

Designing a Special Protection System to Mitigate High Interconnection Loading Under Extreme Conditions – A Scalable Approach

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Designing a Special Protection System to Mitigate High Interconnection Loading Under Extreme Conditions – A Scalable Approach

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Abstract—In 2012, San Diego Gas & Electric (SDG&E) added a new 500 kV line, Sunrise Powerlink, to provide an additional transmission path from the Imperial Valley into the San Diego metropolitan area. This addition provided the ability to increase import power levels, enabling access to renewable generation planned for the Imperial Valley. In planning for the addition of this line, the operations group determined that, due to the increased import levels available with Sunrise Powerlink, there was a need for the addition of a special protection system (SPS) that would operate under non-credible system outage conditions. The original design goal was to develop an SPS that would respond to high loading at the SDG&E northern interconnection (referred to as Station S) and shed load on the SDG&E system. The goal was to reduce interconnection loading to prevent the operation of the overcurrent separation scheme from the neighboring utility, which would open the interconnection. The SDG&E project team met in late 2011 to discuss the design requirements for the SPS and vetted the concept of using a synchrophasor platform. SDG&E was in the process of installing a multiwinding differential relay at Station S to provide synchrophasor voltage and current inputs for the five SDG&E 230 kV lines that terminate at the interconnection so that synchrophasor data would be available for use in the SPS. Because the initial design goal was relatively concise in requiring local measurement and logic, the design team decided that the multiwinding relay would sum the analog values for the currents of the five 230 kV lines in a more conventional scheme, sending SPS outputs to another station (Station L) where the SPS controller would reside. At Station L, the SPS controller would be used to communicate with the relay at Station S and issue load-shed commands to 12 SDG&E distribution stations. The nature of the design would allow for the addition of future load-shed sites and for the future application of synchrophasor inputs if dictated by system operating requirements.

I. INTRODUCTION

This paper describes the design process for the SDG&E special protection system (SPS). In June 2012, San Diego Gas & Electric (SDG&E) added a new 500 kV line, Sunrise Powerlink, to provide an additional 500 kV transmission path from the Imperial Valley into the San Diego metropolitan area. In addition to the reliability benefits of a new 500 kV

path, this new line provided the ability to increase import power levels, enabling access to renewable generation planned for the Imperial Valley. In planning for the addition of this line, the operations group determined that, due to the increased import levels available with Sunrise Powerlink, there was a need for an SPS. The new SPS would operate under the non-credible concurrent outage of two 500 kV paths into the San Diego area.

II. SYSTEM OVERVIEW

The original design goal was to develop an SPS that would respond to high loading at the SDG&E northern 230 kV interconnection (Station S) and would operate to shed load on the SDG&E system. The goals for the SPS were to detect high interconnection power flow and operate to reduce interconnection loading to a safe level. These actions would prevent the operation of the overcurrent separation scheme from the neighboring utility, which was designed to open the interconnection under high loading conditions.

The SDG&E project team met in late 2011 to discuss the design requirements for the SPS. The team vetted the concept of using a synchrophasor-based platform for the SPS. In a synchrophasor monitoring project already under way, SDG&E was in the process of installing a multiwinding differential relay with synchrophasor outputs at the northern interconnection station. The platform was designed to provide synchrophasor voltage and current inputs for the five SDG&E 230 kV lines that terminate at the interconnection. The platform could also provide synchrophasor data from the five interconnection lines for use in the SPS, if determined necessary. Because the SDG&E synchrophasor project also included the installation of synchrophasor monitoring for all of its other interconnection points, the design team understood that a wide-area monitoring (WAM) system could be established for the SPS if dictated by system operating requirements.

Fig. 1 shows the major transmission interconnections for the area of interest.

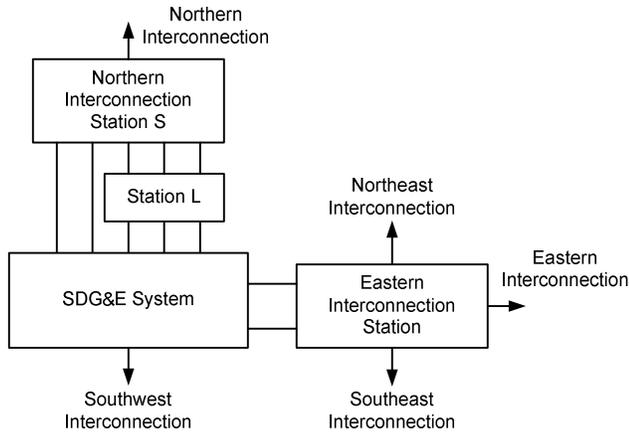


Fig. 1. Major Transmission Lines and Interconnections

Because the initial design goal was relatively concise in only requiring local measurement of the northern interconnection loading, the design team ultimately decided to use a more conventional protection scheme. There was no initial requirement (or advantage) to provide synchrophasor data for the SPS and no requirement to provide data from other interconnection points so that synchrophasor data would not be used by the SPS. Rather, the analog values for the currents of the five 230 kV interconnection lines would be summed in the multiwinding relay using mathematical equations to develop the net interconnection loading. This sum value could be compared with a set point based upon the overcurrent setting of the neighboring utility, and an output could be generated to initiate load shedding.

