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STANFORD UNIVERSITY, PALOU SUBSTATION MODERNIZATION PROJECT

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ABSTRACT

Stanford University embarked upon a project to modernize the protection and control systems at their Palou Substation. This substation provides the main interconnection point for two 60 kV utility tie lines, a tie to a cogeneration facility, and three transformers that feed the distribution system to the campus. The two utility tie lines are normally operated in a preferred/standby arrangement. The bus can be sectionalized to allow multiple operating arrangements, as the needs require. The project included an innovative, zone-interlocked directional comparison bus protection system that can adapt to any bus-sectionalized arrangement. An automatic power failure separation and restoration scheme is also included. One of the reasons for upgrading the system is to allow the campus to island on the cogeneration system during an outage of the normal utility tie line. This required the ability to transfer control of the utility tie breakers to the cogeneration facility via a redundant fiber-optic link to allow them to resynchronize with the utility after a successful islanding operation.

INTRODUCTION

In 1999, Stanford University embarked upon a project to upgrade and modernize the Palou Substation. This substation provides the main interconnection point for two 60 kV utility tie lines, a tie to a cogeneration facility, and three transformers that feed the distribution system to the campus. The project involved upgrading two of the transformers for increased capacity, rearranging the bus for improved operating flexibility, replacing aged equipment, and modernizing the protection and control systems. The focus of this paper is the modernization of the protection and control systems.

The Palou Substation provides the main interconnection point between the utility grid and the Stanford University distribution system. Figure 1 shows the final single-line arrangement of the substation. There are three sources into the bus: preferred utility tie line, standby utility tie line, and the cogeneration facility. There are three loads tapped off the bus: one small 4.16 kV transformer and two larger 12.47 kV transformers.

The project involved rearranging the bus to provide flexibility to feed the campus loads from any of the three sources, as conditions warrant. The flexibility of the bus-switching arrangement presented challenges to a traditional bus protection system, but those challenges are addressed by the new protection system. The new control system provides remote control of the utility tie breakers for synchronization in the event of a successful islanding of the campus on local generation. It also provides automatic load restoration in the event that islanding is unsuccessful.

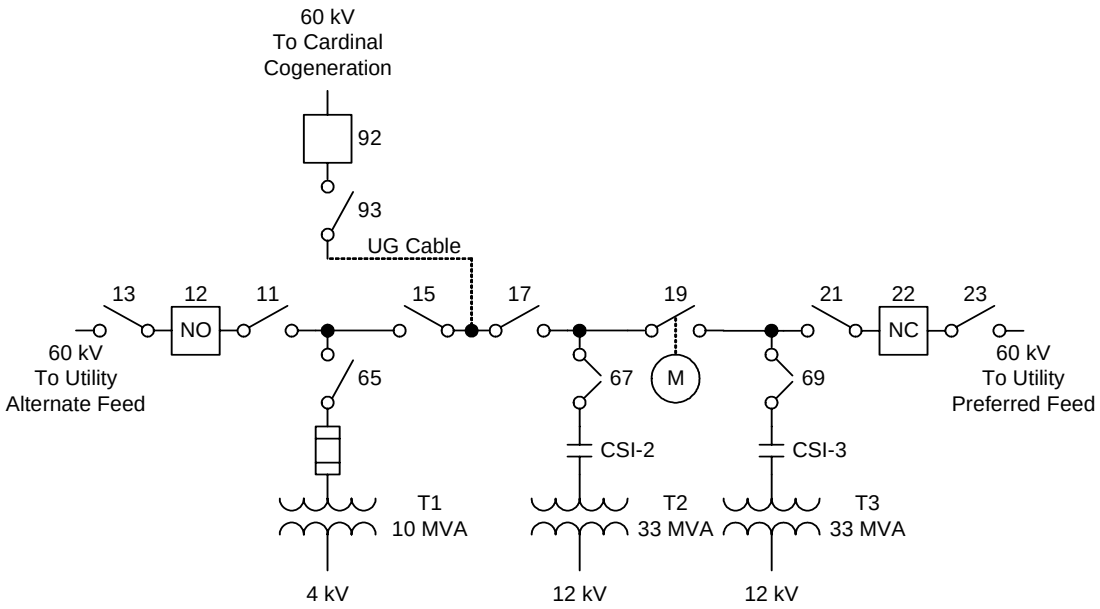

Figure 1 Palou Substation Single-Line Diagram

BACKGROUND

Located adjacent to Palo Alto in the San Francisco Bay area, Stanford University is more than a medium-size city unto itself—it is a highly developed and complex campus with facilities and services that are far more elaborate and strategic than those of the typical community of 20,000. Yet, with a profusion of research and medical teaching centers, plus housing, classrooms, sports, and cultural complexes, it is one of the most energy-efficient institutions among California's research universities. There are 678 major buildings at Stanford (12.6 million total sq. ft.), plus 843 owner-occupied faculty housing units on campus. Stanford has three substations for the distribution of electrical energy. Palou Substation is the primary substation for distribution to the University campus.

Palou in 1943

The Palou Substation was initially installed in 1943. At that time, only one 5 MVA, 60 to 4.16 kV transformer was installed. Only 4160-volt distribution was available on campus.

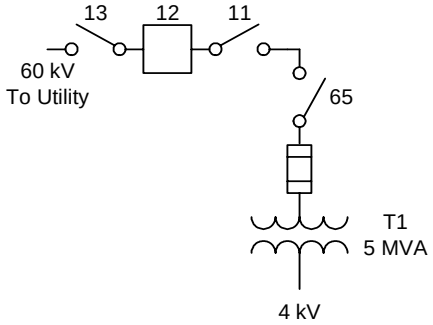

Figure 2 Stanford Palou Substation, 1947

Palou in 1954

In the 1950s, the addition of one 12 MVA (FOA), 60 to 12.47 kV bank provided the power for six additional distribution circuits across the campus (Figure 3). A second interconnection point was made to the local utility.

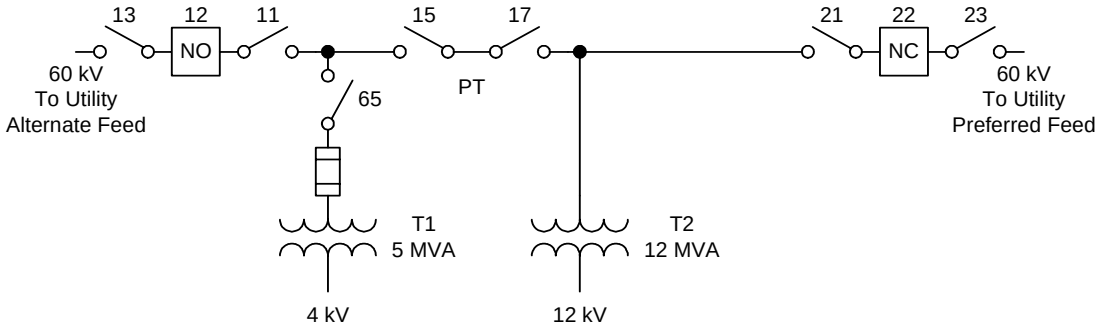

Figure 3 Stanford Palou Substation, 1954 Additions

Palou in 1987

In 1986, in anticipation of the project to install a campus 50 MW cogeneration unit, an additional 16 MVA (FOA) transformer was installed, and the original 12 MVA transformer was replaced with a 16 MVA (FOA) (Figure 4). The 4160-volt, 5 MVA transformer was also replaced with a 10 MVA unit. Total available capacity at that time was 42 MVA.

