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Lessons Learned in Implementing Modular Integrated Substation Control Buildings at Pacific Gas and Electric Company

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Abstract **- Pacific Gas & Electric Company has a system wide program for applying Modular Protection Automation and Control (MPAC) buildings. PG&E began installing MPAC control buildings in 2004 and is now in full system wide deployment, installing approximately 10-15 MPAC buildings per year.**

This paper covers some of the lessons learned, and mid-stream adjustments that had to be made to PG&E's MPAC program. In particular, the challenges in migrating from a conventional non-integrated design to a relay logic intensive design and how this affected test processes and procedures.

Issues discussed within the paper include:

- **Brief overview of PG&E MPAC program.**
- **Establishment and definition of Factory Acceptance Test (FAT) and Site Acceptance Test (SAT) procedures.**
- **Functional testing of relay logic instead of line by line logic verification.**
- **Standard fault files provided by Protection Engineer for settings verification and also for verification of logic and LED targets.**
- **Need for standard relay logic diagrams and combined multi-relay logic diagrams to illustrate complex schemes and relay to relay messaging.**
- **Affects of DC Transients and adjustments to relay contact input debounce timer settings and relay logic.**
- **Challenges with Set A and Set B relay platform. Pulsed relay outputs vs. latched outputs.**
- **Operational Issues – Standard HMI Screens – Establishing alarm hierarchy and annunciator screens.**
- **Training Issues – Establishment of MPAC Simulator for Operator and Technician training.**

I. BACKGROUND

Pacific Gas and Electric Company (PG&E) is one of the largest combination electric and gas utilities in the United States. It serves about 15 million customers in northern and central California. Approximately 20,000 employees serve its 70,000 square mile territory. It is a vertically integrated utility with Generation, Transmission and Distribution assets. Its transmission system is made up of approximately 18,610 miles of 500, 230, 115, 70 and 60 kV lines.

II. INTRODUCTION

Protective relays have evolved greatly over the years. Today's microprocessor relays have the capability of Programmable Logic Controllers. Relays are now being programmed to perform multiple relay functions and include complex logic for performing protection, automation and control functions. Additionally some relays now include user programmable pushbuttons, LEDs, and display screens, thus eliminating the need for external switches, control handles, meters, indicating lights and annunciators.

Fig. 1. MPAC building being offloaded at substation

By using all of these capabilities, today's relays can provide full substation integration and automation. Wires and discrete devices are replaced by complex relay logic. With the creation of the complex relay logic arises the challenge with how to modify existing test processes and procedures to accommodate this change in technology. How do you test and prove the relay logic? How do you manage setting changes after logic has been proven? Today's relays can contain thousands of settings, what can be done to prevent or catch setting errors? This paper addresses how PG&E handled these issues and other lessons learned in applying Modular Protection Automation and Control (MPAC) buildings.

MPAC projects at PG&E were initially implemented on an individual basis without guidelines for the overall program oversight. Later processes were developed to streamline the planning, scoping, engineering and construction phases and implement a continuous improvement process. This paper discusses some of these improvements.

III. INTEGRATED PROTECTION AND CONTROL

PG&E started development of Integrated Protection and Control (IPAC) standards in 2002 and first applied them in 2003. These standards were developed to maximize the use of existing technology to combine multiple relay and control functions into a two relay Set "A" and Set "B" relay platform. The IPAC standard was developed for application as a stand-alone single-terminal replacement for existing substation retrofits, and also for application in new pre-built Modular

Protection and Control (MPAC) buildings with HMI computer. PG&E's first MPAC building was operational in 2004. PG&E's MPAC program was developed to:

- Replace aging substation control room assets by installing modular control buildings.
- Automate PG&E substations to maximize remote control capability, on-line monitoring and diagnostics.
- Maximize use of available technology to consolidate multiple protection, automation and control functions for a cleaner more compact design that eliminates control switches, meters, and auxiliary relays and reduces costs.
- Standardize design and construct control buildings totally off site in an assembly line fashion to gain cost efficiencies.
- Deliver MPAC buildings to site fully tested and ready to go.

Approximately 10 to 15 MPAC buildings are now being installed per year. Some of these projects are being initiated by the need to automate the substation, while others are being driven by substation capacity additions and/or major bus reconfigurations such as converting a bus from single-bus configuration to ring bus or breaker-and-a-half design.

MPAC buildings are typically installed at large substations with multiple transmission voltage levels. Each voltage level usually has a separate building, and for large busses a building is installed for each bus section. The intent is to locate the MPAC building close to its respective bus section to minimize the length of trench and conduit runs to outdoor equipment.

The MPAC building is designed with an intertie cabinet with multiple termination blocks that interconnect the MPAC building with the outdoor equipment. This provides a clean demarcation between interior building wiring and circuits from outdoor equipment that are connected after the building is delivered to the substation. Testing of building systems is usually done from the intertie cabinet to the relays. The relay panels contain FT switches for testing and isolation of each relay.

Set "A" and Set "B" relays provide redundant protection functions however automation and control functions were divided between the two relays with Set "A" providing the manual operator pushbutton control interface and automatic reclosing and Set "B" serving as the primary gateway for SCADA and HMI control. This provides redundancy and a means to control the breaker if either relay platform fails. This configuration also allows the integrated design to be applied as stand alone panels in existing substation retrofit jobs where an HMI computer may not exist.

Set "A" and Set "B" relays were also selected from different relay manufacturers to follow PG&E protection philosophy. This is to avoid common mode failures and for diversity. Having different relay manufacturers greatly complicated the integrated relay scheme design. This was part of the reason for the division of automation and control functions between the two relays.

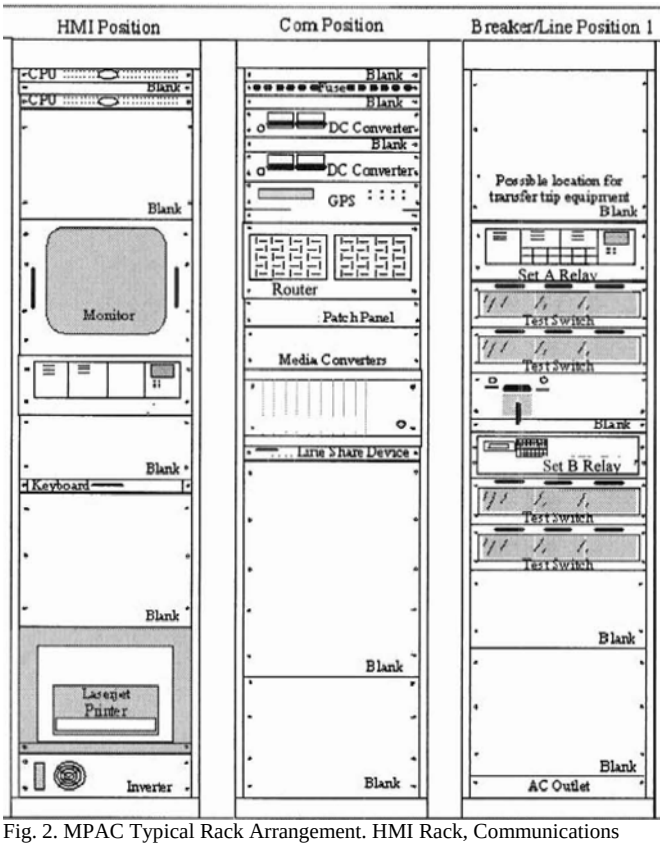

Fig. 2. MPAC Typical Rack Arrangement. HMI Rack, Communications Rack, and Breaker/ Line Rack shown (left to right).

Fig. 3. HMI panel for Newark 115kV Bus F MPAC building.

IV. MPAC Testing Sequence

PG&E management initially envisioned all MPAC functional testing of automation and protective schemes would be done by the building fabricator, prior to shipping the MPAC building to PG&E. A plug-and-play concept was envisioned where minimal on-site testing would be performed, and only commissioning tests would be performed on-site by PG&E relay technicians. This did not prove to be a workable solution for a number of reasons, the main ones being:

1. Vendor lack of expertise of PG&E relay schemes. This had a two fold impact.
   a) Test procedures may be misunderstood and/or performed improperly.
   b) When a test fails, trouble-shooting relay logic is difficult at best without detailed knowledge of relay schemes.
2. Ultimate responsibility for proper scheme operation resides with PG&E. This resulted in detailed on-site testing which was redundant to the intended testing by the MPAC fabricator.

MPAC scheme testing quickly evolved into two distinct phases. Those tests performed by the MPAC building fabricator at the factory, called Factory Acceptance Testing *(FAT)*, and those performed by PG&E after the building was delivered to site, called Site Acceptance Testing *(SAT)*. Following the SAT, existing PG&E commissioning test procedures are then used to test, connect, and energize the indoor equipment to the outdoor equipment.