Fig. 2 and Fig. 3 define the results of the planning studies for the set point selection for this project [1].

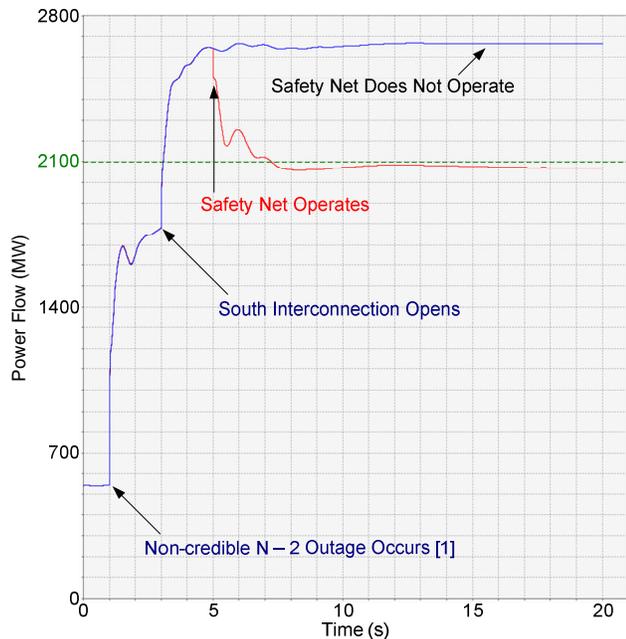


Fig. 2. Studies to Define the Set Points for the Safety Net

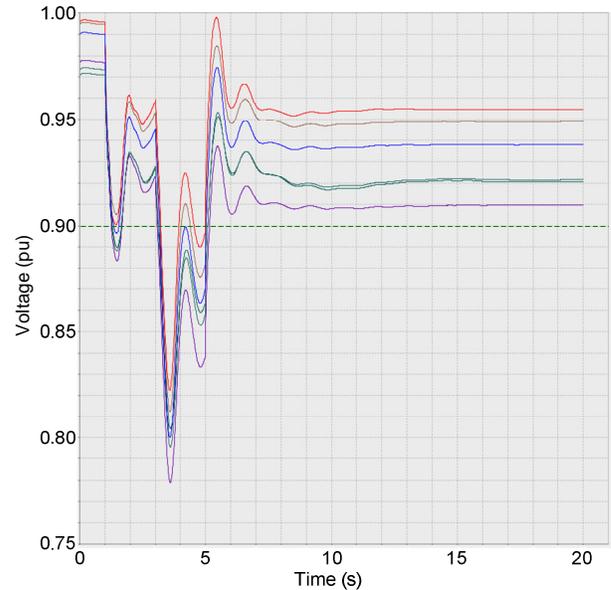


Fig. 3. SPS Voltage Recovery

While synchrophasors would not be used in the initial SPS rollout, the design team understood that future operating requirements could dictate the need for synchrophasors from other SDG&E interconnections. The initial system design platform needed to provide the flexibility to add synchrophasor outputs, programming capability, and multiple communications ports.

The operations group ran studies that determined that load shedding would be required at 12 large distribution stations, and the design team decided that stations in the northern half of the SDG&E system would be used to simplify the telecommunications requirements. These 12 stations each had existing load-shed tripping relays that were operated by underfrequency relays and manual load-shed commands. Rather than adding new load-shed tripping output systems for the new SPS, the design team decided that trip outputs from the new SPS would be used to operate the existing load-shed tripping output systems. At the load-shed stations, new teleprotection interfaces would be added to process the SPS trips received from the master system. MIRRORED BITS[®] communications was used to communicate the load-shed outputs from another transmission station (Station L) to the I/O processors at the load-shed stations.

Station S, where the multiwinding relay resides, does not provide ready communications access to the 12 load-shed sites. In addition, access to Station S can be difficult at times because of the security protocols associated with this interconnection site. The design team decided to use Station L as the location for the SPS master controller. In this way, SPS output signals would be sent from the interconnection Station S to a master SPS controller at Station L, where the signals could be processed and distributed to the load-shed sites. Because Station L has a large distribution load, local load shedding could be used to account for one of the 12 load-shed stations. The supervisory control and data acquisition (SCADA) interface at Station L would be used to provide remote control and monitoring.

