cycles above and below pickup, Equation 22 should be approximately satisfied. Otherwise, the computed motor temperature will tend to ratchet up or down. The following figure illustrates what can happen. There are three cases shown for a cycling load with an approximate per unit heating value of one. In the first case, the cooling time constant is set too long resulting in over-protection and early

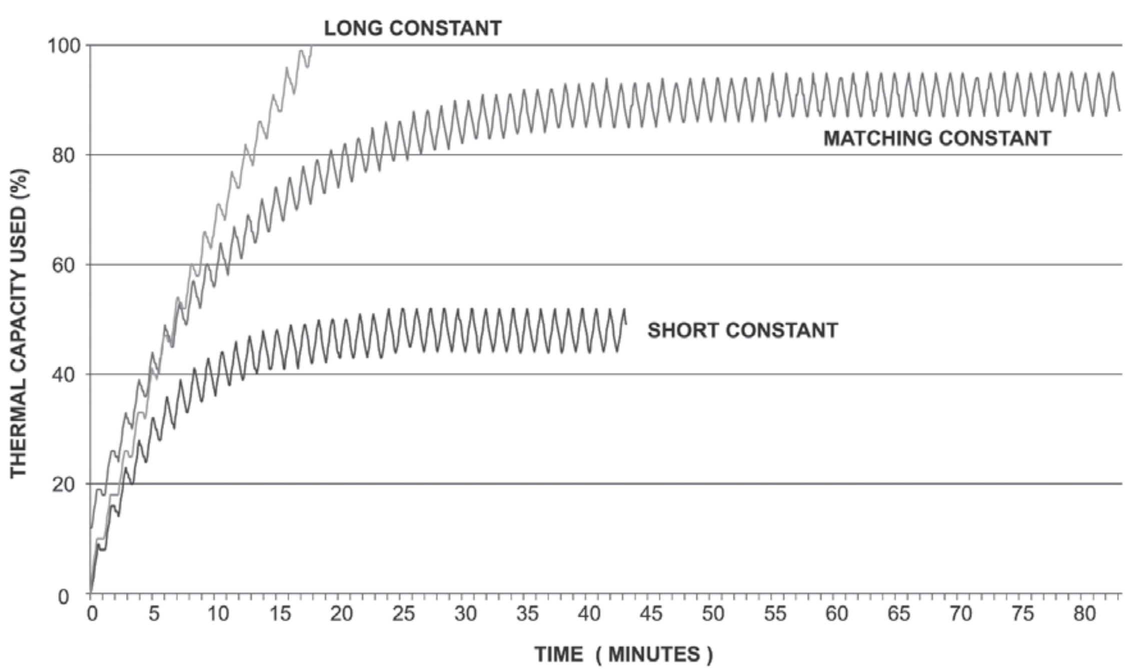

Figure 2.
Relay Response to Cyclic Loading Application, (the constraint specified by Equation (22) should be satisfied)

motor tripping. In the second case, the cooling time constant is set to match the implied time constant of curve multiplier, and the protection is correct. In the third case, the cooling time constant is set too short, resulting in under-protection and possible motor overheating.

When setting the 469 for a cyclic loading application, the constraint specified by Equation 22 should be satisfied.

5. Custom Overload Curves

For custom overload curves, the cooling and overload time constants can be matched using a graphical procedure. The goal is to match the explicit cooling time constant to the time constant that is implied by the overload curve in the vicinity of rated current. The key to achieving the match is Equation 7, repeated here for convenience:

$$t_{max}(I) = \frac{\tau_{CM}}{I^2 - 1} \quad \text{(Eq 7)}$$

Equation 7 applies to standard overload curves. It is simple enough to extend it to custom curves by allowing the implied time constant to be a function of current:

$$t_{max}(I) = \frac{\tau_{CM}(I)}{I^2 - 1} \quad \text{(Eq 23)}$$

The implied time constant can then be computed as a function of current from the overload curve as follows:

$$\tau_{CM}(I) = (I^2 - 1) \cdot t_{max}(I) \quad \text{(Eq 24)}$$

According to Equation 24, the implicit time constant is a function of the motor load. For the purposes of the cooling portion of the thermal model, a single number is needed. The most appropriate number to use is one that will result in well-behaved response to a duty cycle. In that case, we are interested in the values produced by Equation 24 as the load current approaches full rated. This suggests a graphical technique for determining the appropriate cooling time constant: Plot the quantity given by Equation 24 as a function of per unit load current, using the custom overload curve to determine. The appropriate time constant is the value of the curve as the current approaches the maximum overload value during the load cycle.