Separate from the protection and automation scheme testing, a Building Acceptance Test *(BAT)* procedure was also developed to verify the MPAC building's physical status and building systems (lights, HVAC, etc.) after delivery to the site.

A. Factory Acceptance Test (FAT)

The first phase of the MPAC testing sequence is the Factory Acceptance Testing. The intent of the FAT is to verify all MPAC building systems and wiring are functional. Final protection and automation device settings are loaded at the FAT. Basic metering, status and control functions are verified from the relays and HMI computer. Secondary current and potential is injected into the relays from the intertie cabinet to prove the metering. Breaker simulators are connected at the intertie cabinet during FAT testing to simulate breaker operation and provide 52a status. To simplify testing, no fault simulation or detailed protection scheme testing is done. FAT test procedures have been developed to test and verify the following:

- Point-to-Point Wire Checks
- SCADA/HMI Database, Screens, Status, Metering and Control Functions
- Relay Settings Properly Loaded
- Device DNP/IP Addresses Set and Inter-Device Communication Functioning Properly
- Manual Relay Pushbutton Controls and Metering
- AC Current and Potential Wiring from the Intertie Cabinet to the Discrete Components
- Breaker Operation and Status (using breaker simulator)
- Relay Trip Outputs Operate Breaker Simulator
- External Equipment Trip Inputs (Transformer Mechanical Devices - Sudden Pressure Relays, etc.)
- Alarm Annunciation

It should be noted that providing final protection settings for the FAT testing required relay settings to be provided by the protection engineer several months earlier. This was a big adjustment for the protection engineers at PG&E.

Upon completion, FAT test results are electronically sent to PG&E for review and approval prior to shipping the MPAC building.

Fig. 4. MPAC Building Indoor/Outdoor Intertie Cabinet (doors removed during FAT)

Fig. 5. Breaker simulator connected at intertie cabinet during Factory Acceptance Testing.

B. Building Acceptance Test (BAT)

Procedures have been developed to verify the MPAC building's status after delivery to the site, and acceptance requirements for tasks performed by the building supplier after delivery. This includes the following:

- Any Physical Damage during Transportation (External and Internal)
- Securing to Foundation and Grounding Requirements
- Outdoor Cable Riser Connection to Building and Cable Trench
- Rack and Cabinet Wiring Inspection
- Connecting AC and DC Sources
- Energizing Racks and Equipment
- Operation of Fire Systems
- Functionality of GPS Clock and Antenna
- Visual Inspection of the Building Batteries (if included) and Bracing

C. Site Acceptance Test (SAT)

Site Acceptance Testing is performed after the MPAC building is delivered to site and AC and DC sources have been supplied to the building. This is typically two weeks after building delivery. PG&E Operation Data Network (ODN) is also connected to MPAC building to enable testing of SCADA to the remote Master Station (Control Center). The intent of the SAT testing is to have the entire building tested prior to connecting to the outdoor equipment. Detailed test procedures have been developed to test and verify operation to the intertie cabinet terminal connections. Breaker simulators are connected at the intertie cabinet during SAT testing to simulate breaker operation and provide 52a status.

Traditionally, when testing relays temporary setting changes were performed to accommodate testing practices. The philosophy with the MPAC and IPAC relays is to perform testing without making changes to the settings. The reason for this change is to verify the final protection and logic settings function as intended. When testing is completed the settings are then in a proven state and the relay is ready to be put into service with full confidence.

Internal relay logic settings and intermediate logic test points are not checked during SAT testing. Rather, the relay logic is proven by overall scheme testing. Each relay function is tested by applying external conditions to the relay and verifying that the desired relay action occurs. For relay functions that are supervised by permissive elements, such as a feature enable pushbutton or a lockout input, the function of the relay is verified with each permissive condition in an asserted and then deasserted state.

SAT testing has been developed to reduce redundant testing of relay logic I/O and protection functions. For example, if you are testing the relay trip output contact, a fault is applied to the relay to operate a specific output contact and all other trip output contacts are isolated via isolation FT switches. If you are verifying the operation of the BF re-trip output contact a different type of fault is applied to the relay and only the BF re-trip output contact is verified.

SAT testing consists of the following:

- Local HMI and Master Station (Operating Control Center) operations of SCADA/HMI Database, Screens, Status, Metering and Control Functions
- Device DNP/IP Addresses and Inter-Device Communications
- AC Current and Potential wiring from the termination cabinet to the discrete components
- Manual Pushbutton Controls and Metering
- Relay Logic – overall scheme and logic verification rather than line by line verification
- Relay Settings – through state simulated system fault injections.
- Breaker Operation and Status (using breaker simulator)
- External Equipment Trip Inputs (Transformer Mechanical Devices - Sudden Pressure Relays, etc.)
- Alarm Annunciation

A SAT test document is provided for every relay panel in the MPAC building for testing consistency. This includes non-integrated relay panels for special protection schemes or RAS (Remedial Action Scheme).

C. Commissioning Tests

Existing commissioning test requirements are used to test, connect, and energize the indoor equipment to the outdoor equipment. Traditional commissioning test procedures are still valid for use with integrated schemes. They consist of the following:

- Current Transformer Testing – Includes CT saturation, polarity, voltage ratio testing, and secondary injection at the CT cabinets to the discrete devices.
- AC potential connections to discrete devices
- Breaker Operation and Status
- Operation of External Equipment Trip Inputs
- Load Checks (In-Service Tests)
- Satellite end-to-end testing for pilot relaying schemes

V. Routine Relay Maintenance

The maintenance of integrated and MPAC protective relaying schemes utilize the SAT procedures along with the state simulated faults provided by the protection engineer for the specific scheme design.

VI. Relay Setting Change Management

The intent of the SAT testing is to functionally prove as-left relay logic and settings function as intended. For some relays there is more than 500 lines of logic used. During the SAT and after SAT testing has been completed, if any relay setting changes are needed it is highly discouraged to download a revised setting file into the relay. Rather it is recommended to have the relay technician perform the requested setting changes directly to the relay and then retrieve the as-left settings for saving to the relay setting database.

If complex setting changes are required and a revised setting file is to be reloaded extreme caution must be taken. Errors in the relay logic and automation settings that were

corrected during the SAT can be reintroduced if the setting file the protection engineer has on record is not up to date. To avoid this it is recommended to first retrieve the in-service relay settings and compare through software those with the file saved in the protection engineer relay database. Any discrepancies should be resolved before issuing a revised setting file. After the new setting file is loaded a software compare function should also be done with the settings on the relay to make sure the file loaded properly with no errors. Following logic setting changes it is also recommended to functionally test the portions of the logic that were modified.

VII. MPAC Fault Files

For integrated protection and control schemes, PG&E test procedures were developed to functionally test the relay logic as previously described. The amount of settings and logic applied in integrated relay schemes is just too large to rely on the relay settings being perfect as issued by the protection engineer. This proved adequate for verifying the relay logic; however the test procedures as initially implemented would not identify errors in the protection settings, such as relay pickup or zone reach. This was due to how the fault test values were being calculated.

At PG&E relay test fault values were traditionally calculated by the relay technician based on the reach setting of the relay in secondary ohms. This was done using simple hand calculations or a spreadsheet that was setup to calculate the values. This approach successfully verified that the relay functioned as set, regardless of whether the relay was set correctly or incorrectly by the protection engineer. To illustrate this, following are some types of relay setting errors that could not be caught with traditional PG&E fault testing methods. These types of errors have led to relay misoperations in the past:

1. Relay set in primary ohms or amps and setting entered as secondary quantity (Some early vintage microprocessor relays required settings in primary values).
2. Relay set in secondary ohms or amps and setting entered as primary quantity.
3. Relay pickup set in per unit and setting entered in secondary amps.
4. Relay element set non-directional when it should be directional.
5. Torque control setting incorrect.
6. Non-directional instantaneous enabled when it should be disabled (reverse fault current > forward fault current).
7. Decimal error (e.g., 5 instead of 0.5) or typo, although these are much less common.

Within the first year after rolling out projects with integrated protection and control, a couple relay misoperations occurred that would fall into one of the categories above. PG&E needed to assess how to prevent these setting errors.

The exposure for making relay setting errors increased with the rollout of IPAC and MPAC projects. This was due to the huge increase in the amount of settings required for each relay. Early vintage microprocessor relays had one or two pages of relay settings, typically less than 100 settings. Second generation microprocessor relays increased the number of settings to a few hundred. Today's microprocessor relays can have literally thousands of settings.

At PG&E the traditional approach to minimizing relay setting errors was for protection engineers to check each others work, called check and review. This approach was never implemented 100% due to resources and it wasn't 100% effective. While check and review is valuable, especially when mentoring less experienced engineers, it is not practical to review a relay setting printout line by line that may be 30 to 100 pages long. Today's check and review is usually limited to evaluating the conceptual approach to how the relay was set, reviewing setting calculations, fault study cases and contingencies considered, not reviewing the setting files page by page.