The SPS controller was chosen to provide multiple communications ports to communicate with Station S and the load-shed stations, with spare capacity for future needs. The controller needed to have an advanced logic engine to handle present and future SPS requirements. The design team decided that it would be advantageous to provide local validation of high interconnection loading at Station L and to provide AND logic for this indication with the received signal from Station S. Three of the five 230 kV interconnection lines from Station S terminate at Station L, so it is possible to measure the total flows of these three lines and provide supervision for the SPS. The flows of the three lines are added in a programmable automation controller, and outputs are provided to the SPS controller. In this way, local validation of high interconnection loading is provided to validate the received signal from Station S, providing additional security from false operation.

In early 2012, with the SPS design well under way, a large nuclear generating unit tripped at the northern interconnection station while the second unit was out of service for refueling. As the investigation into the trip was initiated, it became apparent that the operation of the transmission system without either of the two large units would have to be studied. Without these two units, transmission system voltage control would be a challenge, especially under extreme interconnection loading conditions. Operating studies indicated that additional logic was needed in the SPS to address system operation under lower interconnection loading levels than originally contemplated. The SPS design team was asked to provide additional logic to handle three different interconnection loading levels, with three subgroups in each level, for a total of nine new scenarios. When added to the initial SPS design goal, the team was now designing for ten different scenarios, which were referred to as setting groups. Each setting group would be selectable by SCADA control and would operate to provide load-shed outputs at different interconnection loading levels. The flexibility of the SPS controller allowed for the seamless addition of this logic.

As previously mentioned, remote control and monitoring are provided through the SCADA system at Station L. The SPS is enabled or disabled via the remote terminal unit (RTU) at Station L, and the setting group is also chosen through the RTU. After the setting group is selected at Station L, a MIRRORED BITS communications message is sent to Station S, where the chosen setting group is enabled. A MIRRORED BITS communications message is sent from Station S to Station L, confirming the active setting group. At Station L, a disagreement alarm is sent to the control center via SCADA if the received setting group from Station S does not match the chosen setting group.

After the full implementation of this logic in the SPS, the system operations group decided that ten setting groups provided too much complexity for the transmission system operators and decided that a reduction to four setting groups was needed. The SPS design team agreed that reducing the number of setting groups would provide a simpler operation and revised the SPS design to reduce the number of setting

groups to four. The setting groups based upon the lower interconnection loading levels were labeled Setting Group 1, Setting Group 2, and Setting Group 3. The setting group based upon the availability of the nuclear units was Setting Group 4.

The output timing budget was another important design consideration. Based upon the operation planning studies, for operation under Setting Groups 1 through 3, the SPS outputs were required to operate within 1 second of abnormal interconnection loading. However, the design team needed to ensure that the SPS would not operate for a fault event on the transmission system, so the SPS could not be allowed to operate instantaneously. The design team decided to use a 600-millisecond delay to ensure non-operation of the SPS for Zone 2 fault events. In addition, the design team employed logic to require a power factor greater than 0.9 to ensure that the SPS would only operate for load events on the transmission system. The power factor was near unity during the studied events.

The original SPS was referred to as a Safety Net because its design was based upon non-credible system conditions. Safety Net designs do not typically require a redundant approach. During the SPS design process, operating discussions determined that a redundant design was required even though the system was still classified as a Safety Net. The SPS design team had to quickly react by moving to a redundant System A and System B approach, essentially doubling the hardware and communications requirements while the project was under way. One additional design element was added. Because the System A and System B setting groups were designed to be set independently by the transmission system operator, logic was provided to compare the active setting groups of the two systems. A disagreement alarm will activate if the active setting groups are not the same.

III. WIDE-AREA MONITORING AND SYNCHROPHASORS

A. *Synchrophasors*

Synchrophasors are widely used today to monitor the state of the power system. In the near future, it is anticipated that synchrophasors will be used for various control applications if wide-area synchronized system information is available. SDG&E is an active member of the Western Electricity Coordinating Council (WECC) Western Interconnection Synchrophasor Program (WISP) and has more than 80 phasor measurement units (PMUs) in service. SDG&E is already working on various applications using transmission and distribution synchrophasor measurements.

IEEE C37.118-2005 and IEEE C37.118-2012 define synchronized phasor measurements as well as the message format for communicating these data in a real-time system. While most people think of these standards with regard to sending time-coherent voltage and current phasors, IEEE C37.118 messages can be used to provide much more information (such as additional analog data, digital status information, and control signals) as part of the synchrophasor packet.

A phasor represents a voltage or current of an ac system that operates in a steady state. Fig. 4 shows an example of a sinusoidal voltage function called $v(t)$, with a period of T seconds where the RMS value $A/\sqrt{2}$ and Φ correspond to the magnitude and angle of the phasor that represents this voltage signal.