The following example is given to clarify the procedure. Let us consider an example of cyclic load application with maximum overload current excursions of 1.5 of motor rating. For this particular example, suppose that the motor thermal limit is represented in the 469 relay by the custom overload curve in Figure 3 on the following page.

The appropriate value of the time constant can be derived by defining the maximum time value (tmax) matching 1.5 per unit current from Figure 3 on page 9. The time constant is computed from Equation 24:

$$\tau_{CM}(I) = \frac{(1.5^2 - 1) \cdot 420 \text{ sec}}{60} = 8.7 \approx 9 \text{ minutes} \quad \text{(Eq 25)}$$

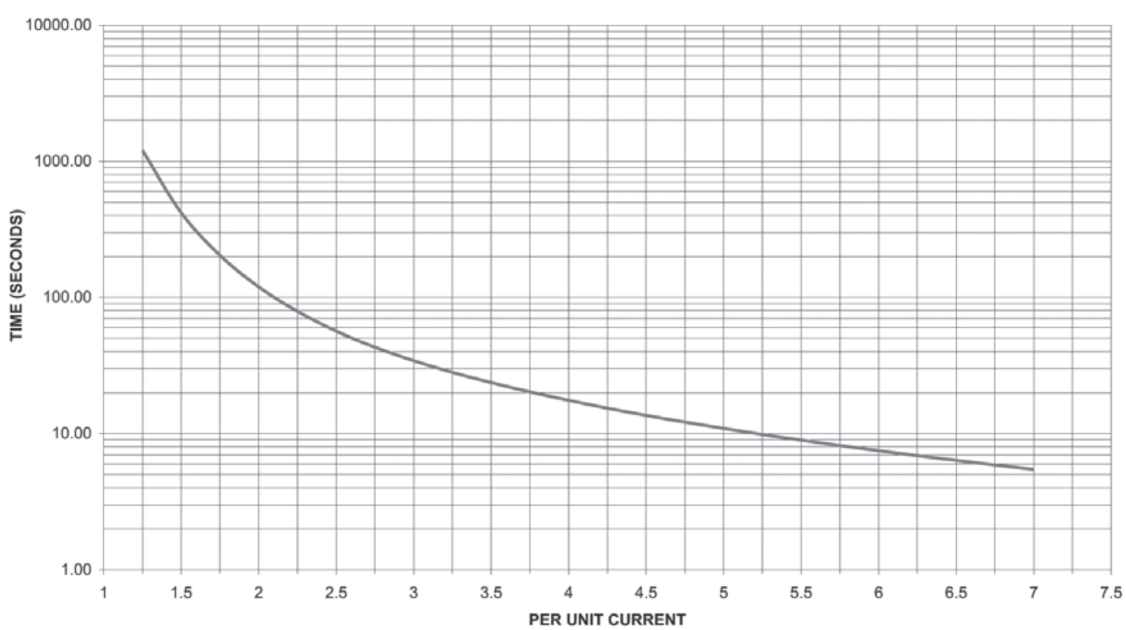

Figure 3.
Example of a Custom Overload Curve

6. Cooling Constants Calculation Example

This practical example provides the guidelines of how to calculate the matching COOLING TIME CONSTANT setpoint for Standard and Custom overload curves.

Consider motor load cycles every 30 seconds between 20% and 140% of the rated current.

The best match to the motor thermal limit curves provided by motor manufacturer is relay standard overload curve # 4.

First of all we should ensure that the cyclic load is within the steady state boundary condition for tripping the motor and per unit effective heating is not higher than 1. Per Equation 14, the per unit effective heating is calculated as:

$$D = \text{duty cycle ratio} = \frac{t_{high}}{t_{low} + t_{high}} = \frac{30\ \text{sec}}{30\ \text{sec} + 30\ \text{sec}} = 0.5 \quad \text{(Eq 26)}$$

$$H_{effective} = 1.4^2 \cdot 0.5 + 0.2^2 \cdot 0.5 = 1$$

Now we see that the presented cyclic load satisfies the condition for constants matching. Per Equation (22), the cooling constant setpoint is calculated as:

$$\tau_{cool} = \frac{87.4 \cdot CM}{60} = \frac{87.4 \cdot 4}{60} = 5.8 \approx 6\ \text{min.} \quad \text{(Eq 27)}$$

The thermal capacity graph matching constant for Figure 2 presents 469 relay behavior under described load conditions and programmed per calculated setpoints. If in cyclic load applications hot/cold ratio setpoint is set lower than 0.8, then the running cooling constant should be set proportionally lower than calculated in Equation (22) to achieve the adequate relay response.