Instead of putting more focus on checking the settings by review, PG&E decided to see if test processes could be modified to identify these errors.

It was determined that the most accurate way to simulate relay fault test values is to take them directly from the system fault analysis program used by the protection engineer. The values are then scaled for secondary inputs and applied to the relay. This method ensures the applied values are realistic for the protected system. If the relay settings are incorrect the results of the applied fault test will fail, identifying the setting error.

PG&E now functionally tests integrated relay schemes with state simulated faults to prove the relay is set properly for the equipment it is protecting. The fault values are provided by the protection engineer directly from a system fault analysis program.

Selection Criteria for State Simulated Faults

- Best bang for the buck approach.
- Need maximum benefit for a minimum number of faults.
- Need to prove proper relay elements operate for in-section faults, and faults at zone boundaries, with the intended time delay.
- Need to prove proper relay operation (or non-operation) for out-of-section or reverse faults.
- Fault data is required for pilot schemes as well as non-pilot, since pilot terminals typically are put in service (as non-pilot) prior to performing end-to-end tests.
- Line faults for SAT testing should mirror those required for end-to-end faults as close as possible to minimize duplication of work for pilot schemes.

Using the above selection criteria it was determined that 7 faults would be sufficient for a typical two zone non-pilot scheme. 9 faults would be the maximum required for three zones of phase and ground distance. State simulated faults are not provided to prove secondary protection elements, such as LOP and Stub Bus. These are proven separately during the SAT as a go / no-go check of overall logic.

It is believed these additional tests provide a balanced approach to minimize exposure to misoperations due to setting errors. This requires some additional work by the protection engineer and relay technician, however they are necessary as part of PG&E's migration to integrated relay schemes and fill a void in the existing testing practice. These

tests are included as part of the relay Site Acceptance Testing (SAT).

State Simulated Faults for Line Protection

A summary of the state simulated faults provided for SAT line relay testing is listed below with the desired results. Refer to Figure 6 for a visual location of the faults.

Fault 1: 3-Phase at 50% of Line
- Proves Zone 1 3-Phase Distance Operation

Fault 2: Phase-Phase BC at 5% of Line
- Proves Zone 1 Phase-Phase Distance Operation and/or Phase Instantaneous

Fault 3: *Line-Ground at* 5% *of Line*
- Proves Ground Instantaneous Operation
- Proves Zone 1 Ground Distance Operation

Fault 4: Phase-Phase BC at 95% of Line
- Proves Zone 2 Phase-Phase Distance Operation
- Verifies Non-Operation of Zone 1 Phase Distance
- Verifies Non-Operation of Phase Instantaneous

Fault 5: Line-Ground at 95% of Line
- Proves Ground Time Overcurrent Operation or Zone 2 Ground Distance Operation
- Verifies Non-Operation of Zone 1 Ground Distance
- Verifies Non-Operation of Ground Instantaneous

Fault 6: Phase-Phase BC at Zone 3/4 Reach minus 10%
- Proves forward Zone 3 or Zone 4 Phase-Phase Distance Operation (if used)

Fault 7: Phase-Phase BC at Zone 3/4 Reach minus 10%
- Proves forward Zone 3 or Zone 4 Phase-Phase Distance Operation (if used)

Fault 8 & 9: Reverse Bus Faults – Phase-Phase & Line-Gnd
- Verifies Non-Operation of Relay
- Proves no elements are inadvertently set non-directional or in reverse direction

SAT Fault Template Spreadsheet

A fault data spreadsheet was created to streamline the process of providing state simulated fault data, reference Figures 7 and 8. A similar spreadsheet was already in use at PG&E for end-to-end test data, so the protection engineer and relay technicians were already familiar with this process.

- A fault template needs to be filled out for each MPAC or IPAC terminal.
- Fault values are required as part of SAT testing to prove relay settings and relay targets on the relay front panel, HMI and Master Station.
- Minimum numbers of faults are required. Spreadsheet "'grays out" faults not required depending on scenario, which is selected by radio button or check-box on summary screen tab.
- Data is entered into spreadsheet in primary values. Spreadsheet converts to secondary quantities.
- Secondary fault data is cut-and-pasted into test set software or imported directly by test set program.
- Expected test results and targets are listed on summary tab.

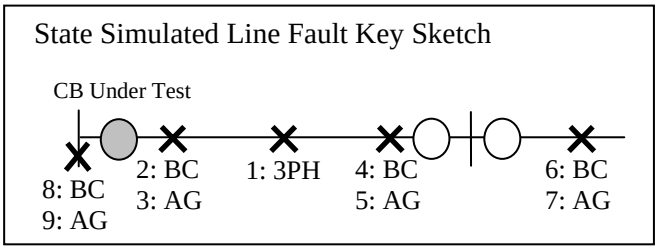

Fig. 6. Key Sketch for State Simulated Line Faults Provided for SAT Testing

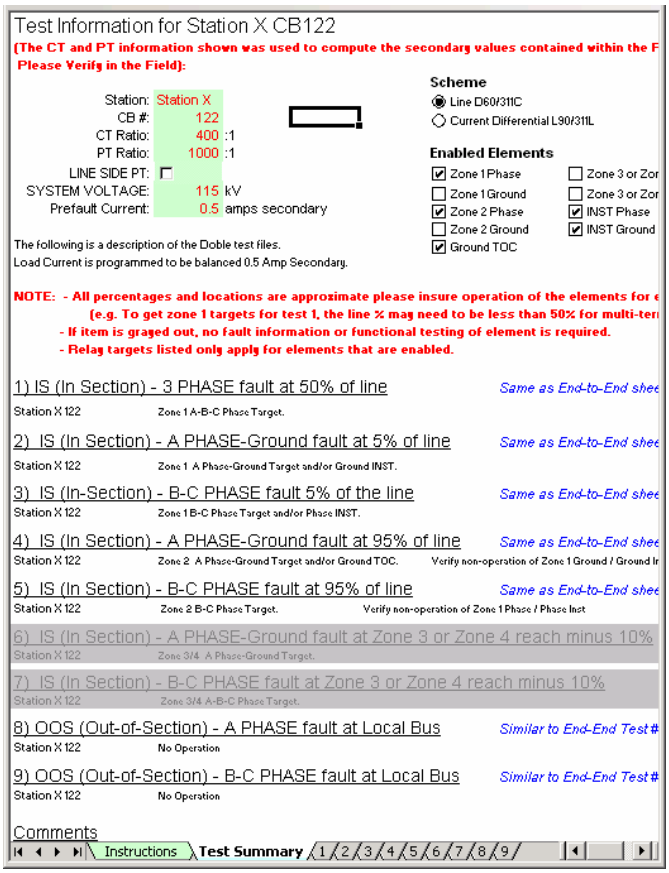

Fig. 7. State Simulated Fault Spreadsheet – Summary Tab for Line Faults for SAT Testing

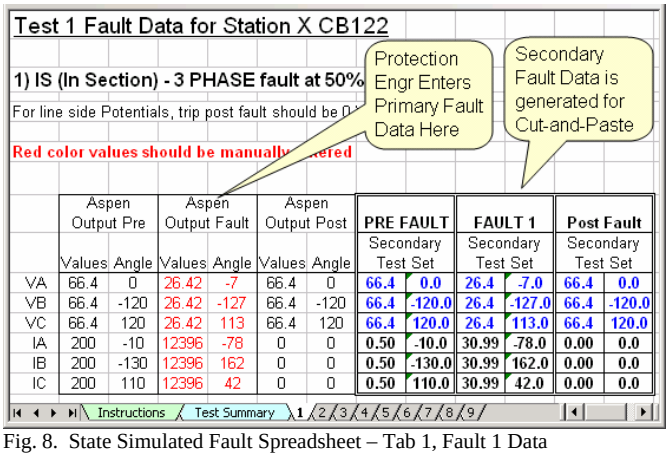

Fig. 8. State Simulated Fault Spreadsheet – Tab 1, Fault 1 Data

State Simulated Faults for Transformer Protection

State simulated faults are provided for SAT testing transformer protective relays, similar to those previously described for line protective relays.

VIII. Need For Logic Diagrams

Migration to Integrated Protection and Control (IPAC) schemes has created a logic intensive design where what was once traditionally hard-wired is now contained within relay logic. For a traditional non-integrated design, how a relay scheme functioned could normally be deduced from the schematic diagrams. This is no longer the case with integrated designs where the relay has become a black box, performing multiple protection, automation and control functions. Additionally, information shared between relays that used to be hard wired is now being shared through relay to relay communication, either with a direct digital connection from relay to relay or through network Ethernet communications such as IEC-61850 GSSE (Generic Substation State Event) or GOOSE (Generic Object Oriented Substation Event) standards.