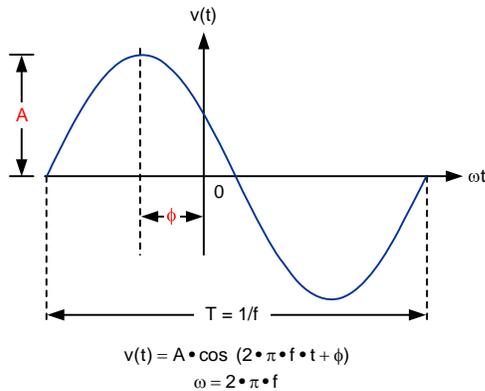


Fig. 4. Synchrophasor Measurements in a Wide-Area Power System

B. Wide-Area Monitoring and Applications

Synchronized measurements of voltage phasors, current phasors, and frequency are key to power system analysis. The Coordinated Universal Time (UTC) reference and the synchronized voltage signal provide a snapshot across the power system, as illustrated in Fig. 5.

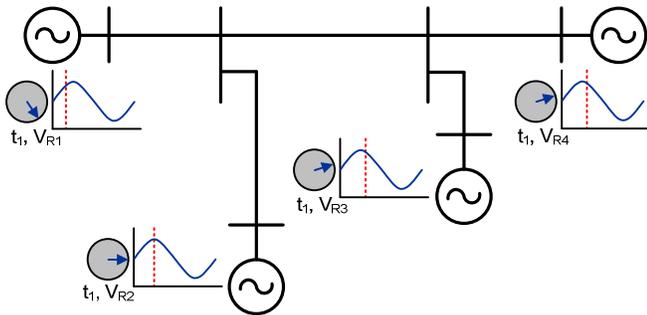


Fig. 5. Wide-Area Synchronized System

Some synchrophasor applications include the following [2]:

- State measurement
- Real-time monitoring (V , I , P , Q , and f)
- Power system model validation
- Situational awareness
- System restoration
- Stability analysis
- Event analysis

Traditional information management systems and protocols (e.g., DNP3, Modbus[®], and OPC) that are used to communicate information back to a central location only send magnitude measurements. These systems update information every few seconds to every few minutes. Additionally, the data are not time-coherent or time-stamped, making it difficult to accurately assess system conditions. Using synchronized measurements helps overcome these shortcomings and

provides many additional benefits. One possible application is to use PMU synchrophasor measurements for dynamic model verification [3]. Many utilities archive years of PMU data, and such gathered information that can be applied for wide-area system dynamic response validation and analysis. For any switching operation, a PMU-measured system response can be validated against the dynamic system model used by a planning department. PMUs can also be applied to evaluate the generator control actions and system dynamic response. This helps to validate the dynamic models of exciters and governors for various system disturbances.

Synchrophasors can also help monitor system oscillations and damping factors for small signal analysis generated from distributed generation (e.g., wind and solar). It is anticipated that by 2020, 33 percent of all the energy provided to customers in California will be delivered from renewable energy resources [4]. More and more renewable energy sources mean less rotating mass. The grids are designed to have a lot of inertia, which allows the system to absorb and recover from disturbances. Hence, for future grid operation where a high penetration of variable generation sources is integrated in the grid, synchrophasor data will be a very important tool for wide-area monitoring and control.

C. Future SPS Solution

As noted at the outset, the SPS was designed with the understanding that future SPS operating requirements could dictate the need for synchrophasors from other SDG&E interconnections. By providing PMU data streams from the existing communications channels from Station S and adding new PMU data streams from the eastern and southwest interconnection stations to the SPS controllers at Station L, a WAM platform could be provided (see Fig. 6). The present design is only based upon the five line current measurements at Station S. In the future, synchrophasors from remote stations will help determine the present system state and provide situational awareness.

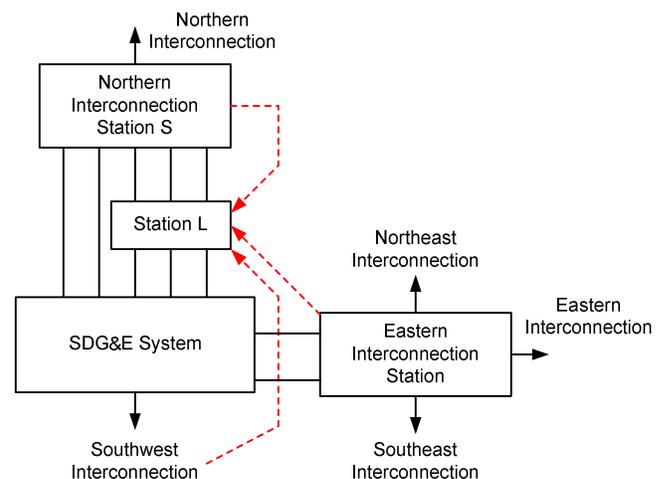


Fig. 6. Additional PMU Inputs to SPS Controllers at Station L

With a WAM platform in place, it would be possible to develop advanced algorithms to compare voltage magnitudes and phase angles at all of the interconnection points. This could provide additional flexibility for handling diverse operating scenarios that deal with varied system configurations and generation dispatches. The resulting wide-area protection and control system could provide additional logic and additional control outputs to initiate action at the other interconnection stations.