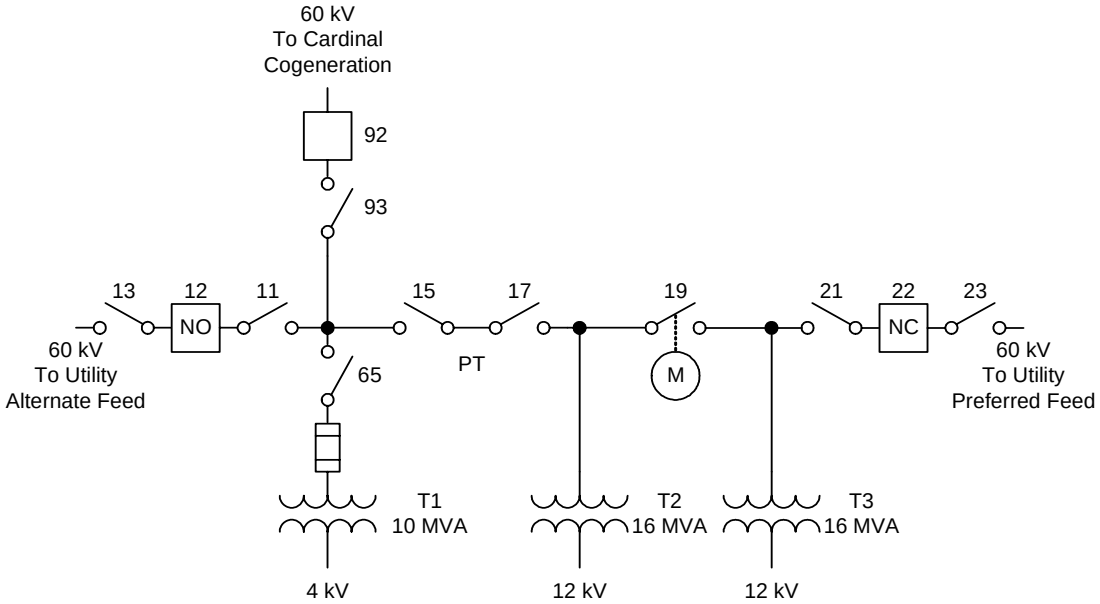

Figure 4 Stanford Palou Substation, 1987 Additions

Palou in 2004

In 1998, the power demands of the campus were increasing at an average of about 4 percent per year. Fast firm capacity had been outstripped. Equipment was old and obsolete, some approaching 50 years old. A multifaceted project was implemented to:

1. Increase the available fast-firm transformer capacity from 42 to 76 MVA with the present loads. Transformer banks 2 and 3 are redundant, with an automatic transfer scheme applied on the main-tie-main of the 12.47 kV bus. In addition, another transformer bank 4 (not shown) feeds from the 12.47 kV to the 4.16 kV bus and backs up transformer bank 1.
2. Replace two 50-year-old oil circuit breakers with SF6 breakers.
3. Replace the open bus capacitor banks for enclosed units.
4. Replace the 60 kV control switchboard and electromechanical relays with a new modern control and relay system.
5. Install relaying to allow "islanding" of the cogeneration and campus when the utility sources are tripped offline.
6. Move the cogeneration connection on the substation 60 kV bus to provide for more reliable operation and switchability.

Figure 1 shows the final configuration of the Stanford Palou Substation.

Figure 5 Palou Substation, February 2004 (Transformer Banks 1, 2, and 3, Left to Right)

PROJECT OVERVIEW

Substation Equipment Upgrade

Increasing the fast firm capacity of the transformer banks required the removal of the two 16 MVA units for 33 MVA units. This project was accomplished with zero campus electrical outages. Load was transferred to other sources. Transformers were replaced and commissioned back into service, one at a time. Construction crews worked in an energized substation for the duration of the project.

Figure 6 33 MVA Transformer During Installation

In 1987, the cogeneration plant connection had been installed at the most physically convenient location on the bus. This afforded no ability to isolate sections of the substation bus for necessary repairs or maintenance without shutting down the cogeneration plant. The reconnection in the center of isolation switches 15–17, closer to circuit breaker 22, has now provided the ability to maintain and repair any section of the 60 kV bus without disrupting cogeneration.

Protection and Control System Upgrade

Changing out of the substation obsolete equipment was completed by the summer of 2002. During this construction, it was determined that fault protection of the new equipment was not adequate and that an accelerated plan was required to reconfigure and completely upgrade the relay, control, and protection scheme.

Figure 7 Palou Substation—Obsolete Oil Circuit Breaker (OCB) on Left

Figure 8 Palou Substation Looking North—Modernization Completed

For many years, it was recognized that the controls and relays for the substation protection were old, and had been added piecemeal into the substation controls over several years. Various devices had no replacements. A number of relays buzzed, and no amount of maintenance could correct them. In addition, it also did not seem prudent to protect the new equipment with old obsolete relays, old relaying schemes, and old controls.

Another unreliable aspect of the existing relay scheme was the inability of the campus to stay online during utility transmission problems. This unreliability was corrected by the addition of specific relay functions that tripped the utility connections and maintained the cogeneration tie.

Like the substation equipment, the six sections of existing control and relay panels were piecemealed together, in stages, over the life of the substation. In 1954, the original two sections were installed, followed in 1974 with two more, and the final two sections were installed in 1987. The 50-year old wiring insulation was dry and crumbled at the touch.

Figure 9 Palou Substation—New Protection and Control Panels

Removing the existing 125-volt dc battery bank to another building opened up space for the new panels to be installed prior to the removal of the old sections. Stanford high-voltage electricians were able to replace the station wiring in sections. Relay commissioning was accomplished in bus

sections, without disruption to the outbound power flow and generation. Again, no inadvertent, accidental outages were experienced during this hot system change over.

Overview of Protection and Control System Upgrade

Description of Old Relaying Systems

For many years, Stanford personnel were pondering and debating the possibility of using the cogeneration system for islanding the campus during extended utility outages. There were several drawbacks to implementing this idea. The utility interconnect requirements are not enforced retroactively. However, if changes are made to the service entrance, the utility will request that the consumer implement the latest standards. The cogeneration system had not changed in 20 years. The required under-/overfrequency and under-/overvoltage relays were located at the 12 kV level on the load side (looking out) of the step-up bank 12 kV breaker. It was readily apparent that these relays had to move to the 60 kV level to trip the utility tie-line circuit breakers, 12 and 22, in the event that the utility's local system was collapsing. Palou Substation power from the cogeneration unit could be left online to feed the University.