To fully understand an integrated relay scheme requires an understanding of the relay logic. The easiest way to accomplish this is with a relay logic diagram. This lesson was learned on PG&E's Templeton project.

Templeton substation was the location for PG&E's first integrated control building with HMI. This was a single prototype installed in 2000 for design and evaluation purposes. The Templeton control building was a turn-key project where all engineering, including development of relay logic for protection, automatics, and SCADA control was done by the building provider. For the Templeton project relay logic diagrams were not developed or provided when the control building was initially put into service. Within the first year after being put into service a relay misoperation occurred. From this it became readily apparent that it was nearly impossible for the relay maintenance technicians and protection engineers to trouble shoot logic they were not familiar with for this one of a kind installation they inherited after it went into service. Within the first 3 years a total of 3 misoperations occurred due to errors in the relay logic that were not identified during testing prior to commissioning. This can be attributed in part due to the absence of logic diagrams and also not having a well defined test plan for proving the relay logic. In 2002 logic diagrams were developed for Templeton substation from the as-left, in-service relay settings. Part of this documentation process was to verify/correct the logic. No logic related misoperations have occurred since.

IX. MPAC Standard Logic Diagrams

Relay logic diagrams were developed as part of PG&E's Integrated Protection and Control Standards used for MPAC. Separate logic diagrams were created for Set "A" and Set "B" relay schemes. A sample logic diagram for Set "A" relay is shown in Figure 9. Logic diagrams include:

- Breaker Failure Logic
- Automatic Reclosing Logic
- Trip Logic
- Breaker Open/Close Logic
- Relay Pushbutton Controls for various functions such as CB Open, CB Close, Relay Cut-In/Out, Local/Remote, Auto/Manual, etc.
- Relay Remote Bit or Virtual Inputs initiated from SCADA/HMI for various control functions.
- Relay Remote I/O for relay to relay GOOSE Messaging (IEC-61850) over Ethernet.
- Contact Inputs and Outputs

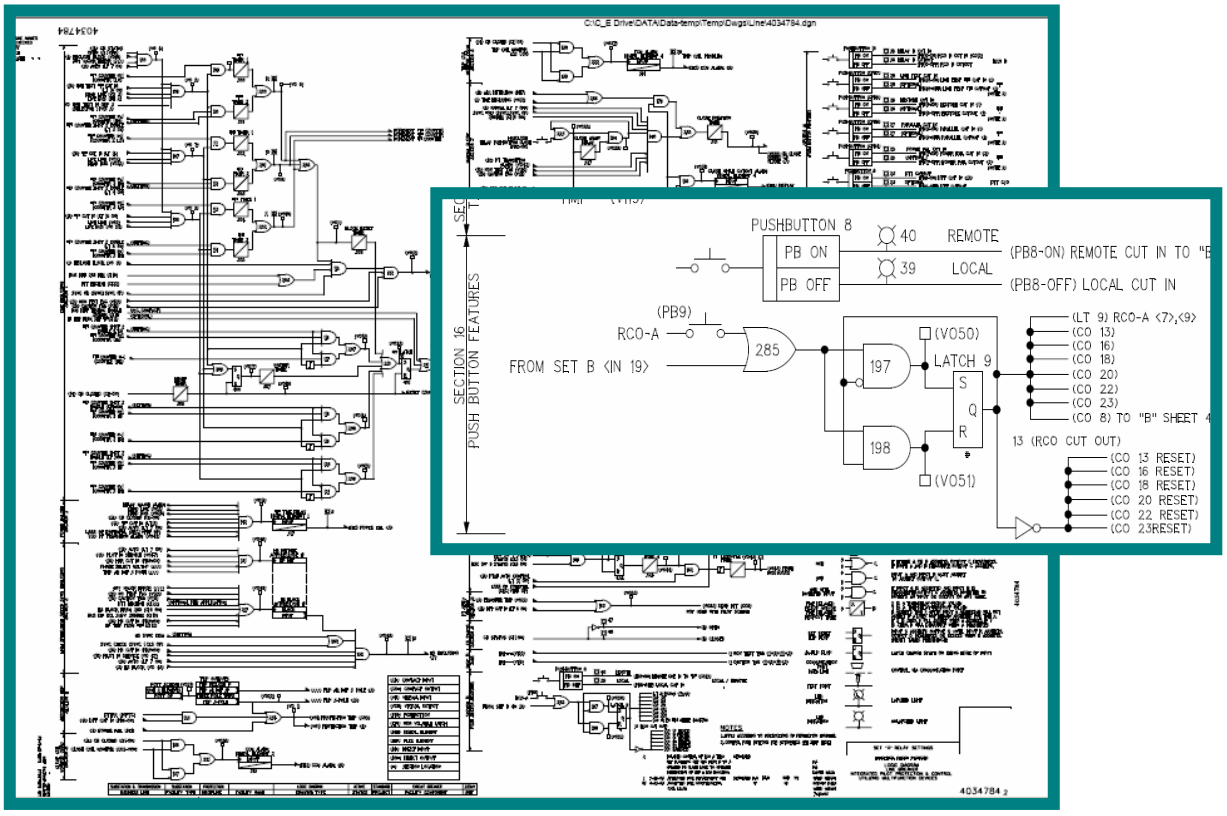

Fig. 9. Relay Logic Diagram for Set "A" Line Protective Relay

On the first MPAC projects it was debated whether logic diagrams should be created specifically for each project to reflect the final relay settings, as was done with Templeton. This would be costly and also difficult to manage in the engineering design process since final relay settings would need to be provided much sooner. Also, any logic corrections or changes made during FAT and SAT testing would have to then be corrected on the logic diagrams. In the end it was decided not to create project specific logic diagrams, but rather to use the standard logic diagrams created with PG&E's IPAC Standards. To make this a workable solution the relay setting template base logic needed to be standardized to a very high degree. The relay setting templates were developed to include logic for all standard features. The intent is that the entire template base logic will be left within the relay, and for features not used logic would only be turned off or disabled, and not deleted. This approach has been successful. It is understood that there may be minor deviations in the project relay settings from the standard logic diagrams, however 90% of the base logic is unchanged and the standard logic diagrams provide a good roadmap for understanding and trouble-shooting the relay scheme.

X. Combined Logic Diagrams

Second generation IPAC standards developed by PG&E made use of GOOSE Messaging (IEC-61850) for transmitting Remote I/O over Ethernet for relay to relay control and status information for Ring Bus and Breaker-and-a-Half design standards. This added an additional level of complexity to the relay schemes. To aid in understanding these complex schemes, functional overview sketches were created. These sketches graphically showed relay Remote I/O device to device connections and partial internal relay logic. The sample shown in Figure 10 and Figure 11 is to illustrate Breaker Failure and Stub Bus block reclosing which is done through Remote I/O.

