Grid Solutions

PROTECTION AND CONTROL REDUNDANCY CONSIDERATIONS IN MEDIUM VOLTAGE DISTRIBUTION SYSTEMS

Case Study

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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.

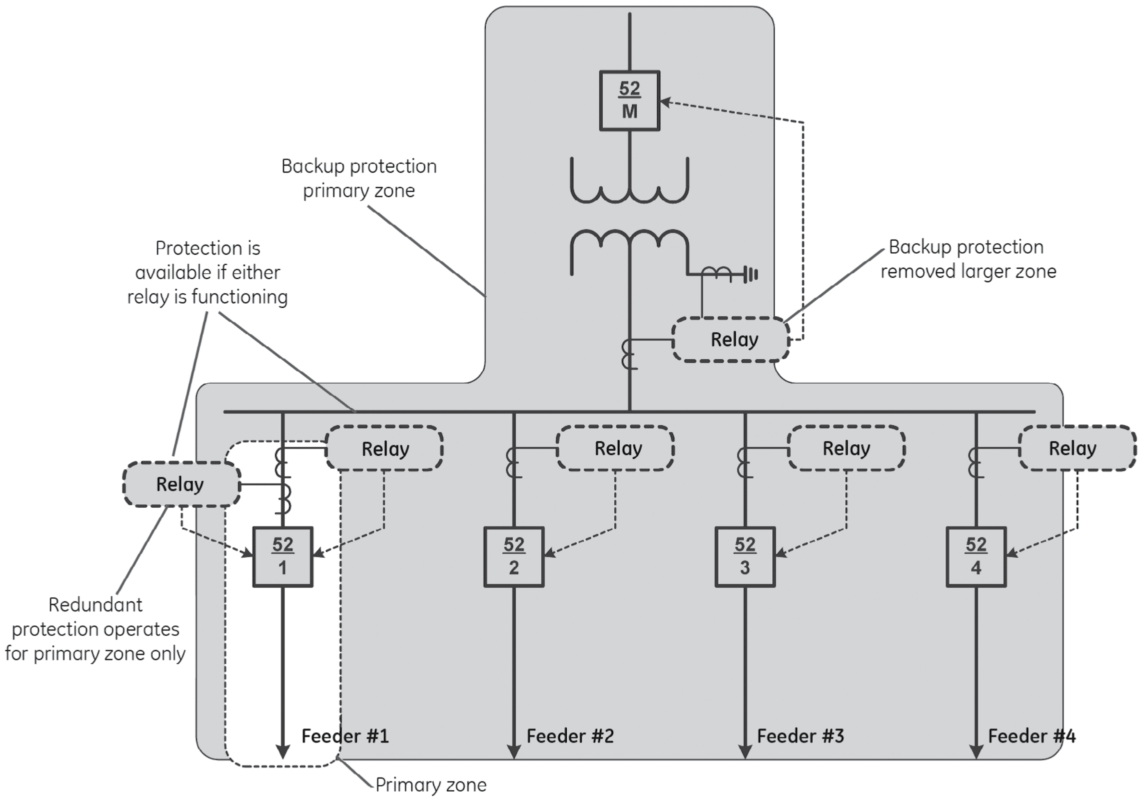

Figure 1. Redundant Protection and Backup Protection

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 effciently 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 trans-mission 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 perfor-mance. 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.

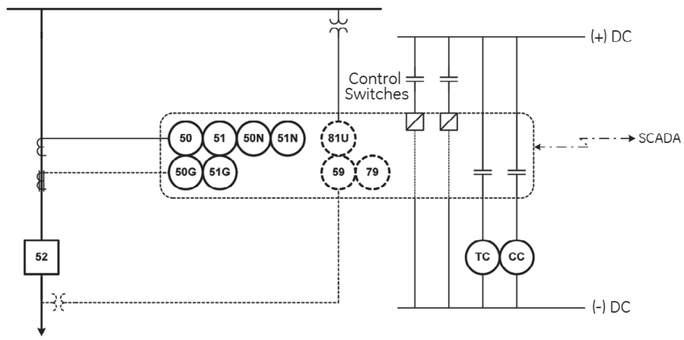

Figure 2. Feeder AC and DC schematic (simplified)

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 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.