IV. DESIGN DISCUSSION

A. Overload Protection and Logic

The overall scheme includes protection logic at Station S, automation logic at Station L, and load sheds at various locations, including the local load sheds at Station L. Based upon the remote SCADA setting group selection, information for the selected setting group is communicated to Station S. If both System A and System B are in service and no setting group error is observed, then the overall scheme will be placed in service [5][6][7].

The overall scheme design, shown in Fig. 7, requires the design to be flexible to accommodate the design changes required for this project. The final design includes four setting groups; three of these groups include instantaneous overcurrent elements. The fourth group has both instantaneous and time overcurrent elements. The instantaneous overcurrent and time-overcurrent pickup selection is shown later in Table I. Fig. 8 shows the overcurrent coordination of the upstream CO6 overcurrent relay with the Safety Net-selected time-overcurrent relay U5 curve. The upstream overload CO6 relay was programmed at 8,000 A with a time dial of 8.7. The new multiwinding relay was selected to provide adequate margin with a pickup setting of 7,200 A and with a time dial of 8. For this scheme, the relay was required to operate from 7,200 to 8,400 A using the time overcurrent element. For currents greater than 8400 A, the instantaneous element operates to activate the trip outputs.

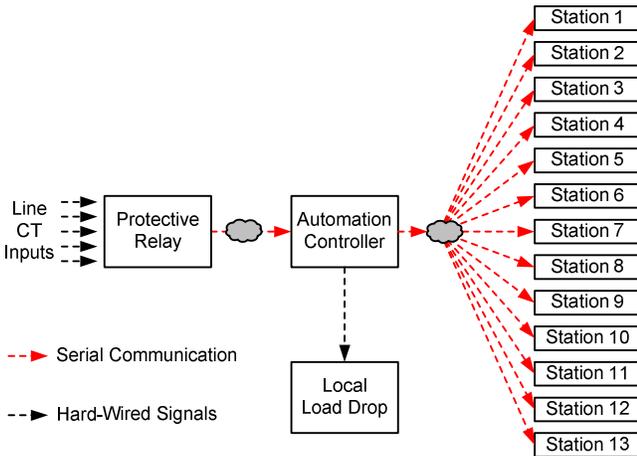


Fig. 7. SPS Includes Protective Relay and Automation Controller

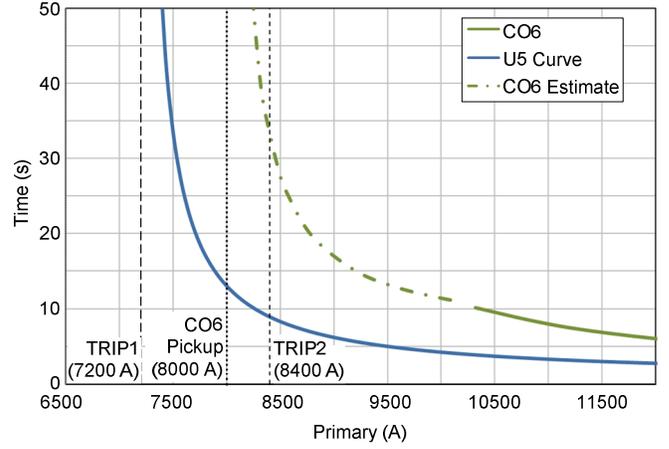


Fig. 8. Overcurrent Coordination of the Safety Net Relay

B. Time-Overcurrent Custom Logic

The existing synchrophasor relay connections provided synchrophasor data from the five lines. This relay is coordinated with the existing upstream electromechanical CO6 relay. For time-overcurrent logic, the instantaneous parts of real (I_r) and imaginary (I_m) overcurrent from the five incoming lines were added per phase for the power factor 0.9 or above. The total current T is the vector sum of I_r and I_m . Because the overcurrent relay replicates the overload protection, the logic ignores the currents for fault conditions.

$$I_a(r) = (I_{r1} + I_{r2} + I_{r3} + I_{r4} + I_{r5}) \text{ and PF} > 0.9 \quad (1)$$

$$I_a(m) = (I_{m1} + I_{m2} + I_{m3} + I_{m4} + I_{m5}) \text{ and PF} > 0.9 \quad (2)$$

$$I_a(T) = \sqrt{[I_a(r)]^2 + [I_a(m)]^2} \quad (3)$$

Fig. 9 shows the distance traveled by an electromechanical relay. The total distance traveled by the disk equals 1 when the starting point is zero. The disk will start moving forward when the current is above the pickup, and the disk will start to move backward once the current is below the pickup. This integration logic was implemented in the custom logic of the protective relay.