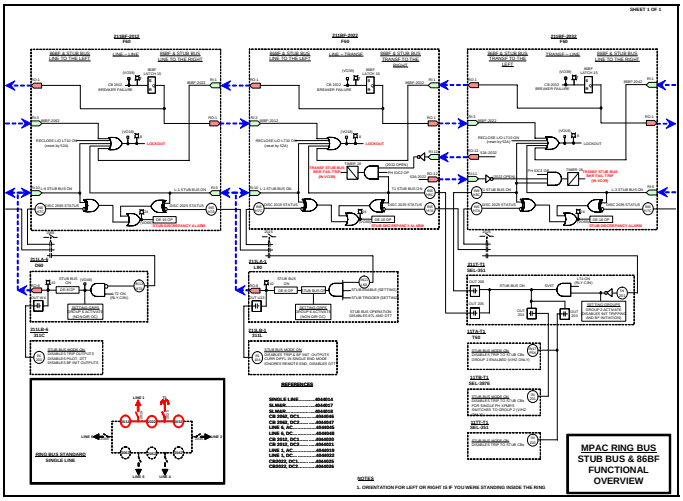

Fig. 10. Sample Combined Logic Diagram

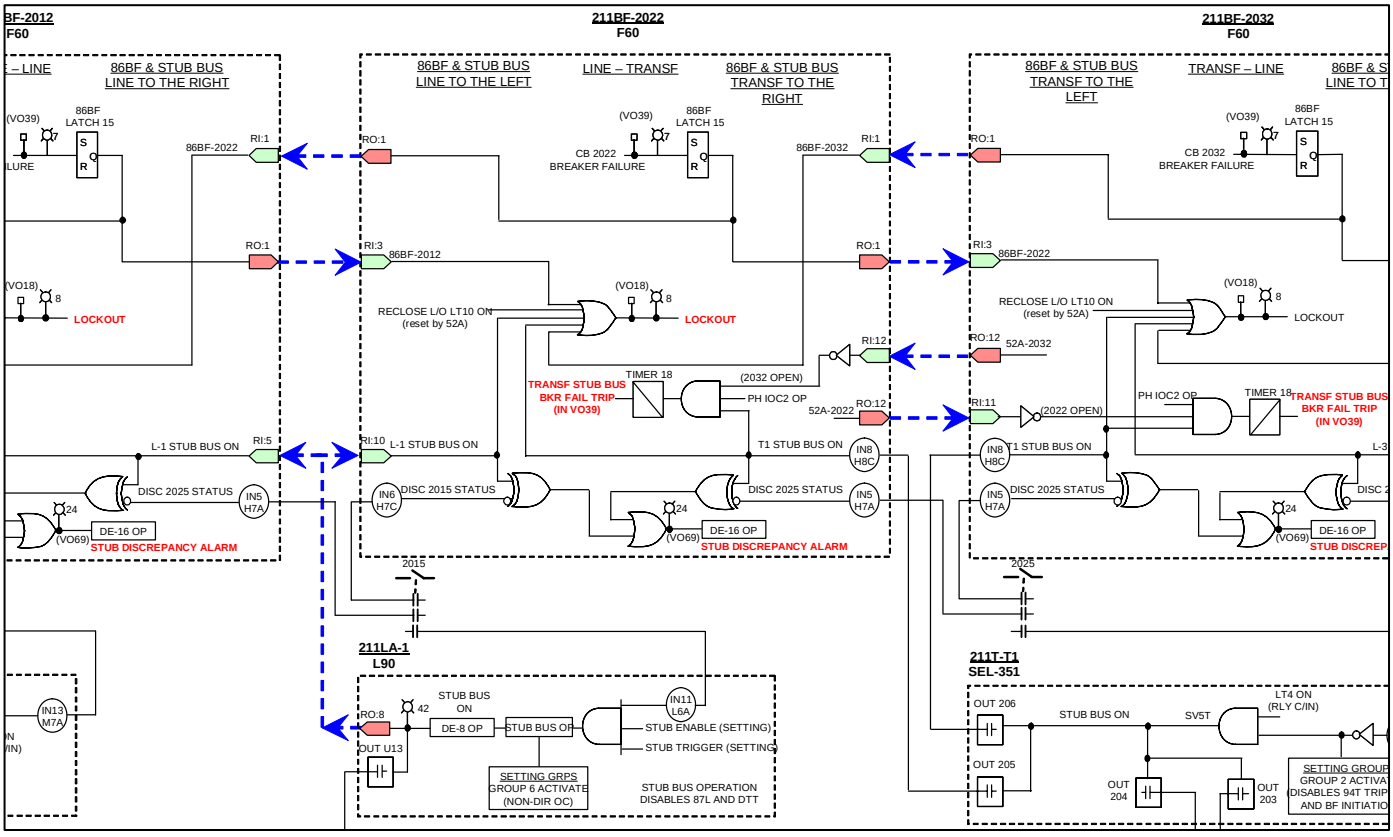

Fig. 11. Sample Combined Logic Diagram (Zoomed In View)

XI. Remote I/O Mapping

PG&E utilizes Remote I/O GOOSE Messaging (IEC-61850) in Breaker-and-a-Half and Ring Bus design standards for transmitting relay to relay control and status information. Remote I/O are used for non-trip functions such as:

- Block Reclosing to adjacent breakers for breaker failure
- High Speed Reclosing Interlock for adjacent CBs
- Stub Bus Protection Mode
- Breaker Maintenance Function
- Breaker Status

Due to the number of Remote I/O used and the number of relays involved, it is very difficult to get all of the Remote I/O set properly on the first attempt. Errors inevitably happen and are caught during scheme testing such as during the SAT testing. A very useful tool to help properly configure Remote I/O is to list all devices and Remote I/O in a single spreadsheet as shown in Figure 13. Assign a column for each relay, and a row for every Remote Output. After assigning all of the Remote Outputs, then list the Remote Inputs in the same row as corresponding Remote Output. Figure 12 shows the single-line configuration for the Remote I/O spreadsheet in Figure 13.

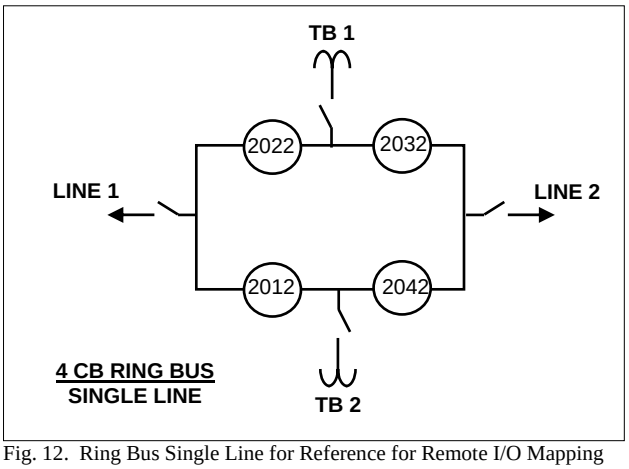

Fig. 12. Ring Bus Single Line for Reference for Remote I/O Mapping

	REMOTE I/O-- RING BUS - 4 CBS	CB 2012	LINE 1	CB 2022	Transf 1	CB 2032	LINE 2	CB 2042	Transf 2
		F60-2012	D60-1	F60-2022	T60-1	F60-2032	D60-2	F60-2042	T60-2
Device / Output	DEVICE:	1	2	3	4	5	6	7	8
1.1	BFT BLOCK AUTO (86BF) LT15	RO:1		RI:3				RI:1	
1.3	BFT TO DTT	RO:3	RI:2						
1.2	HS 1ONLY INTLK TO LEFT (PB 3)	RO:2						RI:2	
1.4	HS 1ONLY INTLK TO RIGHT (PB 4)	RO:4		RI:4					
1.5	CBM CONTROL TO LEFT (CPB 3)	RO:6						RI:7	
1.6	CBM CONTROL TO RIGHT (CPB 3)	RO:5		RI:6					
1.7	CBM LT13 TO LEFT	RO:7						RI:8	RI:8
1.8	CBM LT14 TO RIGHT	RO:8	RI:9	RI:9					
1.12	52A 20n2	RO:12		RI:11				RI:12	
2.8	STUB BUS STAT	RI:5	RO:8	RI:10					
2.15	REMOTE BLK CLOSE (NOT USED)	RI:15	RO:15	RI:16					
3.1	BFT BLOCK AUTO (86BF) LT15	RI:1		RO:1		RI:3			
3.3	BFT TO DTT		RI:1	RO:3					
3.2	HS 1ONLY INTLK TO LEFT (PB 3)	RI:2		RO:2					
3.4	HS 1ONLY INTLK TO RIGHT (PB 4)			RO:4		RI:4			
3.5	CBM CONTROL TO LEFT (CPB 3)	RI:7		RO:6					
3.6	CBM CONTROL TO RIGHT (CPB 3)			RO:5		RI:6			
3.7	CBM LT13 TO LEFT	RI:8	RI:8	RO:7					
3.8	CBM LT14 TO RIGHT			RO:8	RI:9	RI:9			
3.12	52A 20n2	RI:12		RO:12		RI:11			
4.8	STUB BUS STAT								
4.15	REMOTE BLK CLOSE								
5.1	BFT BLOCK AUTO (86BF) LT15			RI:1		RO:1		RI:3	
5.3	BFT TO DTT					RO:3	RI:2		
5.2	HS 1ONLY INTLK TO LEFT (PB 3)			RI:2		RO:2			
5.4	HS 1ONLY INTLK TO RIGHT (PB 4)					RO:4		RI:4	
5.5	CBM CONTROL TO LEFT (CPB 3)			RI:7		RO:6			
5.6	CBM CONTROL TO RIGHT (CPB 3)					RO:5		RI:6	
5.7	CBM LT13 TO LEFT			RI:8	RI:8	RO:7			
5.8	CBM LT14 TO RIGHT					RO:8	RI:9	RI:9	
5.12	52A 20n2			RI:12		RO:12		RI:11	
6.8	STUB BUS STAT					RI:5	RO:8	RI:10	
6.15	REMOTE BLK CLOSE (NOT USED)					RI:15	RO:15	RI:16	
7.1	BFT BLOCK AUTO (86BF) LT15	RI:3				RI:1		RO:1	
7.3	BFT TO DTT						RI:1	RO:3	
7.2	HS 1ONLY INTLK TO LEFT (PB 3)					RI:2		RO:2	
7.4	HS 1ONLY INTLK TO RIGHT (PB 4)	RI:4						RO:4	
7.5	CBM CONTROL TO LEFT (CPB 3)					RI:7		RO:6	
7.6	CBM CONTROL TO RIGHT (CPB 3)	RI:6						RO:5	
7.7	CBM LT13 TO LEFT					RI:8	RI:8	RO:7	
7.8	CBM LT14 TO RIGHT	RI:9						RO:8	RI:9
7.12	52A 20n2	RI:11				RI:12		RO:12	
8.8	STUB BUS STAT								
8.15	REMOTE BLK CLS								

Fig. 13. Ring Bus Remote I/O Mapping for 4 Breaker Ring

XII. Contact Input Debounce Timer Settings

One of the early lessons learned with PG&E integrated protection and control was the importance and criticality of contact input debounce timer settings. Initially PG&E setting templates left the microprocessor relay input debounce timer settings at the manufacturer default, which was 2 msec for Set "A" relay and 4 msec for Set "B" relay. This led to undesired relay action in a few cases due to DC transients. Relay inputs that were wired to circuits running outdoors were found to be particularly susceptible to being picked up by DC transients. This was the case with PG&E integrated transformer protection.