The utility interconnect requirements are extremely rigid with respect to protection for cogeneration units. The existing protection at Palou Substation had also never changed in 50 years, as the original substation was designed as a loop feed. This protection consisted of electromechanical relays on each breaker as follows:

- Phase and ground overcurrent 50/51 and 50N/51N
- Directional phase and ground overcurrent 67/67N, with a trip direction away from Palou
- Zone 2 impedance relaying with trip direction away from Palou
- Partial overcurrent differential scheme with fault detection applied to all three sources on the substation bus
- One test reclose after a power failure and live line restored

The transformer banks 2 and 3 were solidly connected to their respective bus section with no fault interruption capability feature except that their respective protection tripped breakers 12 or 22. With this arrangement, the entire campus could be lost, including cogeneration.

System Modifications

The first phase (1999) of the Palou Substation modernization upgraded the banks to 33 MVA (FOA) and added circuit switchers for transformer bank isolation.

The second phase of the project was started in 2002 and consisted of:

- Replacing the two obsolete OCBs with SF6 breakers.
- Replacing the old obsolete (troublesome) disconnect switches.
- Adding disconnects in front of the previously installed circuit switches.
- Installing two sets of three-phase bus PTs and a single-phase PT on the line side of each of the utility tie-line circuit breakers, 12 and 22.
- Reconnecting cogeneration such that it could be selected to two buses. This was accomplished by utilizing the old PT selector switch. This connection was also made with about 30 feet of 72 kV, 750 MCM copper conductor, because the structures were too close to modify.

Engineering tasks included:

- **Scanning of substation yard for underground conduits and ground wires.** This was performed by the Stanford Utilities Department.
- **Modifying the grounding system to meet NEC, NESC, and IEEE 80 standards**. There is a conflict between utility standards and the codes governing nonutility consumers. The utility grounding system was left in place and then extended to meet IEEE 80.
- **Scanning of old structural blueprints into CAD standards.** The 50-year-old blueprints were scanned and converted to AIA CAD standards.
- **Evaluation of the old structures and foundations for seismic withstand.** The latticework structures were found to be adequate by today's standards. The utility-designed substation was built to 115 kV standards. This left enough spacing in the bays to add potential transformer and switch structures. V-break switches were chosen because their compactness allowed fitting in the bays.

Control/Relay Panel Replacement

In contemplating the changes required for the additional protection at Palou and looking at modifying 50 years of wiring additions and changes, the Stanford personnel elected to replace the entire control/relay panel with state-of-the-art relays and controls.

In addition to the reasons mentioned earlier, further reasoning for the replacement was:

- The islanding relays could be moved to Palou.
- There was less risk to losing the campus due to inadvertent and unknown conditions in the cobweb of wiring that existed to and from and within the control room building.
- Proper selective tripping could be achieved from the three utility substations.

Protection Challenges of a Nonutility-Owned Substation

Every utility expects its consumers to comply with its protection requirements. This includes coordination (not necessarily selective tripping) with its phase and ground time overcurrent relays.

In most instances, this requires the consumer to use instantaneous trips in order to coordinate with the time-overcurrent relays of the utility. As illustrated in Figure 10, the utility requires a 0.35-second time differential between their station relays and the consumer's relays.

In the case of Palou, this would mean adding instantaneous trips to the two utility tie-line circuit breakers. Because the transformer feeders are also equipped with instantaneous trips, there would be no selective tripping for bus faults between the utility tie-line breakers and the feeder breakers. For this reason, it was necessary to upgrade the bus protection system to provide high-speed, selective tripping for faults in this zone.

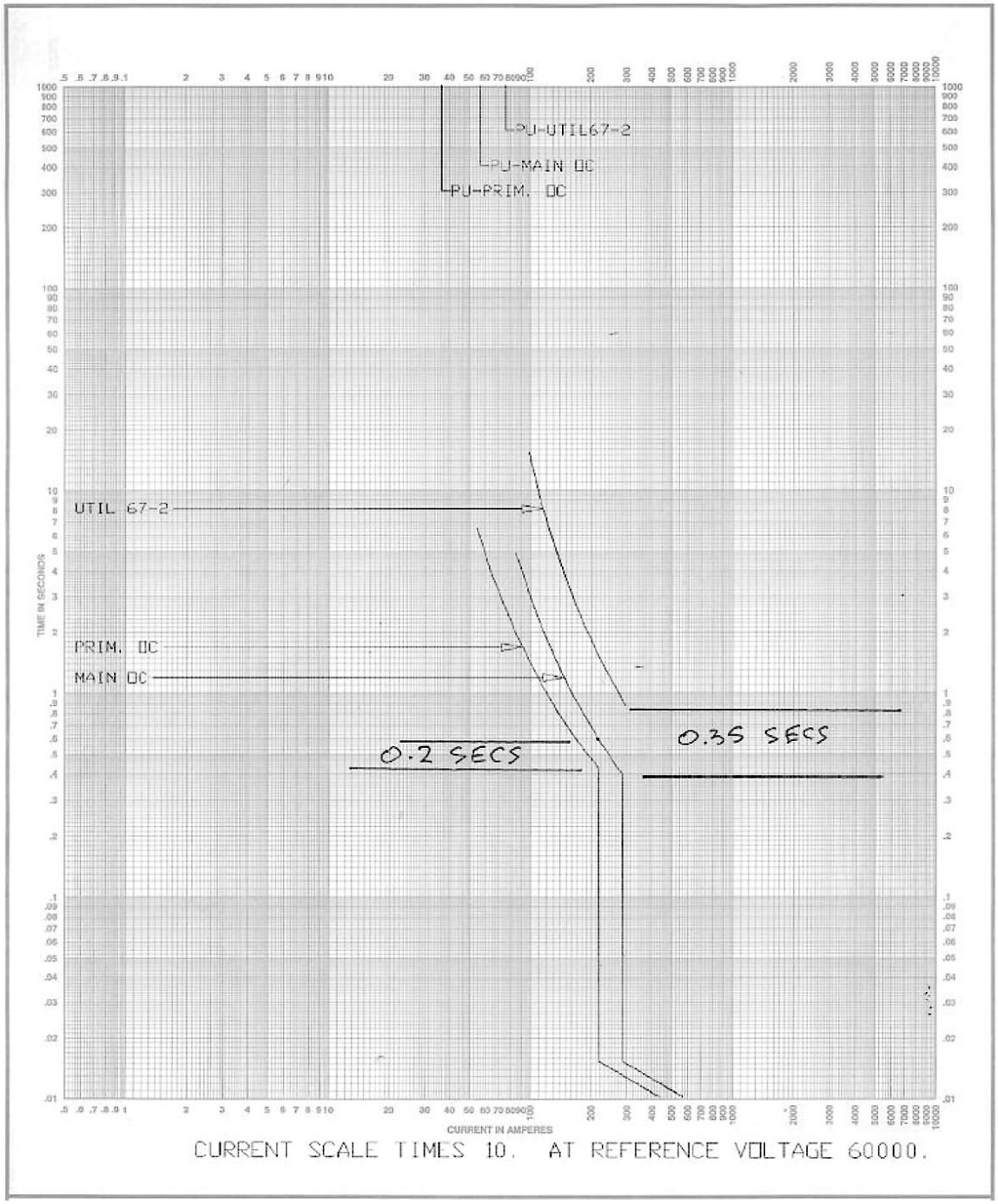

Figure 10 Overcurrent Coordination Challenges

New Protection Design

The new protection system design is shown in Figure 11. Multifunction relays were chosen to provide the many functions required to achieve the following goals:

- Selective tripping with the utility and the cogeneration relays.
- Selective bus protection for the 60 kV bus.