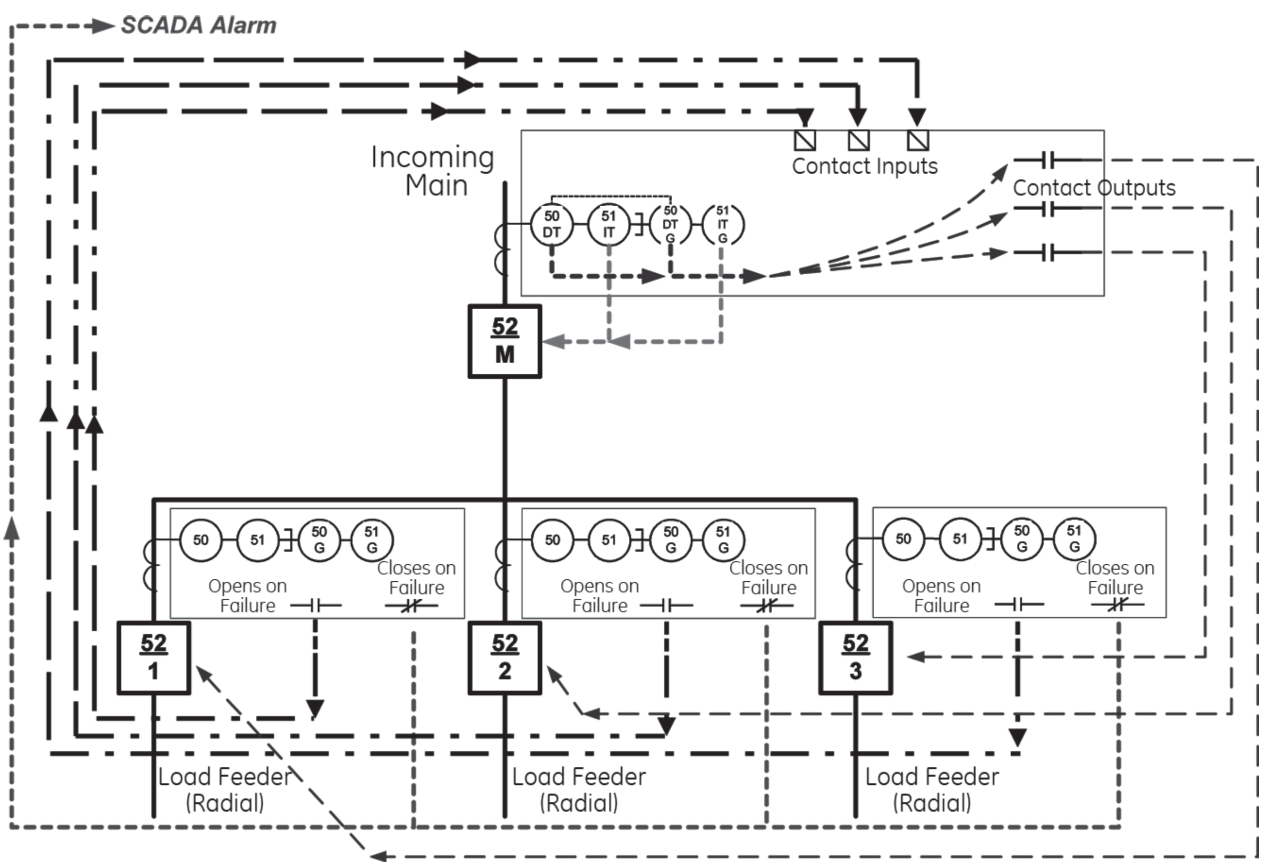

Figure 3. Accelerated Backup Scheme

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.

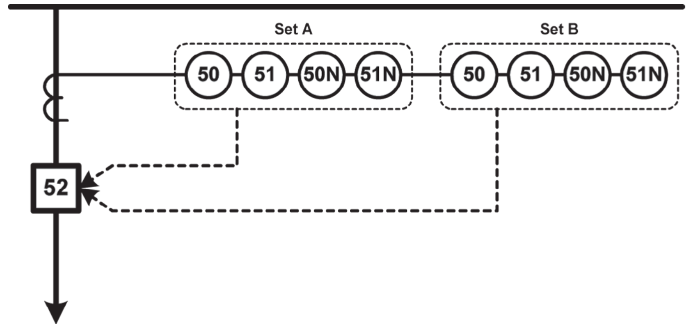

Figure 4. Dual Redundant Relay Protection

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.