Part of PG&E integrated protection and control philosophy is the elimination of auxiliary relays. Instead of using an auxiliary relay to multiply contacts, additional Set "A" and Set "B" relay outputs are used. As it pertains to transformer protection PG&E uses the Set "A" differential relay to serve as the tripping relay for the transformer mechanical devices (Conservator Oil Flow, Sudden Pressure, Low Oil). Contacts outputs from the mechanical devices are wired to the Set "A" relay inputs. It was learned that by using a microprocessor relay as a tripping auxiliary relay, you lose some immunity to DC transients that was inherent with the mechanical auxiliary relays used in older schemes. To compensate for this, additional delay must be added to the contact input debounce timer settings on the Set "A" and Set "B" microprocessor relays. This will slow down the scheme, but is unavoidable.

This lesson was learned after integrated protection and control was first applied for transformer protection. PG&E experienced false tripping at 3 substations within a very short time frame. In all 3 cases, the false trip targeted as Conservator Oil Flow relay. The Conservator Oil Flow (63TF) trip target LED resides on the Set "A" transformer differential. The Conservator Oil Flow relay has an "a" seal wired to the Set "A" differential relay that initiates tripping with no time delay. These false trips were determined to be caused by DC transients. In all 3 cases, data from the relays sequence of events records indicated the DC transients picked up the relay inputs for durations between 2 and 4 msec. The DC transients picked up all of the Set "A" relay inputs wired to the transformer mechanical devices, reference Figure 14. However, no false trips occurred from the Sudden Pressure Relay (63T) inputs since PG&E requires a change of state from both an "a" seal and "b" seal for tripping to occur. The LTC Low Oil (71QLTC) input also did not cause a false trip since this function has time delayed tripping. Following these events PG&E increased the default debounce timer settings to 16 msec for all direct tripping inputs. No further false operations of this type have occurred since.

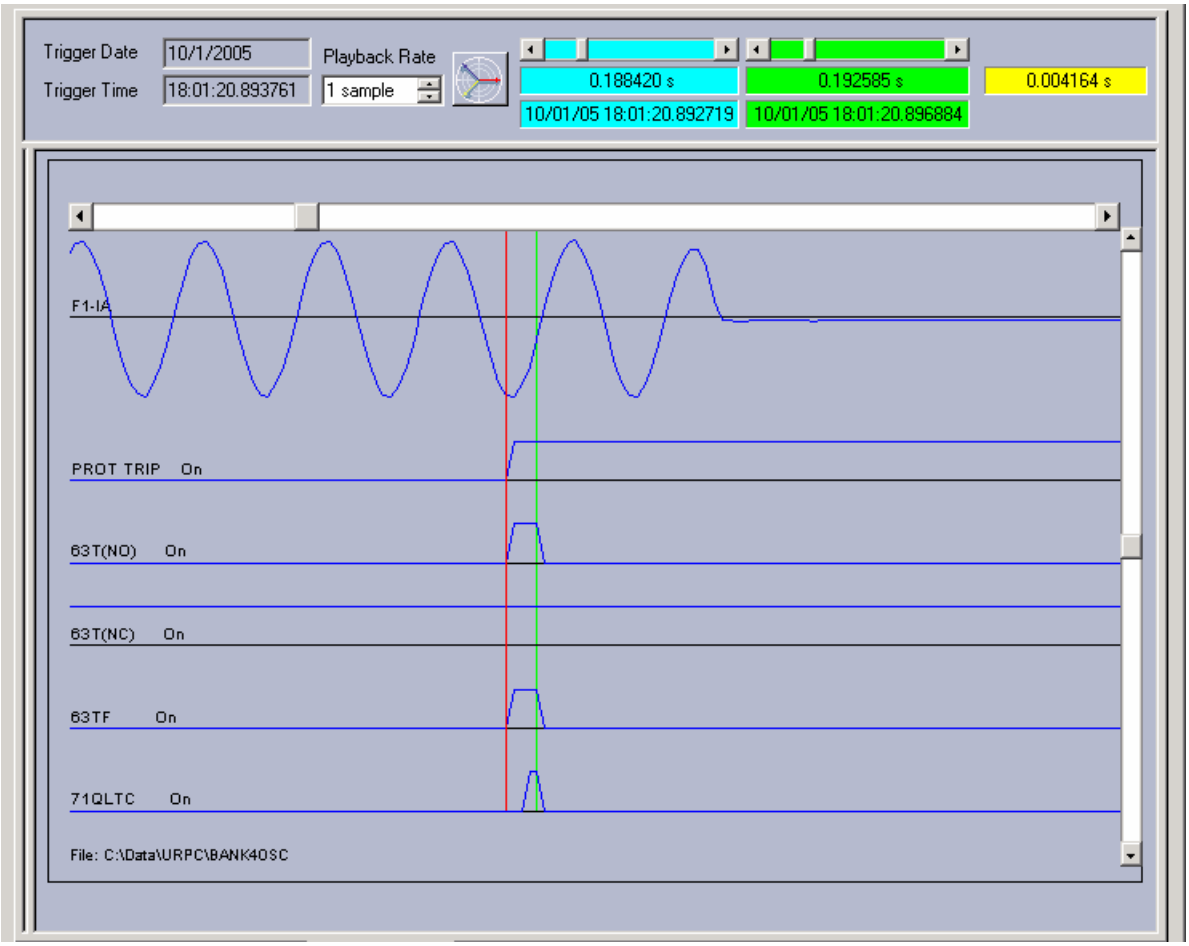

Fig. 14. Set "A" Oscillography for Conservator Oil Flow (63TF) false operation due to DC transient asserting trip input.

XIII. Set "A" / Set "B" Control Logic

When PG&E developed IPAC standards it was not possible to digitally share information between the Set "A" and Set "B" relays selected. Therefore, status and control information was shared by the physical wiring of contact inputs and contact outputs between the relays.

Most control functions can be toggled by Set "A" pushbutton action or Set "B" SCADA/HMI remote bit commands as shown in Figure 14 below. To initiate a control command between the Set "A" and Set "B" relays an output contact can either be pulsed momentarily or closed (latched) continuously until the feature needs reset. There are advantages and disadvantages to each method. If pulsed output logic is used, the corresponding input on the other relay sets and resets a latch on the contact input rising edge only. If a latched output is used the corresponding input on the other relay sets a latch on the contact input rising edge, and resets the same latch on the contact input falling edge.

In most cases PG&E pulses control outputs to send commands between the relays. The advantage to this is it allows isolating the relay inputs and outputs by opening relay FT switches without causing an inadvertent change of state to one of the relays latches. The pulsed control outputs are always normally open and only close momentarily when a command is issued.

The disadvantage to pulsed control output logic is the susceptibility to a change of state being initiated by a DC transient. If a DC transient asserts a contact input momentarily, it will have the same effect as a control command between the relays. This happened on one of the early MPAC projects. An MPAC relay that was cut-in changed to the cut-out state without any Operator action. This was captured in the relays' sequence of events records where the Set "A" relay input was asserted and the Set "B" relay output wired to the Set "A" input did not assert. A DC ground was later found in the MPAC building emergency lighting that was the cause of the DC transient. To desensitize the relay inputs, the contact input debounce timer settings were increased as described in the previous section.