For example if the hot/cold ratio setpoint is 0.7, then the cooling constant setpoint is calculated as follows:

$$\tau_{cool} = \frac{87.4 \cdot CM}{60} \cdot \frac{0.7}{0.8} = \frac{87.4 \cdot 4}{60} \cdot \frac{0.7}{0.8} = 5.1 \approx 5\ \text{min.}$$

7. Summary

The thermal algorithm in the 469 relay approximates the behavior of a traditional single time constant thermal model under any loading condition. Relay overload curves provide an implied thermal time constant for this algorithm.

For the relay to work correctly on balanced cyclic loads, the cooling time constant must be set in conjunction with the overload curve. When the time constants are properly matched, the relay presents a realistic motor thermal image in pulsating load applications.

Upcoming Events

2007 PCIC Conference | September 16 - 19 | Calgary, Alberta, Canada

The Petroleum and Chemical Industry Committee (PCIC) of the Industry Applications Society of IEEE invites you to attend its 54th annual conference in Calgary. Under the sponsorship of the Industry Applications Society, the PCIC Conference has become the premier annual application meeting for practicing electrical engineers. The conference is noted for the high quality and practical application of its technical papers. The technical program this year will continue to feature papers focusing on the technology and issues faced by electrical engineers in the petroleum and chemical industry.
www.ieee-pcic.org

GE Multilin Papers

- Cost-efficient applications of Bus Transfer Schemes utilizing microprocessor based relaying technology
- Safety First: The detection of downed conductors and arcing on overhead distribution lines
- Challenges and solutions in medium voltage motor protection due to motor starting

Other GE Papers

- Further progress on IEC 60034-18-42: A technical specification for qualification of motor insulation for medium-voltage inverter duty applications
- Sealed Winding Conformance Testing and recent revisions to NEMA MG-1
- Zone based protection for Low Voltage Systems, zone selective interlocking, bus differential and the single processor concept
- Economical and technical aspects of the motor protection choice: a comparison between open, weather protected I and II, and totally enclosed machines
- Predicting and minimizing slow roll Run Out: measurement system for predicting slow roll performance early in manufacturing on AP 546 and 541 motors and generators

GE Hospitality Suite, Hyatt Hotel

Sunday, September 16th – 6:00 pm – 11:00 pm
Monday, September 17th – 9:00 pm to 11:00 pm
Tuesday, September 18th – 6:00 pm to 11:00 pm
Wednesday, September 19th – 5:00 pm to 10:00 pm

GE "Dessert First" Social

Monday, September 17th - 8:00 pm - 10:00 pm

ISA Expo 2007 | October 2 - 4 | Houston, Texas, United States

ISA EXPO is your source for in-depth technical coverage of critical automation and control topics including: security, safety, process automation, enterprise integration, as well as environmental and quality control. In addition, learn more about a range of technologies from SCADA (Supervisory Control and Data Acquisition), signal compatibility, wireless, cyber-security, and field-buses to industrial Ethernet, safety buses, EDDL (Electronic Device Description Language) network selection, and ISA-100 wireless standards.
www.isa.org/expotemplate.cfm

GE Multilin Tradeshow booth

- Visit GE Multilin at booth #2947 and GE MDS at booth #2535

Exhibition Hours

Tuesday, October 2nd – 1:00 pm to 8:00 pm
Wednesday, October 3rd – 10:00 am to 5:30 pm
Thursday, October 4th – 10:00 am to 3:30 pm

Upcoming Events

2007 WPRC Conference | October 16 - 18 | 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. This forum allows participants to learn and apply advanced technologies that prevent electrical power failures.
http://capps.wsu.edu/conferences/wprc/

GE Multilin Papers

- Protection and Control Redundancy Considerations in Medium Voltage Systems
- Application of Digital Radio for Distribution Pilot Protection and Other Applications
- Impact of Frequency Deviations on Protection Functions
- Fundamentals of Distance Protection
- Challenges for Inrush Restraint when Protecting Transformers Directly Connected to Transmission Lines
- Power System Frequency Measurement and Frequency Relaying

GE MDS Papers

- NERC/CIP Security Standards: What you need to know to comply

Protection Relay Fundamentals Seminar

- Monday, October 16th – 8:00 am to 4:00 pm
- Spokane Center – Registration is free and lunch is included
- For more information contact janice.morison@ge.com