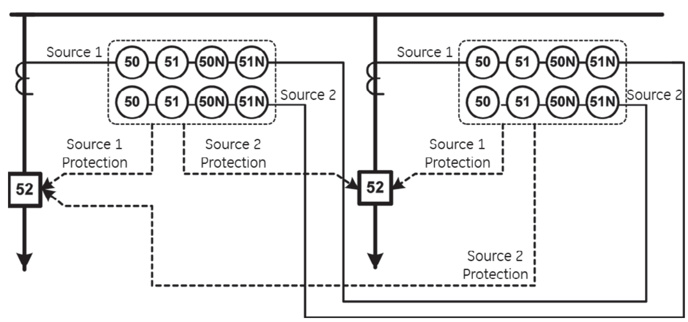

Figure 5. Feeder Relay Pairs

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.

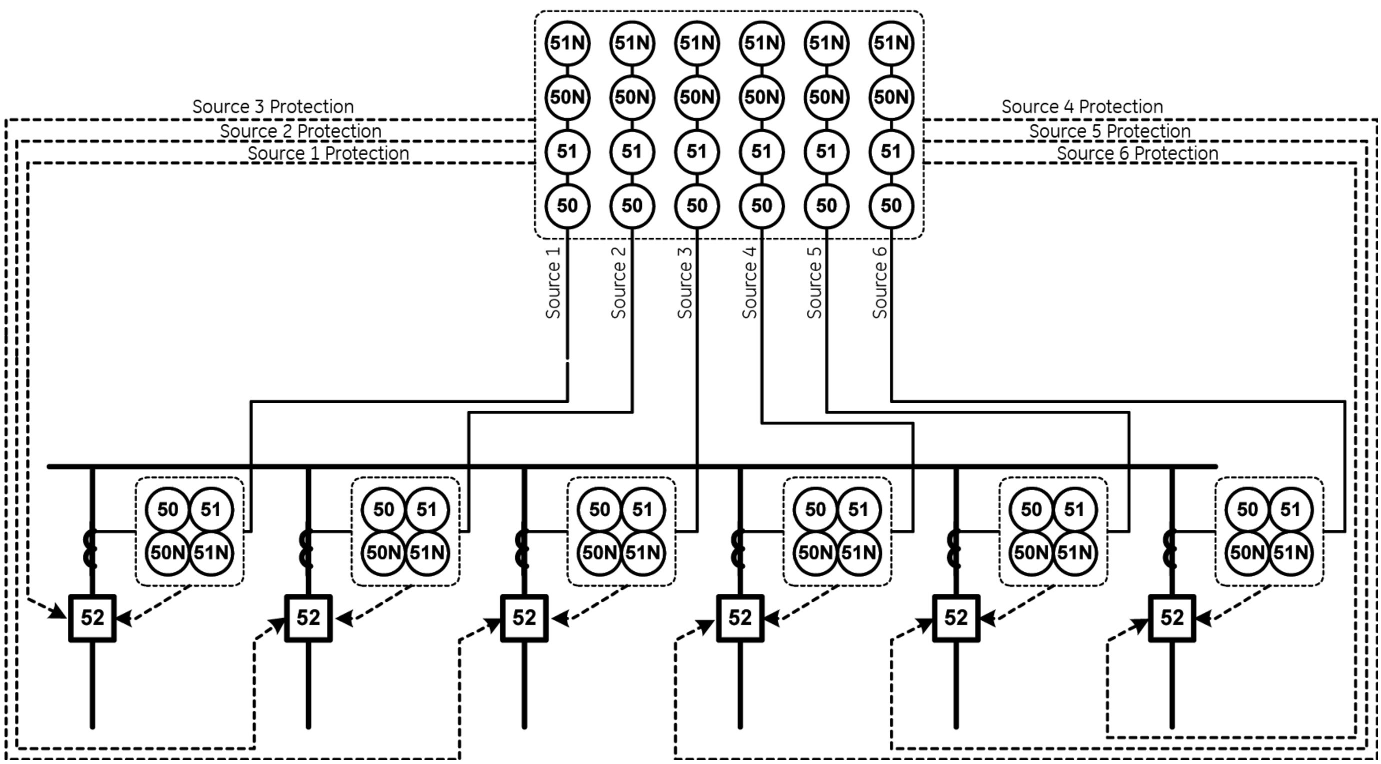

Figure 6. Multiple Source Feeder Relay

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.