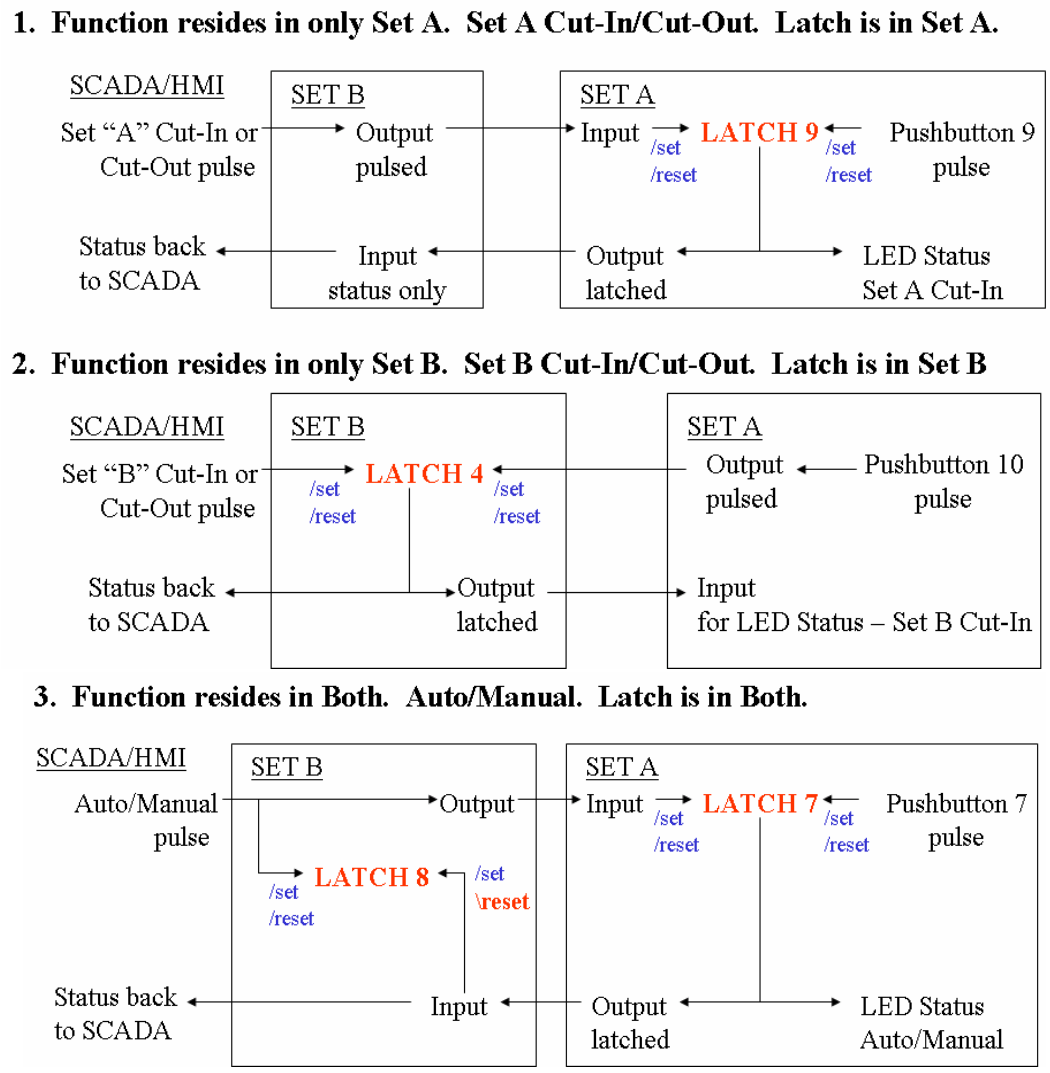

Fig. 15. Set "A" and Set "B" SCADA and Pushbutton Control Logic Overview

XIV. Standard SCADA/HMI Screens

One of the keys to the success of PG&E's MPAC program is standardization. This applies to the SCADA/HMI screens as well. Prior to MPAC rollout the SCADA screens in different control center jurisdictions were inconsistent due to individual operator preferences that were accommodated by the SCADA specialists who created the screens. In addition to defining the standard screens, additional challenges arose that were unique to MPAC.

A. Overview of Functionality

All MPAC HMI screens are replicated at the SCADA master station at the control center with jurisdiction. In almost all instances, the operators have the same control from their PCs as with the substation HMI. In substations with more than one MPAC building, each HMI has full functionality for that station.

B. MPAC Alarm and Annunciator Screens

One of the lessons learned on the first few MPAC buildings was the Operators were being bombarded by SCADA alarms from the MPAC buildings. Since the alarms were so frequent and numerous the Operators began experiencing information overload and began ignoring the alarms. Most of the alarms were minor and were due to various equipment being cut-in/out or powered up/down due to testing that was still in-progress in the substation. The alarms were being received through SCADA in a tabular format that was not user friendly. Additionally, there were many duplicate alarms where the same information was being reported by multiple relays.

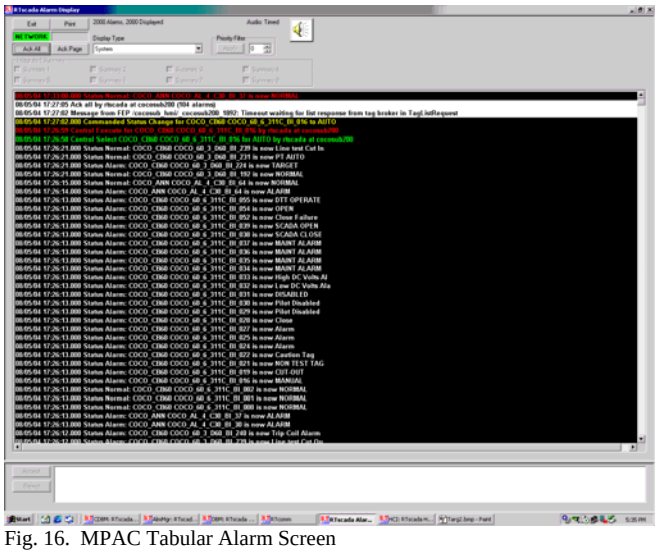

Fig. 16. MPAC Tabular Alarm Screen

To resolve the alarm overload issue, alarms were categorized into eight levels, with Level 8 being the most critical alarms, and Level 1 being non-critical or informational. Level 8 provides only breaker operations for a high level overview. Level 3 and above provides all critical alarms. A graphical HMI annunciator screen was also created for the most critical alarms as shown in Figure 17. The HMI annunciator screen mimics the functionality of a traditional substation annunciator. The annunciator page contains a grid of panes that indicate what major equipment is in alarm state. Each pane that announces trouble will flash until acknowledged. If a station is large, there will be one grid for each bus section, or each MPAC building, where there is more than one building in the substation.

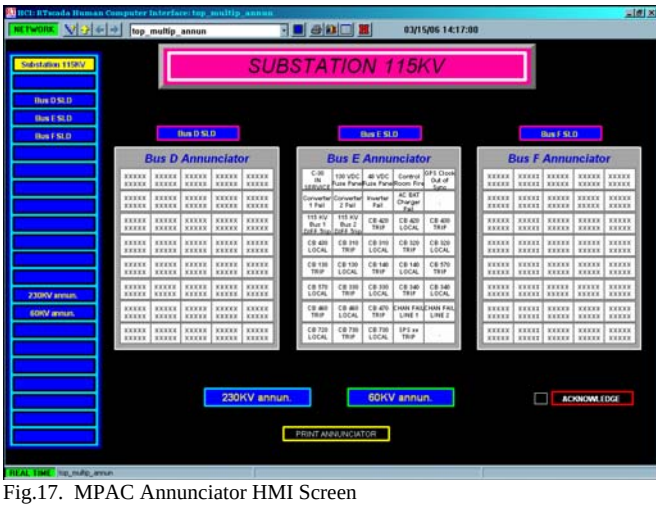

Fig.17. MPAC Annunciator HMI Screen

C. MPAC Sync Scope Screen

A sync scope screen was not initially implemented for MPAC. This is because all breaker closing is done through either the Set "A" or Set "B" protective relay and is supervised by internal relay synch check elements. This includes breaker close commands issued from the HMI or SCADA master station, as well as from the relay close pushbutton or reclosing relay.

PG&E however has a large hydro-electric system. Some of the first MPAC buildings installed included transmission lines feeding hydro systems with blocks of load that could become islanded. Operating personnel took exception to not having a sync scope. When an islanding condition occurs a synch scope is needed so that direction can be provided to the remote hydro generator to speed up, slow down, or raise or lower voltage. Once the two systems are brought into an in-sync condition the MPAC relays will then allow a close to parallel the two systems.