GE Hospitality Suite – Red Lion Hotel – Room 5009/5010

- Nightly October 16th, 17th and 18th – 6:00 pm to 10:00 pm

2007 CIGRÉ Madrid | October 16 - 18 | Madrid, Spain

The CIGRÉ Study Committee B5 provides a unique opportunity to learn, discuss and exchange experience about the major structural, technical, managerial and regulatory changes that are now being made and will continue to occur with the increasing demand for renewable energy. CIGRÉ also aims to keep attendees up to date on the key issues in the industry through presentations, discussions, tutorials and an exhaustive industry exhibition show casing the latest technologies and developments.
www.cigremadrid2007.com

GE Multilin Tradeshow Stand

- Visit the GE Multilin Stand in the Technical Exhibition

Exhibition Hours

Tuesday, October 17th – 8:30 am to 6:00 pm
Wednesday, October 18th – 8:30 am to 6:00 pm

Indonesian Electric 2007 | Oct 31 - Nov 3 | Kemayoran, Jakarta, Indonesia

New developments in Indonesia's infrastructure sector, particularly for the power industry, has created a huge opportunity for technology and equipment providers supplying products and services from around the world. The Electric Indonesia Exhibition includes products and technology ranging from power, transmission and distribution right through to electrical contracting supplies. The show is part of the Energy & Mining Indonesia series, so you can add value to your visit by re-registering and visiting the adjoining halls to see related technology displays. There are also seminar programs covering important issues facing the industry today.
www.pamerindo.com/2007/electric/ele07exh.htm

GE Multilin Tradeshow Stand

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Upcoming Events

2007 Offshore Communications	November 6 - 8	Houston, Texas, United States

Offshore Communications 2007 Conference & Exhibition will focus on state-of-the-art technology, standards, business trends, and critical regulatory considerations. The program will feature key players in the communications services arena, including operators, manufacturers, value-added resellers, distributors and retailers. The event coincides with unprecedented developments in the provision of new broadband solutions capable of delivering Internet, voice, video and other communications services. Major operators and broadcasters either have launched or are making plans to unveil offerings tailored for oil & gas applications, as well as disaster recovery, emergency management and maritime operations.
www.offshorecoms.com

GE MDS Tradeshow Booth

- Visit GE MDS at Booth #128

2007 Energy 21C	November 11 - 14	Sydney, Australia

The Energy 21C conference addresses the current and future issues facing the electricity and gas, transmission and distribution sectors, as well as allied product and service industries. It is focused on stimulating debate and innovation, providing solutions for the changing needs of the 21st century. Energy 21C is a conference organized by industry, for industry.
www.e21c.com.au

Product Demonstration

- CSE-Uniserve will be showcasing GE Multilin products and services

The Workboat Show	November 28 - 30	New Orleans, Louisiana, United States

The International WorkBoat Show is the largest commercial marine tradeshow in North America serving people and businesses working on the coastal, inland and offshore waters. 1,000 exhibitors will display products and services for commercial vessels and the companies that build, service and operate them.
www.workboatshow.com

GE Multilin Tradeshow Booth

- Ernest N. Memorial Convention Center

GE Multilin 2007 Course Calendar

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SCHEDULED COURSES IN NORTH AMERICA

Courses for 2007	Tuition	CEU Credits	JUL	AUG	SEP	OCT	NOV	DEC
Fundamentals of Modern Protective Relaying	$2,400 USD	2.8	10-13		10-13		13-16	
Power System Communications	$1,200 USD	1.4	19-20	16-17				
Introduction to the IEC61850 Protocol	$1,800 USD	2.1			25-27			
Distribution Protection Principles & Relaying	$1,800 USD	2.1			17-19			
Motor Protection Principles & Relaying	$1,800 USD	2.1	16-18			2-4		3-5
UR Platform	$1,800 USD	2.1		13-15		15-17		
UR Advanced Applications	$3,000 USD	1				22-26		
EnerVista Software Suite Integration	$600 USD	0.7			14	5		
JungleMUX Hands-On	$950 USD				17-21 (Vancouver)			

All North American courses are located in Markham, Ontario, Canada unless otherwise stated