- Islanding protection at the 60 kV level with the under-/overvoltage and frequency relaying.
- Redundant relaying to meet utility requirements.
- Remote control and synchronizing from the cogeneration control room.

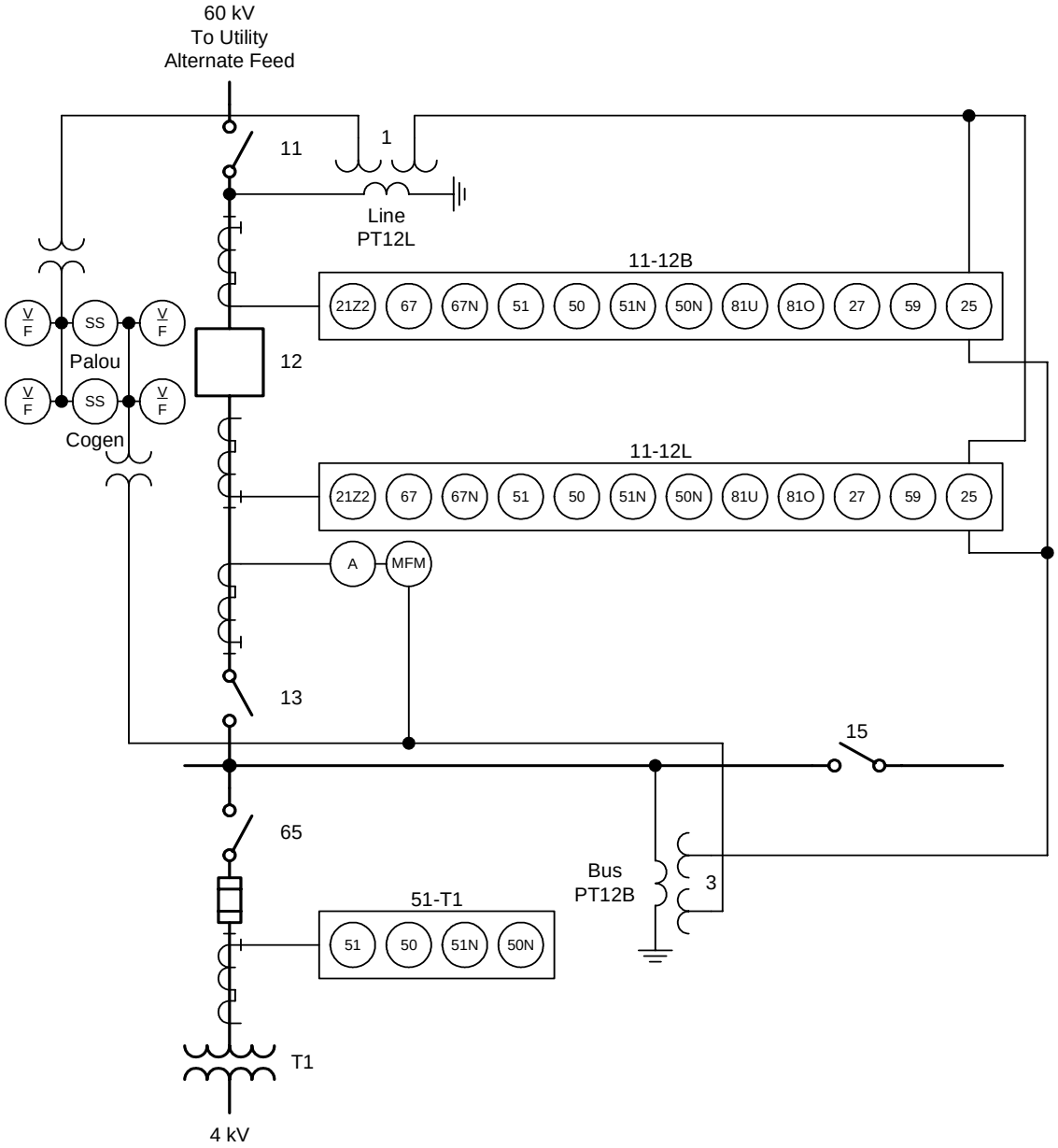

Figure 11 Partial Meter/Relay One-Line Diagram, New Protection System

PROTECTION SYSTEM DESIGN DETAILS

The protection system had to be upgraded to make successful islanding a possibility. The relays on the utility tie circuits needed excellent sensitivity and selectivity to reliably detect faults on the utility system, and they had to operate quickly to enable the local generation to remain stable. It

was necessary to add under-/overfrequency and voltage protection relaying at the utility tie point and coordinate it with the generator protective relays to prevent tripping the local generation during recoverable disturbances.

The upgraded protection system also had to meet utility requirements for reliability. Redundant protection is required to ensure that faults on the Palou bus and feeders do not result in tripping of the utility circuits, which would adversely affect reliability for utility customers.

Two identical multifunction distance relay systems are used on the utility tie circuits. Both relays are programmed for zone 2 distance phase protection with ground directional overcurrent. The relays also provide the first stage of tripping for over-/undervoltage and over-/underfrequency conditions. The two relays are programmed identically except for the inverse-time overcurrent backup elements. The utility also required that the bus zone protection be redundant so a dual directional comparison bus protection scheme is installed. The following section will elaborate on the bus protection system.

The load and cogeneration circuits are one zone away from the utility, so they did not require that the protection for these zones be fully redundant. Each branch circuit includes a single new multifunction directional overcurrent relay system. However, the original protection remains in place on these circuits so they also have redundant protection.

It is important to note that the 4.16 kV distribution bank, T1, was not upgraded, and it is still protected by high-voltage power fuses. The next phase at Palou will replace the fuses with a circuit switcher. This circuit still received a new multifunction relay to provide information on that branch circuit for the directional comparison bus protection system.

Overcurrent Element Coordination

In order to segregate the phase coordination from the ground coordination, it is desirable to prevent the phase elements from operating unless it is a multiphase fault. For many years, electromechanical relays have dictated the relaying standards. The ability of the phase overcurrent relays to detect ground faults has also continued into many microprocessor relays. On numerous industrial systems, one main and several feeder breakers will feed numerous transformers with primary fuses. Another arrangement is to have a main breaker and fused switches for feeders. The majority of faults on distribution systems are line to ground. Common fault occurrences are to have the fuse and the phase instantaneous relay respond to ground faults on the load side of the fuses. On typical distribution systems, the phase elements will also respond to ground faults, and operations personnel will find targets operated on both phase and ground relays.