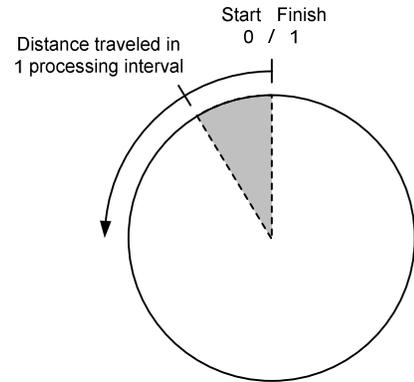


Fig. 9. Disk Distance Traveled by Electromechanical Relay

Equation (6) defines the total distance traveled for each processing interval. The selected relay processes the protection logic eight times per cycle. Hence, for the 60 Hz system, the processing frequency is $60 \cdot 8 = 480$ Hz [8].

Equations (4), (5), and (6) can also be applied to calculate the disk position for the backward movement. Hence, for each processing interval using these equations, the time-overcurrent relays can be programmed to replicate the disk movement. For this application, the disk movement was verified for various normal and abnormal system operation conditions.

$$\text{Disk forward speed (DFS)} = \frac{\text{Total distance (TD)}}{\text{Operation time (OT)}} \quad (4)$$

$$\text{Processing interval time (PIT)} = \frac{1}{\text{Processing frequency}} \quad (5)$$

$$\text{Distance traveled (DT)} = \text{DFS} \cdot \text{PIT} \quad (6)$$

C. Protection Logic Details

At the inception of the SPS project, SDG&E was already working on a transmission synchrophasor project at Station S. The relay selected for the synchrophasor project was used in the SPS. The protective relay at Station S receives the setting group selection via the controller at Station L. Subsequently, the protective relay at Station S will select the correct setting group and will provide this confirmation to the remote-end automation controller at Station L. The scheme is only enabled if the setting group confirmation is received from Station S and the setting groups match at both stations. For the Safety Net project, System A and System B are designed based upon identical protection logic. Redundant communications routes are used.

The setting groups, trips (load sheds), and set points are shown in Table I. Four setting groups were selected for this scheme based upon the planning studies, as discussed in Section II. A total of 14 load sheds are programmed, with 13 remote load-shed stations and 1 local load shed at Station L. For Setting Group 1, two set points are selected. When Setting Group 1 is selected and the total loading on the five lines is above Set Point 1, the scheme will instantaneously shed the loads at Stations 1 through 7. If the load reaches above Set Point 2, the scheme will shed loads at Stations 8 through 14. The same logic is applicable for Setting Groups 1 through 3. For Setting Group 4, the time-overcurrent relay trip is replicated for Set Point 1. Instantaneous overcurrent trip is enabled for Set Point 2. Trip 1 will sequentially shed loads at Stations 1 through 14 in 0.5-second intervals if the loading is above the pickup. Trip 2 will shed Stations 1 through 7 in 0.5 seconds and Stations 8 through 14 in 1 second. All of the instantaneous overcurrent pickups are delayed to coordinate with the Zone 2 delays of the distance elements to avoid pickup for line faults. Protection logic is processed eight times per cycle. Instantaneous overcurrent is the summation of the five lines, and the total current is selected as the operating quantity for this scheme. To account for the different line current angles, real and imaginary quantities of line currents are added separately. Subsequently, relay testing is performed at different power factors and line loading; the results are then verified for the total current measurement by the relay. Protection logic is scalable to easily accommodate additional

setting group and set point changes based upon future study and design requirements.

TABLE I
SETTING GROUPS AND CORRESPONDING ACTIONS

Group	Trip 1	Trip 2	Description
SG1	4016A	5146A	Trip 1: Inst Trip Load Stations 1–7 Trip 2: Inst Trip Load Stations 8–14
SG2	5522A	6652A	Trip 1: Inst Trip Load Stations 1–7 Trip 2: Inst Trip Load Stations 8–14
SG3	6025A	7154A	Trip 1: Inst Trip Load Stations 1–7 Trip 2: Inst Trip Load Stations 8–14
SG4	7200A	8400A	Trip 1: TOC Trip Load Stations 1–14 Trip 2: Inst Trip Load Stations 1–7 at 0.5 s, Trip Load Stations 8–14 at 1.0 s

Inst = Instantaneous

SG = Setting group

TOC = Time-overcurrent

D. Automation Logic Details

Two automation controllers (Automation Controller A and Automation Controller B) were selected for the Safety Net SPS. The two automation controllers have identical programming, operate in parallel, and act as backup for each other. The only difference between System A and System B is that System B has dual communications channels and automatically switches the channel if one channel fails. The Safety Net automation scheme continuously monitors all of the communications links between Station S, Station L, and all the load-shed stations. The two alarms programmed for this scheme are shown in Fig. 10. The scheme also compares the setting group selection of System A and System B, and an alarm is generated if a discrepancy is observed. If a discrepancy in the setting group between Station S and Station L is observed, then the Safety Net scheme is blocked and a command is sent to the SCADA RTU.