SCHEDULED COURSES IN EUROPE

Courses for 2007	Tuition	CEU Credits	JUL	AUG	SEP	OCT	NOV	DEC
Universal Relay Advanced Applications	$3,000 USD	3.5			24-28 (English)		12-16 (English)	
Universal Relay Platform	$1,800 USD	2.1			19-21 (English)		7-9 (English)	
Distribution Management Relays	$1,800 USD	2.1	9-11 (English)					
Fundamentals of Modern Protective Relaying	$2,400 USD	2.8						10-13 (English)
Motor Management Relays	$1,800 USD	2.1	16-18 (English)					
F650 Platform	$1,800 USD	2.1				8-10 (Spanish)		3-5 (English)
IEC 61850	$2,400 USD	1.4				11-12 (Spanish)		

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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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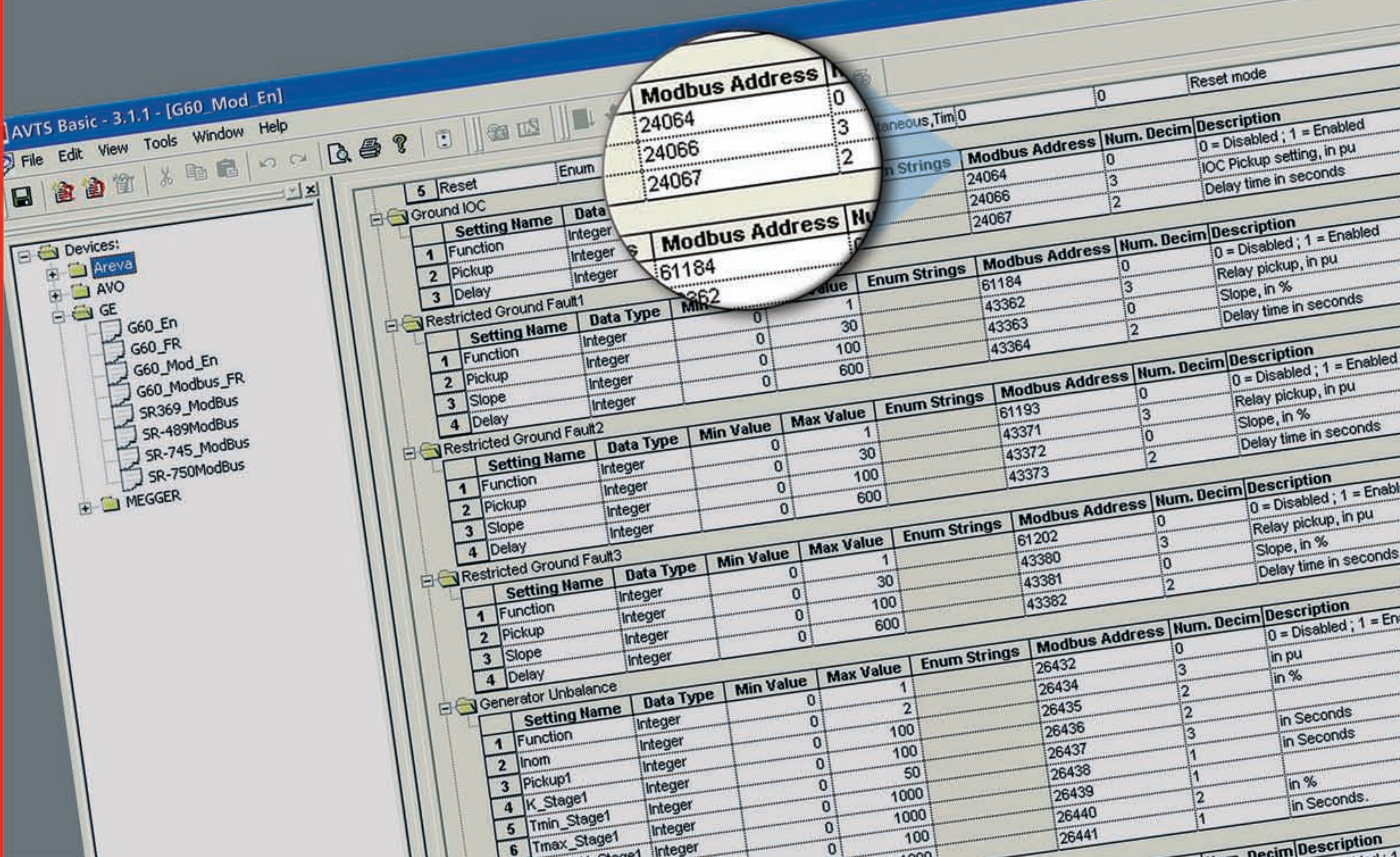

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