Figure 12 shows a typical coordination curve where the industrial user is forced to use instantaneous trips on the phase relays, and the ground relay is only time overcurrent. As can be seen from this typical time current curve, even though the time-overcurrent phase elements are coordinated with the fuses, there is an area of nonselectivity between the instantaneous trips and the feeder fuses. In addition, there is no coordination between the time-overcurrent ground relay and the fuse curve above one tenth of a second.

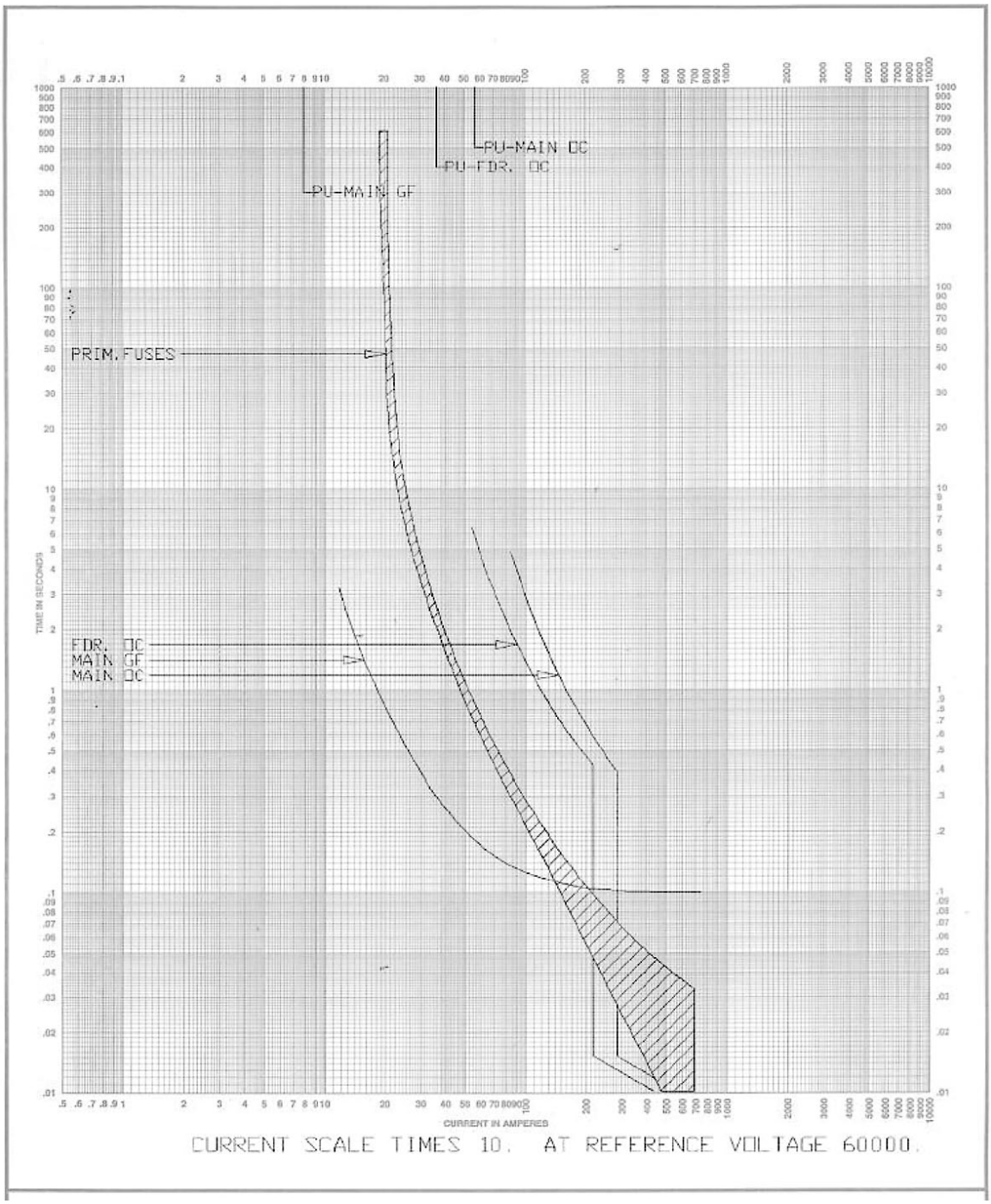

Figure 12 Phase and Ground Overcurrent Coordination Challenges

Programming the main and/or feeder phase overcurrent relays to respond only to multiphase faults removes the area of nonselectivity from the tripping sequence. This now allows a chance for the fuses to clear the ground fault and allow the feeder (or main) to stay online. With modern programmable relays, this is easily accomplished. Figure 13 shows logic that allows a phase overcurrent trip only if more than one phase element picks up.

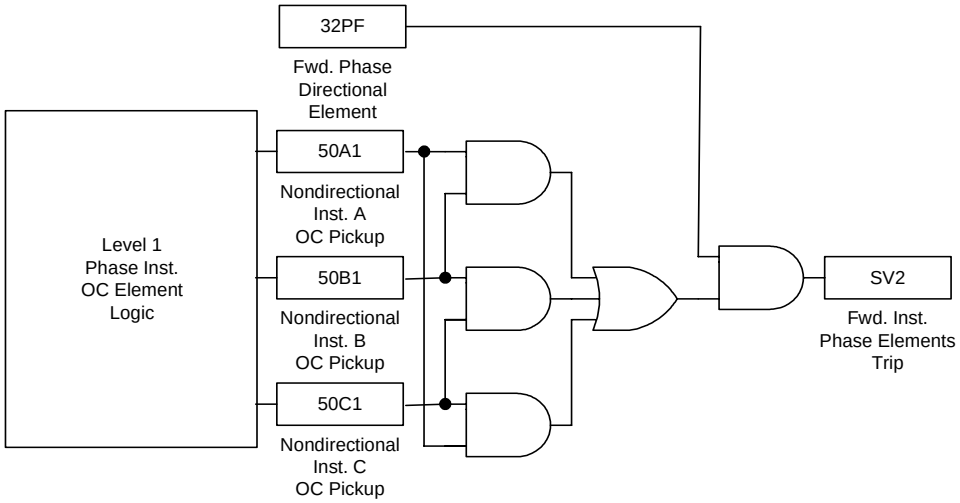

Figure 13 Phase Overcurrent Element Logic

Bus Protection System

One of the objectives of the redesign of the substation was to improve operational flexibility to allow multiple ways to feed the campus load and allow export of power from the cogeneration system in the event of an outage of the normal utility tie line. As part of the project, the cogeneration circuit was moved to a position in the middle of the bus. This makes it adjacent to the 12.47 kV and 4.16 kV campus load circuits and allows it to export power via either utility tie line. As can be seen in Figure 1, sectionalizing switches between each branch circuit allow the bus to be reconfigured for nearly any contingency. This flexibility posed a challenge to traditional bus differential protection schemes, because when the system is operated with the bus split, the bus protection system should be selective and trip only the faulted section of the bus.