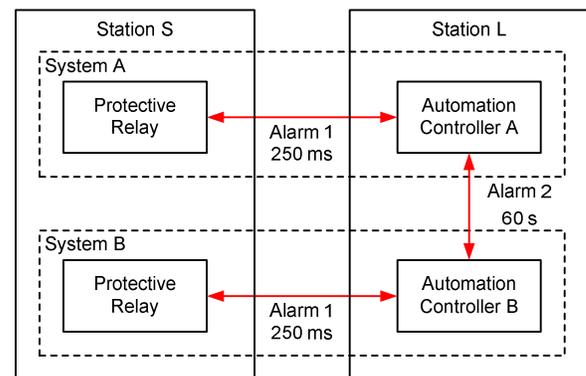


Fig. 10. Mismatch Alarm Logic Details

Detailed testing was performed to verify the design and load-shed operation and sequence. Like the protection scheme, the automation scheme design is also scalable and can accommodate additional setting groups, load sheds, and design changes with minimal effort and testing. As an additional security measure, local measurement at Station L

was also added. The trip command will not be enabled unless the local permissive cutout switch is asserted (see Fig. 11).

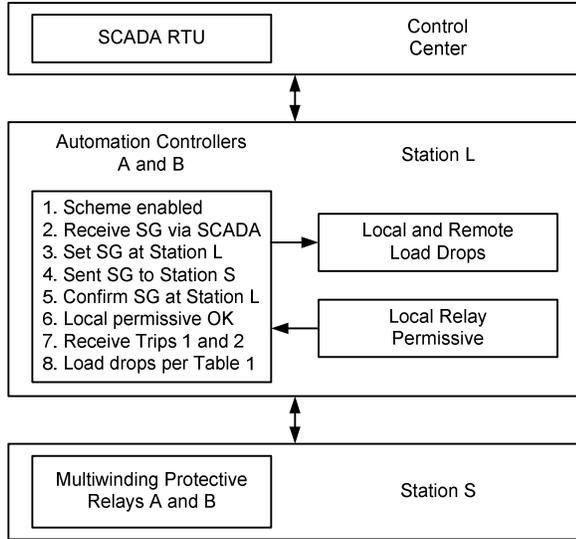


Fig. 11. Automation Logic Details

E. Design Verification and Test

Detailed design verification and testing was performed at the system integrator's factory to verify the correct operation of the scheme [9]. From the Global Positioning System (GPS) clock, IRIG-B input is provided to both the protective relays and the automation controllers. This provides GPS time synchronization for both System A and System B with millisecond time accuracy. This testing allows for the correct determination of sequence-of-events operations for the Safety Net scheme and correlates this scheme operation with system events.

For in-service testing, manual triggering of the event report can help review and verify all of the analog quantities, total flow, and digital relay bits. All of the relevant logic bits are mapped in the event report to provide easy event analysis and troubleshooting. The protective relay also monitors the total current that can be used to determine the total power flow monitored by this scheme. Additionally, a test mode is provided in the Safety Net scheme via the protective relay. While in this mode, the scheme can be tested for all the logic and for closed-loop communication. Aliases are used as applicable to simplify the logic and troubleshooting.

The front-panel target light-emitting diodes (LEDs) and display points on the protective relay provide an overview of the Safety Net scheme. The information provided includes the selected Safety Net setting group, system voltage, line power flow on each of five lines, total Safety Net power flow, any trips, and so on. The display points replicate the three single-phase time-overcurrent measurements, pickup, present disk position, and estimated operation time. For the automation controller, customized front-panel LEDs are programmed to indicate the schemes that are in and/or out of service, the selected setting groups, and trips. Sequential Events Recorders (SERs) in the automation controller are used to record all of the important variables and communications parameters for future analysis. Some important system operating variables are

also mapped to the SCADA system to permit centralized system monitoring. The event analysis will accurately determine the total interconnection loading, load increase, scheme setting group, and operational details. When the Safety Net scheme is in service and an appropriate trip command is initiated, the automation controller will start shedding the loads based upon a predetermined sequence. If the total load on the system (as determined by the Safety Net scheme) sheds during this process, the trip command from the protective relay will automatically reset and the automation controller will immediately stop shedding loads and reset the load-shed sequence.