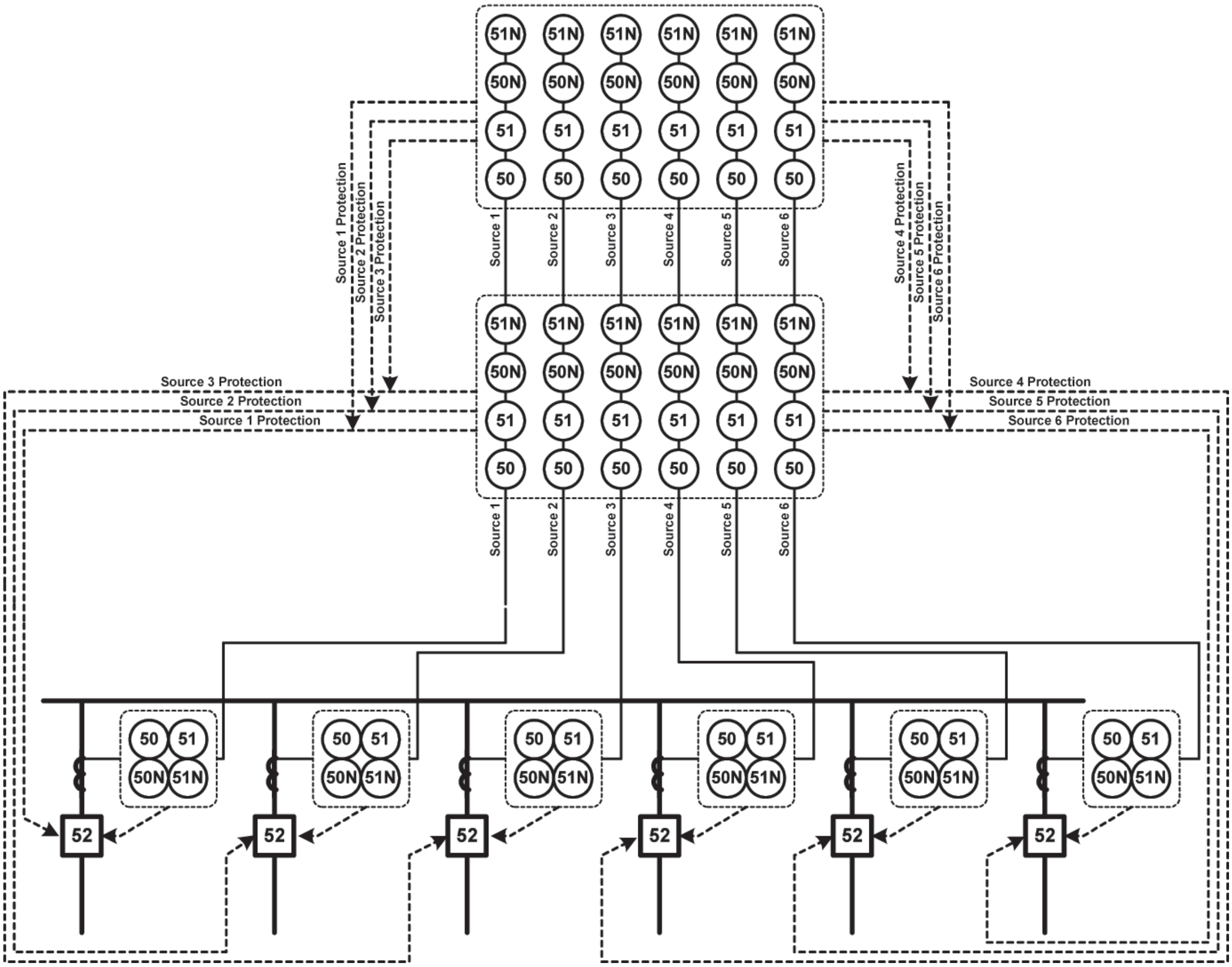

Figure 7. Multiple Source Feeder Relay as Set A / Set B

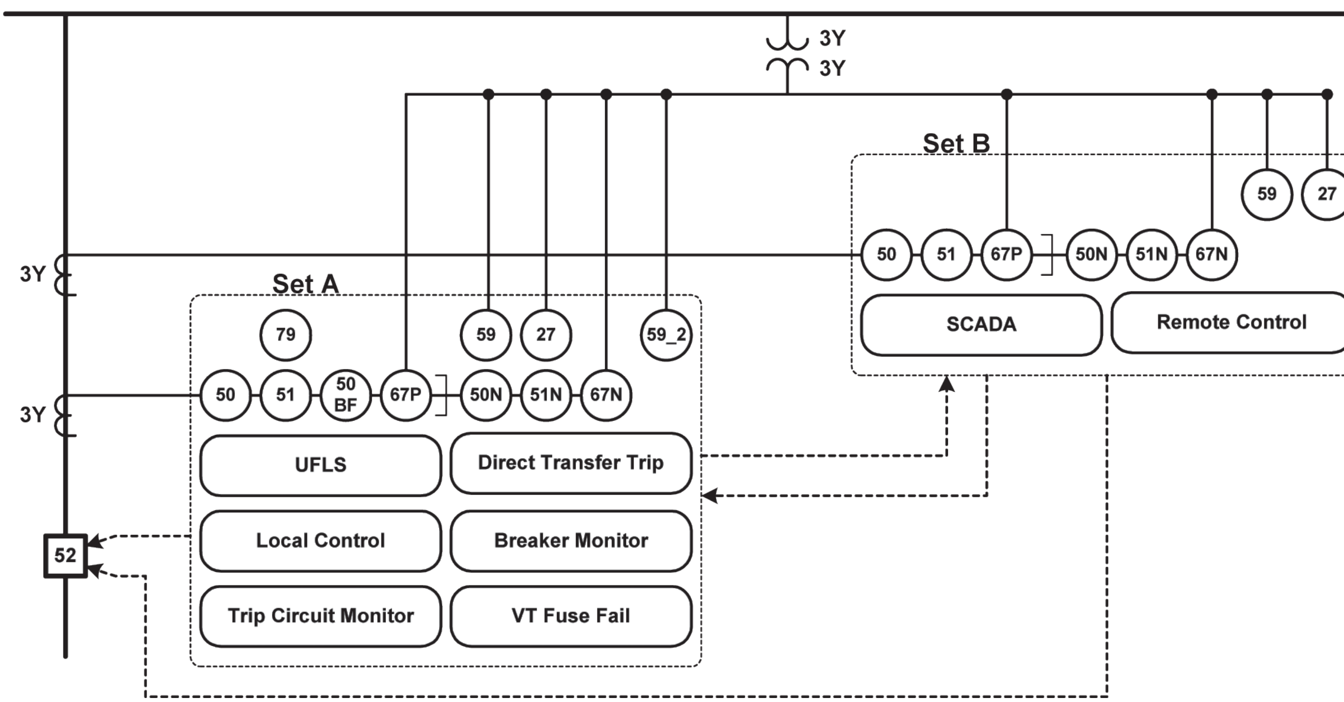