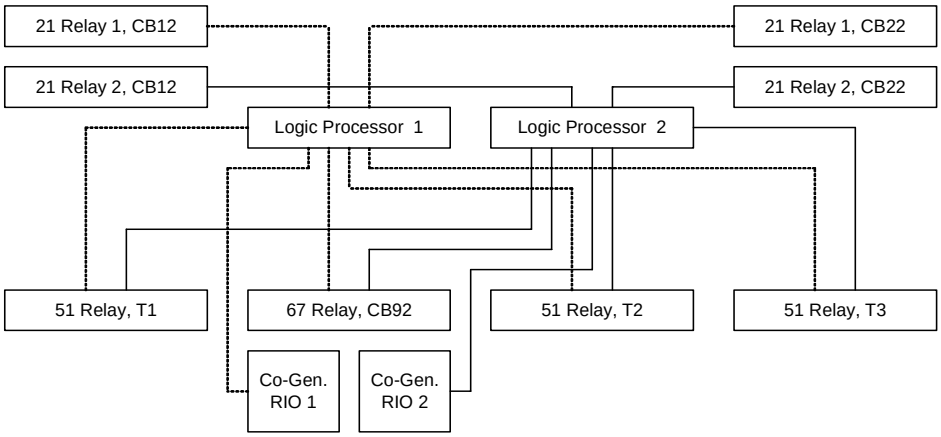

Figure 14 Serial Communications Logic Interconnect

The solution was to utilize the directional information from the relays on each of the branch circuits to determine if a fault is internal or external to the bus. Each relay sends status information on its circuit via a serial communications link to a logic processor (Figure 14). The bus protection system resides in the logic processor. If the logic processor determines that a fault is internal to the bus, all of the source breakers to the bus are tripped via the reverse path of that same serial communications link.

The basic scheme is shown in Figure 15. It works very much like a traditional directional comparison blocking (DCB) line protection scheme. If any relay sees a fault towards the protected zone (LV11) and no relay sees a fault away from the protected zone (SV10), tripping occurs. The 12 ms pickup, PU, timer (SV11T) is a communications coordination delay. The "fault towards the bus" (tripping) logic must wait 12 ms to allow any blocking signal to arrive. The 32 ms dropout, DO, timer is there to ensure that the trip signal is transmitted for a minimum amount of time required for tripping to occur. The 16 ms PU/160 ms DO timer (SV10T) provides security to prevent tripping when an external fault is cleared. If a block signal is received for 16 ms, the block is held up for 160 ms upon reset to prevent tripping if the blocking relay resets before the tripping relay does. This is another common feature borrowed from traditional DCB line-protection schemes. Notice that there are only three inputs to the LV11 OR gate—one for each source breaker. There are six inputs into the SV10 OR gate—one for each circuit.

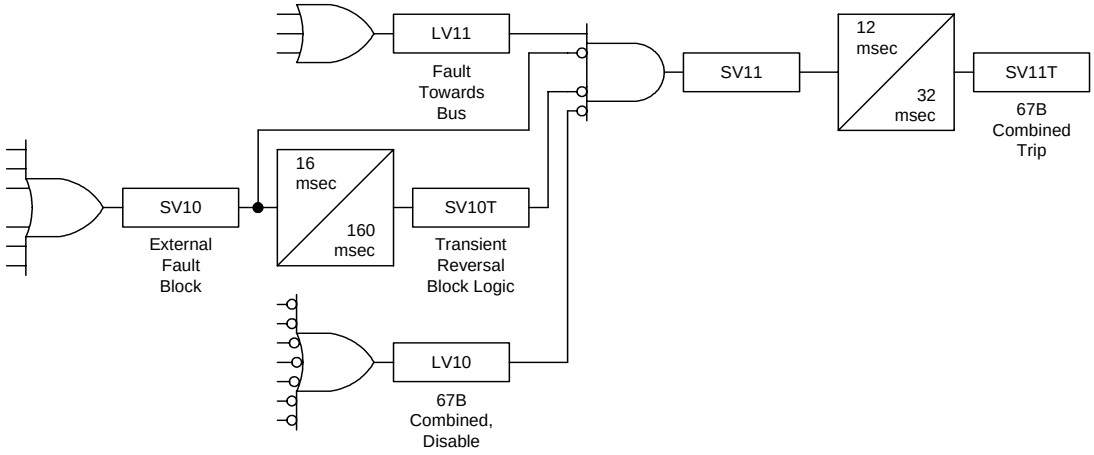

Figure 15 Directional Comparison Bus Protection Logic

Figure 16 illustrates how the system would work for a fault on the utility system. For this fault, Device 67–92 would see the fault as towards the bus and send a tripping signal. Device 21–22 would see the fault as away from the bus and send a blocking signal. Device 21–22 would not operate because its breaker is open. Devices 51–T1, 51–T2, and 51–T3 would not operate because there are no sources on these circuits.

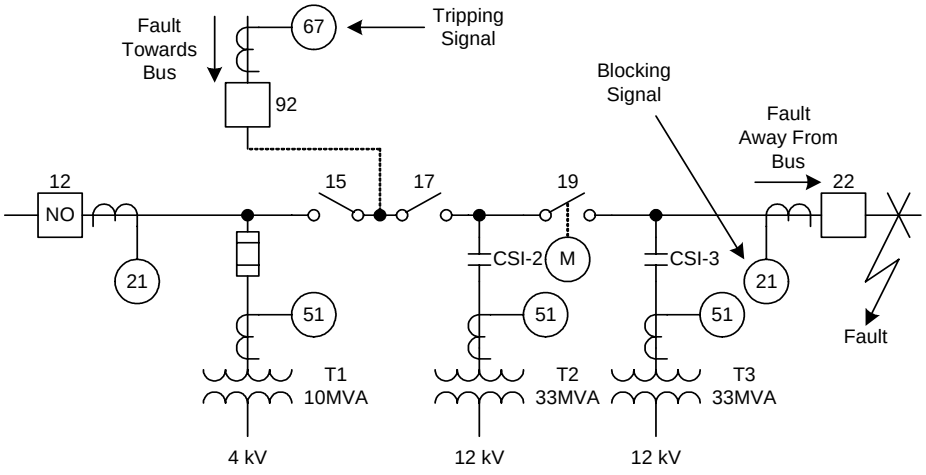

Figure 16 Bus Protection Operation for an External Fault

In any blocking scheme, communications reliability is important. If a block signal is not received for an external fault, the scheme can overtrip. OR gate LV10 provides logic to disable the scheme. This logic asserts if communication is lost to any of the relays. Under this condition, the scheme would not know the status of that circuit and would be prone to overtrip for an external fault on that circuit. The scheme is also disabled if the directional relays on the source breakers have a loss-of-potential (LOP) condition. Under this condition, the directional decisions might be unreliable.

The load circuit relays do not need to be directional. They send a “fault away from bus” (blocking) signal only if they pick up for a fault on their circuit. If any of the load circuit protective devices do pickup momentarily due to rotating loads backfeeding an internal fault, the block signal may slightly delay tripping. This spurious block signal would have to be present for 16 ms before the block is sealed in by the transient block logic (SV10T).