In order to reduce the time spent during on-site verification, in-depth design and logic verification was performed during factory acceptance testing (FAT). Because four setting groups (each with two levels of trips) are programmed for the Safety Net design, the operation for all four setting groups was verified for the Trip 1 and Trip 2 set points and the associated logic during the detailed design verification. Fig. 12 shows the system setup used for the FAT. In order to test a total of five line currents, Line 4 and Line 5 used the same current as Line 1 and Line 2, respectively, because the available test set allowed varying only three line currents and angles at a time. This setup provided adequate system conditions to verify the logic designed for this scheme. In addition, the automation controller, communications paths, and SCADA RTU were also included in the setup and were programmed to replicate the actual system conditions.

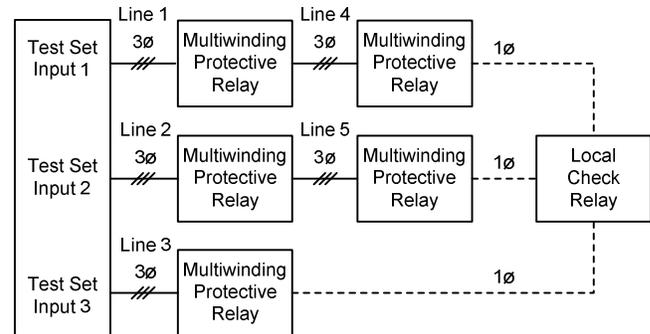


Fig. 12. FAT Setup for Five Line Currents

The selected protective relay is capable of adding the two line currents internally. Hence, the first test was the verification of the custom protection metering calculation logic for the summation of two line currents. This logic was compared with the internal protective relay current measurement and hand calculation. The two-line current logic in the protective relay was also tested for various system conditions, such as current increase, subsequent current, and power factor variations. The logic was also verified for five line currents and different power factors on different lines. The first three setting groups in the Safety Net scheme operate on instantaneous overcurrent only. In addition to pickup variation for the three groups, logic verification, relay front-panel LEDs, and display points at Station S were also verified. Subsequently, the trip information was verified in the automation controller and the SCADA RTU at Station L.

Correct operation of load sheds and the load-shed sequence of operation was also verified during the FAT. The logic was also verified for various abnormal system conditions, such as loss of communication between Station S and Station L, between the automation controller and load sheds, and between System A and System B. For the Safety Net Setting Group 4, which is programmed for the time-overcurrent curve as Level 1 and instantaneous overcurrent as Level 2, the logic was validated for both of the levels. During Level 1 operation, it was verified that the operation time of the Safety Net scheme coordinates with the upstream CO6 overcurrent curve. Refer to Fig. 8 for the comparison of results.

Fig. 13 shows an example of an event report during the load increase, which was monitored by the Safety Net protective relay. The protective relay is capable of recording the total current flow as an analog quantity in the event report. In this example, the relay recorded a current increase from 2,000 A to 5,160 A. As the current increased above the pickup setting, appropriate variables were asserted. If the overload condition persisted, per the scheme design, a trip would be issued after 0.6 seconds.

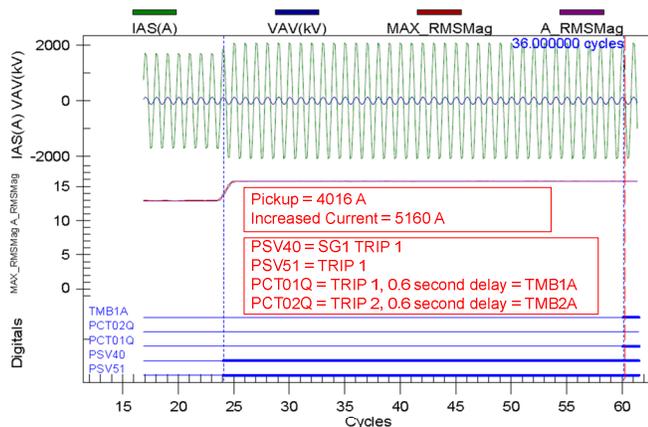


Fig. 13. Event Analysis Example

V. CONCLUSION

SPSs are critical for electrical grid operation and require careful design, documentation, and testing. Scalable design, ease of system operation, accessible front-panel information, system monitoring, and event analysis were some of the additional design goals for this critical project. The present scheme is scalable and accommodates design changes with minimum effort. It is also easily upgradable to a synchrophasor-based WAM system and SPS. This scheme, which has been in service since June 2012, has been updated once using the scalable design. With the high penetration of variable generation in the grid, synchrophasors are critical for wide-area system monitoring and control. The present design can easily accommodate synchrophasor inputs to provide a WAM system.

VI. ACKNOWLEDGMENT

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