Figure 8. IPAC System Redundant Protection

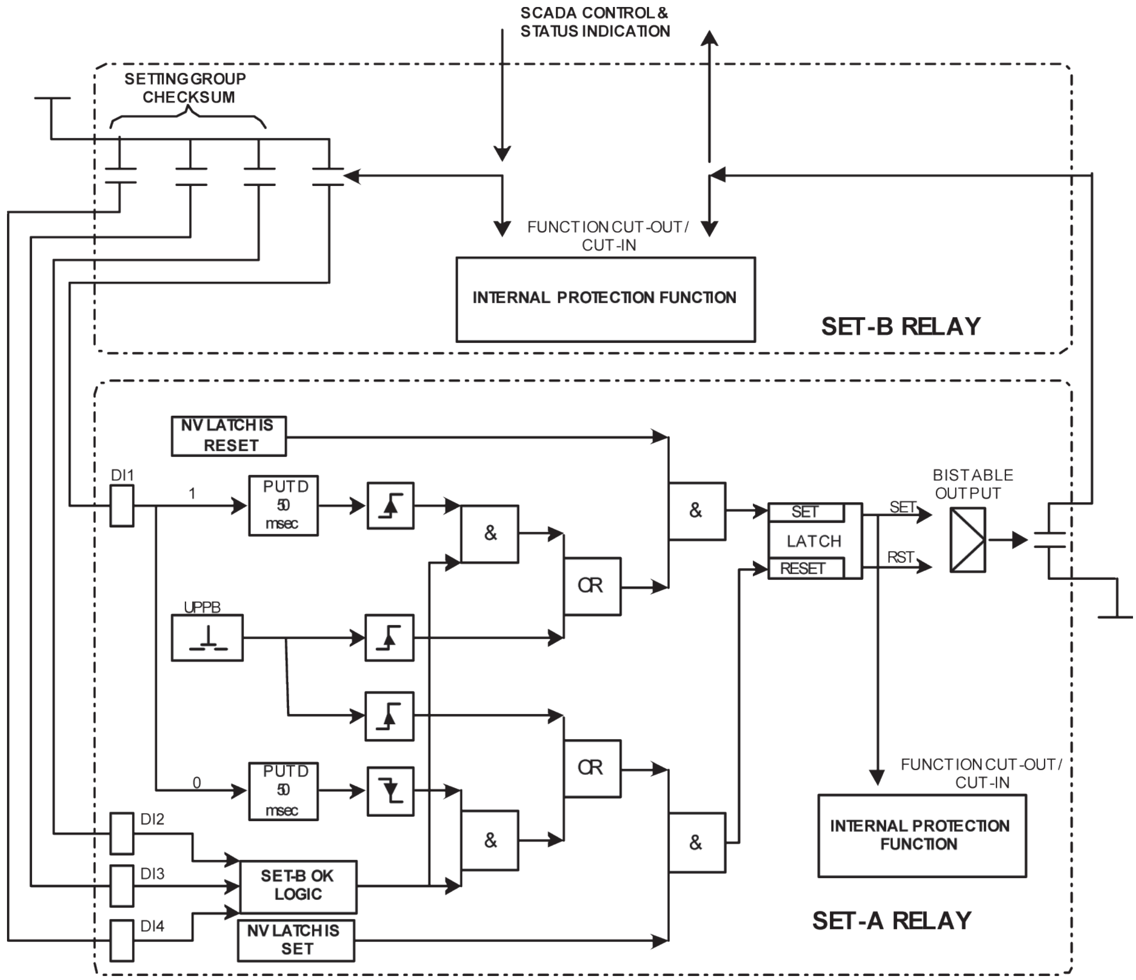

Figure 9. Generic Cut In / Cut Out Switch Logic

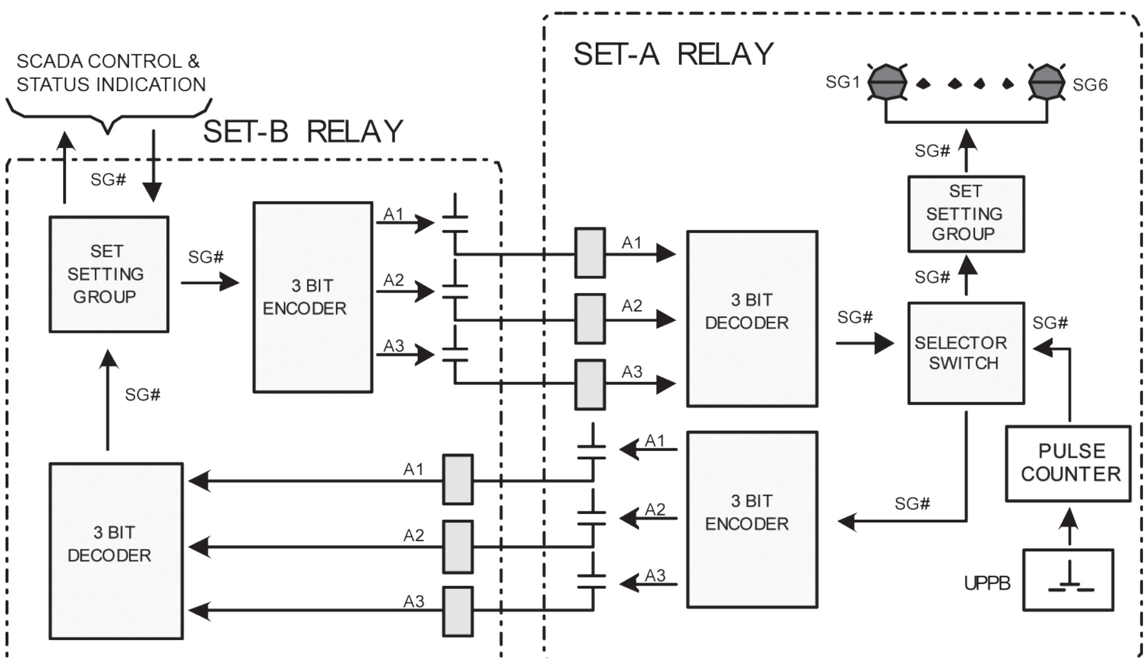

Figure 10. Setting Group Simplified Block Diagram

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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