Each of the source breaker relays must send three bits of data, as shown in Figure 17:

- Loss-of-potential status
- Fault towards bus
- Fault away from bus

These relays must be directional. The “fault towards bus” (tripping) elements must be coordinated with the “fault away from bus” (blocking) elements. In other words, no tripping element can be set more sensitively than the least sensitive blocking element.

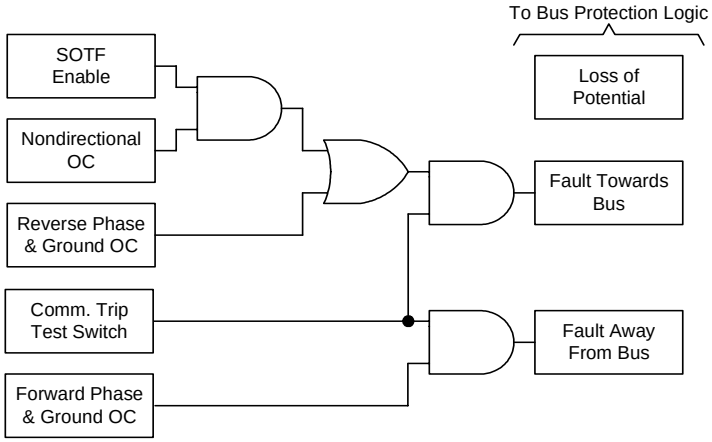

Figure 17 Source Circuit Transmit Logic

Additional features need to be included in the source circuit relay logic to make the scheme dependable and secure. Because the potential transformers for these relays are on the bus, it is necessary to include switch-on-to-fault (SOTF) trip logic in the tripping signal, in case the bus is energized onto a bolted fault where the lack of polarization may prevent the relay from operating.

Another consideration is isolating a relay from the scheme when it is out of service. Because the tripping signals to the bus logic do not go through physical output contacts, it is not possible to open a test switch to prevent accidental tripping of the bus when a relay is being tested. To address this challenge, a test switch was wired to a contact sensing input on the relay. The status of this test switch is ANDed with the fault direction signals. Thus, when the switch is opened, the tripping and blocking signals are blocked. In this installation, this same test switch is also used to block the bus trip coming in from the logic processor. In some cases, it might be desirable to use a separate test switch for outgoing trip signals and incoming trip signals.

The logic scheme shown in Figure 17 is one of four in each logic processor. This one is for the "bus combined" condition. If any of the bus-sectionalizing switches is open, this logic is disabled. When the bus is sectionalized, each source circuit has its own logic. Depending upon the sectionalizing switch status, only the branch circuits that are connected to that source circuit's bus section are included in the scheme. And only the source breakers for the faulted section of the bus are tripped. This provides the desired selectivity to prevent tripping unfaulted sections of the bus.

As stated before, this system is redundant. For the utility tie circuits that have dual relays, each relay communicates with one of the two logic processors. For the branch circuits with only one relay, each relay communicates with both logic processors. If both schemes are disabled at the same time, the source breakers also include independent time-delayed backup tripping. If the "fault towards the bus" elements remain asserted for 12 cycles, they will time out and trip their breaker directly.

Prior to the new panels being shipped to the substation, the scheme was fully tested. The testing involved staging 230 test procedures to ensure the security and dependability of the system for all combinations of internal and external phase and ground faults and combinations of bus-sectionalizing switch status. Tripping times for an internal bus fault are in the order of three cycles.

ISLANDING SCHEME AND REMOTE SYNCHRONIZING CONTROL

Several times in the past, upon loss of the utility under a no-fault condition, the cogeneration units have stayed online. The cogeneration operators are confident that no modifications are necessary to the governor or voltage regulator systems provided that the "off island" loads are cleared in a timely manner.

The utility has allowed an instantaneous trip on the underfrequency and time-delayed trips on the overfrequency and undervoltage. The overvoltage relay is set to clear instantaneously. The undervoltage and under-/overfrequency relays are coordinated with the relays on the turbine units.

Upon a successful islanding operation, the Palou bus must be resynchronized to the utility grid across one of the utility tie-line breakers. The generator excitation and governor systems must be controlled to match voltage and frequency to the utility grid before resynchronization can occur. Then the breaker must be closed just as the angular difference between the two systems is at a minimum. Thus, resynchronization must be controlled from the cogeneration facility. The cogeneration facility is approximately 1/4 mile from the Palou Substation. Redundant fiber-optic links are installed between Cardinal Co-Gen and Palou Substation. Fiber-optic links were used because they could be routed through the 60 kV duct banks. Each of the links is terminated in separate remote input/output (RIO) modules at the cogeneration facility and in the logic processors at Palou Substation. Each link can pass eight status points in each direction. The two links operate in parallel.

A remote synchronizing panel is installed at the cogeneration facility (Figure 18). Output contacts on the RIO modules are wired to indicating lights that show the operator the status of the utility tie-line breakers and the bus-sectionalizing switches. Close control switch contacts for each of the utility tie-line breakers are wired to contact inputs on the RIO modules. When the operator determines that conditions are appropriate to resynchronize the two systems, the contact closure from the remote control switch results in a contact closure on the logic processors at Palou

Substation. At Palou Substation, a local/remote switch, an auto/manual switch, and local synchronism check from the line relays supervise remote closing.

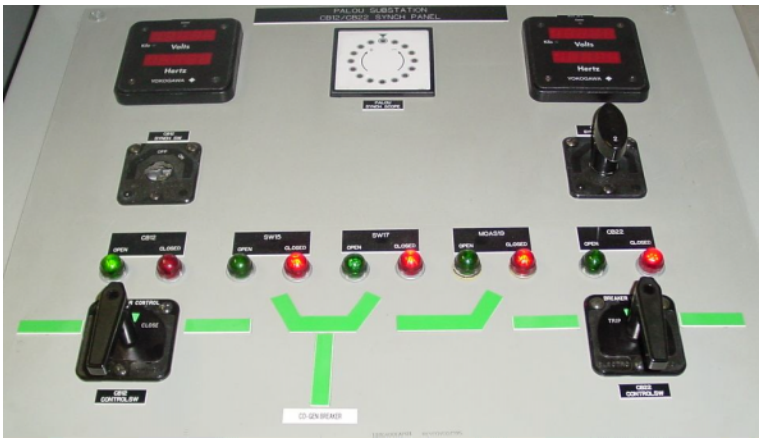

Figure 18 Remote Synchronizing Panel

AUTOMATIC OPERATION

In the event that islanding is unsuccessful and the Palou bus experiences an outage, automatic load restoration logic is provided by the logic processors. If the relays on the utility tie lines sense that both the line and bus are dead for a half second, they automatically open the tie-line breaker to wait for the utility source to be restored. If the standby utility source is hot, a 10-second reclose timer is started and the bus is automatically restored from the standby source. A five-second reclose timer on the preferred utility source will allow automatic restoration of the bus from the preferred source breaker if that source becomes available soon enough.

The utility requires that the power system never be looped through the Palou bus unless the utility has determined that system conditions are suitable for this to occur. With appropriate system switching, the utility does allow this condition for closed transition transfer between the two sources. However, it is necessary to ensure that under no circumstances can the two utility tie breakers be inadvertently closed simultaneously. Implementing the automatic restoration logic in the logic processors made it easy to include interlocking to prevent the auto-restore timers for the two utility tie-line breakers from initiating a close at the same time. This would be much more difficult to achieve if this functionality were implemented using two independent reclosing relays.

The automatic separation and restoration logic is supervised by an auto/manual switch.

INTEGRATION, RECORDING, AND COMMUNICATIONS FEATURES

The Stanford University utility system uses a campus-wide energy management system (EMS) to monitor loading and system status. The microprocessor relays are integrated with the EMS system via a Modbus® link. A communications processor gathers relay target status from each relay in the system and forwards that to the EMS system. When a fault occurs, the system operators can read the targets remotely to aid in fast restoration of the system.

The communications processor also provides several other valuable functions:

1. A single point of access from the substation computer to all of the relays
2. Distribution of an IRIG-B time synchronization signal that ensures that all event reporting functions are time synchronized
3. In the future, an Ethernet link to the substation from the Stanford utility offices, which are located at the opposite end of the campus from the substation

A computer programmed with a simple event logging system is installed at the substation. An electrician can walk into the substation after an event and review a log of summary event information, such as time of trip, fault currents, relay targets, etc., from each of the relays. This information is displayed on the computer screen and logged to the hard disk for archiving.

The substation computer also provides several other valuable functions:

1. Relay settings management and database functions
2. Easy access to oscillographic recordings for display and analysis

DESIGN DOCUMENTATION

Traditional design documentation packages can fall short with a nontraditional system such as this. In this system, much of the protection and control functionality is in programmable logic instead of in dc control schematic logic. Many of the status and control signals are passed between devices via serial links and never become physical inputs or outputs. Traditional dc schematic diagrams cannot provide enough information to understand, operate, and troubleshoot the system. Adequate design documentation requires logic diagrams and communications diagrams in addition to the traditional ac and dc elementary diagrams.

The ac and dc elementary diagrams are very traditional. They show how the relay sensing and control circuits are functionally arranged. However, they include only a brief label with each programmable relay output contact that indicates its purpose. It is necessary to go to the logic diagram to fully understand what drives each relay output contact in the scheme.

To understand the importance of logic diagrams for a system such as this, it is helpful to draw a parallel between diagrams for a traditional control circuit and a system built on powerful programmable devices. Logic diagrams are equivalent to dc schematic diagrams. They allow the user to easily see and understand the functionality of the circuit. On the other hand, logic-setting equations in the relay settings file are functionally equivalent to wiring diagrams. They only allow you to see how everything is connected together; it is difficult to follow the circuit and understand its functionality.

Another advantage of a drafted logic diagram is that it can be adequately annotated. Logic can be grouped into easily digestible functional groups. Many logic variable names within a device can be quite cryptic. Variables such as intermediate logic variables and general-purpose timers may have no inherent meaning at all. A brief name or description can be associated on the diagram with the logic variable, making it much easier to understand. Figure 13 and Figure 15 show examples of annotation of user programmable logic.

It is not necessary to develop a unique logic diagram for each relay. Many of the relays have identically programmed logic. A single diagram that covers each different application is sufficient. For example, one diagram can apply to all three of the transformer high-side relays.

The logic diagrams are limited to showing only the user programmable logic. It is recommended to not represent any of the fixed logic that is coded into the relay. This will make the diagrams more difficult to create. It also opens the possibility that the information may not be correctly reproduced to represent the manufacturer's design.

Relay I/O interconnected with other devices via serial links is most easily shown in serial link I/O tables. This provides an easy summary of status and tripping signals that are interconnected between devices but do not show up on the schematic diagrams.

CONCLUSIONS

Stanford made several key upgrades with this modernization project that improved the overall flexibility and reliability of their power system:

1. The substation was upgraded and rearranged to provide flexibility to operate the campus and export cogeneration power under most contingencies.
2. Aging and difficult-to-maintain equipment was replaced with no load interruption.
3. Protection was upgraded to make it possible to successfully island the campus load on local generation.
4. Bus relaying replaced the nonselective utility tie-line breaker phase and ground relays and the bus relaying scheme is now selective, depending on which of the three bus-sectionalizing switches are open.
5. Coordination and selective tripping was achieved from the 12.47 kV buses back to the utility's station breakers, to the full satisfaction of the utility protection engineers.
6. Remote control of the utility tie-line breakers was provided, to allow resynchronization with the utility grid upon successfully islanding.
7. The substation was upgraded to modern microprocessor-based protection and control equipment to obtain their inherent advantages of improved reliability, event reporting, continuous self test, flexible programmable logic, etc.

At the start of the project, we had a great deal of concern about meeting the latest utility requirements for a cogeneration/utility intertie. However, throughout the project, the utility engineering and operations personnel were extremely helpful in working with us to upgrade and modernize protection.

The modern microprocessor-based protection and control equipment make system operation more efficient and reliable. Stanford electrical maintenance and operations personnel are now fully convinced that microprocessor-based relays and the information they provide are far superior to the electromechanical relays that were replaced—a view they did not hold before the start of the project. The complete design documentation package, which included logic diagrams, along with onsite training and commissioning support, helped everyone understand and feel comfortable with how this innovative, nonconventional design worked.

Because the new system is smarter, more flexible, and makes maintenance easier (without interrupting service), Stanford's ability to provide the campus with dependable electric power is greatly enhanced. The completion of this project not only provides Stanford with the ability to meet the ever-increasing demand of the campus population, but also allows for future campus growth well into the 21st century.

BIOGRAPHIES

Stephen N. Briscombe received his BS degree from the College of Engineering & Science, Leeds, England. He has broad experience in the field of power system construction, engineering, and operations. Upon graduation, he worked for 4 years on the Snowy Mountain Hydro Electric Project, New South Wales, Australia, and then 12 years with Bechtel Power Corp on nuclear power plant electrical design, construction, and start-up. Prior to joining Stanford University, Facilities Operations, Utilities Division, Mr. Briscombe designed and constructed power systems for both wind generation and resource recovery power plants. At Stanford University he is responsible for managing the electric power system. He is a member of IEEE.

Glyn Lewis received an HNC in 1964 from University of Wales Institute of Science and Technology. He is a registered professional engineer in California and a member of IEEE, Industrial Applications Society, Power Engineering Society, and Dielectrics and Electrical Insulation Society. He is an associate member of NETA. He is also a member of NFPA, an associate member of IAEI, and a senior member of ASE. He has worked as a commissioning engineer in the UK in the fields of distribution and transmission substations and large steam power plants. He spent many years with GE as a field engineer, a power system specialist, and a power system engineering supervisor.

Michael J. Thompson received his BS, Magna Cum Laude from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories in 2001, he was involved in the development of a number of numerical protective relays. He is a member of IEEE and has authored and presented several papers on power system protection topics.

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