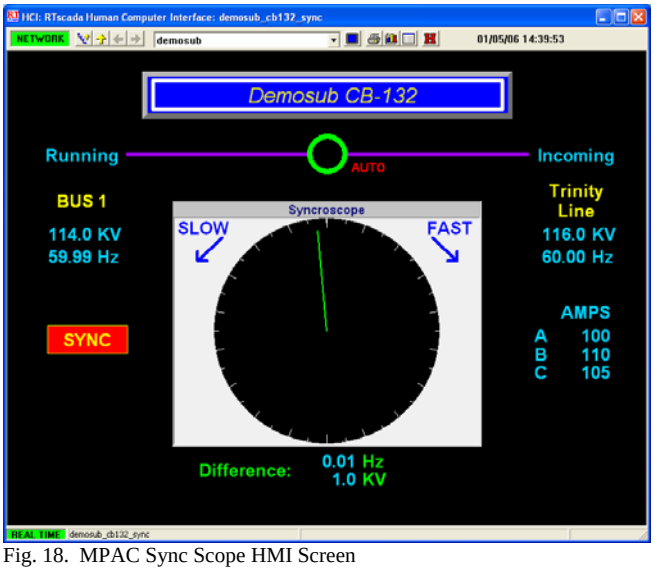

Fig. 18. MPAC Sync Scope HMI Screen

To provide this functionality an HMI sync scope screen was implemented as shown in Figure 18. The sync scope screen is a representation of the systems on either side of an open breaker. Frequency, volts, and phase angle differences are indicated on the screen. Also, the CB is depicted on, and can be closed from, the sync screen. The sweep-hand on the sync scope is not a true scope, only a visual representation of the degree of out-of-sync status and the direction (fast or slow). When there is an out-of-sync condition, the "NO SYNC" box will be displayed. When the systems are close enough for a close, the "SYNC" box will appear and the operator may call for a close at that time. With this representation of conditions, the scope's twelve o'clock position has no bearing on the timing of the close command. The close command will be held in the protection relay until the sync point is achieved, or it will "time out" if the sync conditions are outside of the maximum tolerance for a successful parallel of the systems. It should be noted that HMI sync scope has a finite sample rate due to the relays and if the frequency of the two systems is far apart the sweep hand will jump around.

XV. Training

Migration to integrated protection and control requires an adjustment for Operators who must learn a different method of work. To provide training for Operators, PG&E constructed an MPAC simulator at its San Ramon Valley Learning Center.

The MPAC simulator is setup to simulate a working control room for a 230/115kV substation. The 230kV portion is setup to emulate a breaker-and-a-half bus configuration with a single bay consisting of one line and one 230/115kV transformer bank. The 115kV portion is setup to emulate a single-breaker double-bus configuration. The 115kV bus includes one bus parallel breaker, one breaker for the 230/115kV transformer, and two 115kV lines setup as a hybrid protective scheme with power line carrier transceivers wired back-to-back.

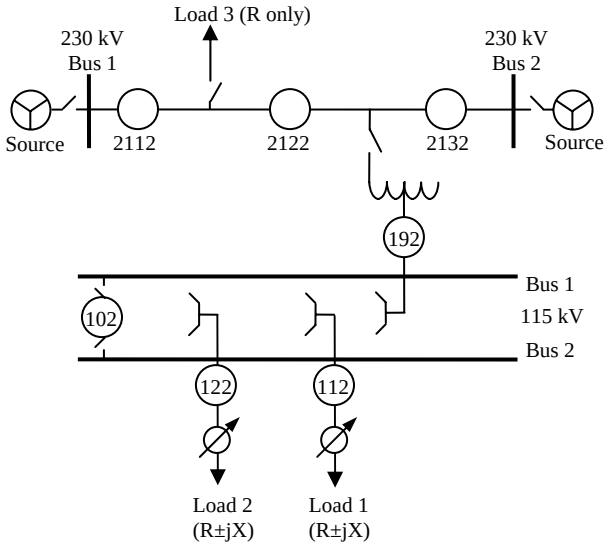

Fig. 19. MPAC Training Simulator Single Line Diagram

Relay racks were installed in a large classroom lab with the protection and control equipment required to operate and protect the fictitious substation equipment. A working HMI computer was also installed and a communication rack with the necessary equipment to fully automate the substation and allow remote SCADA control from the Operations Control Center training room.

The simulator includes a load bank that provides secondary current to the protective relays to simulate load conditions. The 230kV busses serve as sources and the 230kV and 115kV lines act as loads. The 115kV loads contain resistive and reactive elements that can be varied to provide a range of power factors. The 230kV line load is only resistive. Individual sources and loads can be switched on and off. How the load flows depends on the position of panel switches installed to simulate breaker, bus, line, and transformer outdoor disconnect switch positions (reference Figure 20). Simulated breaker open and close position also affects load flow. Breaker simulators were installed to provide a trip coil, close coil, and breaker status to the relays.

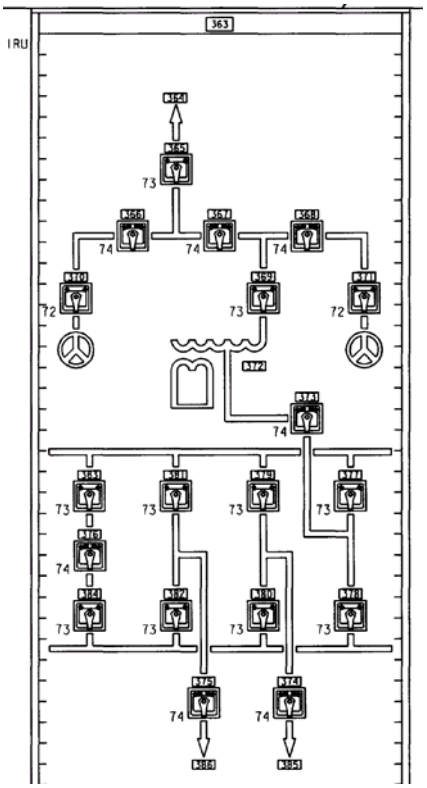

Fig. 20. Panel for switches used to simulate breaker, bus, line and transformer disconnect switch positions.

Fault Scenarios

The load bank is also used simulate low level fault conditions (less than 10 amps secondary) to the relays. This allows training modules to contain various fault scenarios that operate the protective relays. In turn, the students can see how the substation operates for various fault conditions and what relay targets are generated. Fault conditions can be either momentary or sustained. Some of the fault scenarios include:

- Transformer Fault and Lockout

- 115kV Line Fault with Pilot Trip and High Speed Reclose
- 230kV Line Fault with CB 2122 Breaker Failure
- 230kV Stub Bus Fault

The instructor can initiate the fault scenarios from a PLC touch screen interface that is located in the Operations Control Center training room. Faults can also be initiated from a second PLC touch screen that is in the lab where the MPAC simulator resides. The PLC automatically adjusts the load elements to preset values and switches them on for the required fault duration.

Technician Training

In addition to the Operator training classes, the MPAC simulator is also used to provide relay technician training classes with the latest integrated protection. Some of the training items covered include:

- Integrated Protection and Control Standards
- Relay logic
- Use of relay software
- Communicating with relays through substation local Ethernet network
- Basic trouble shooting of relay logic
- SAT testing
- End-to-end testing

Training for end-to-end testing is done using the protective relays on the two 115kV line panels. The 115kV line panels include power line carrier transceivers that are hooked up back-to-back for communication so that the two panels operate as a two terminal line. The technicians isolate the relay current and potential inputs from the simulator load bank via relay test switches and spade in current and potential from test sets as would normally be done for end-to-end tests.

Other Uses for MPAC Simulator

The MPAC simulator has also proven valuable as a tool for research and development. It provides a working substation control room environment where all the equipment can be operated with no impact to PG&E customers. The MPAC simulator has been used to:

- Test and evaluate new communications equipment
- Test and evaluate a new universal power line carrier transceiver
- Upgrade relays to newer firmware versions for evaluation purposes
- Test various new SCADA and automation features
- Test logic changes

XVI. Concluding Remarks

In conclusion, PG&E has been successful in applying Modular Protection Automation and Control (MPAC) buildings by implementing a continuous improvement process. In progress and completed projects are reviewed to determine if improvements are needed to streamline the installation and testing processes. This is a requirement for each project being conducted at PG&E. PG&E presently has 28 MPAC buildings fully or partially in-service and has installed over 900 integrated relays in MPAC buildings and retrofit jobs in existing substation control rooms since 2004.

XVII. References

[1] Chris Araujo, Fred Horvath, and Jim Mack, "A Comparison of Line Relay System Testing Methods," presented at the 33rd Annual Western Protective Relay Conference, Spokane, WA, October 2006.

[2] A.T. Giuliante, A. & M. Makki, and Jeff Taffuri, "New Techniques for Dynamic Relay Testing," presented at the 33rd Annual Western Protective Relay Conference, Spokane, WA, October 2006.

[3] Farshid Brojeni, Eugene Shulman, and Manish Thakur, "Novel Integrated Protection and Control Schemes for Distribution Feeders," presented at the 33rd Annual Western Protective Relay Conference, Spokane, WA, October 2006.

XVIII. Biographies

Aaron Feathers received his BS in Electrical Engineering from California Polytechnic State University, San Luis Obispo in 1992. He started his career with Pacific Gas and Electric Company in 1991 as an engineering intern. Since then he has held various positions including Protection Engineer, Senior Protection Engineer, Substation (Design) Engineer, Maintenance & Construction Engineer, Supervising Substation Engineer, and Supervising Protection Engineer. Aaron has been on special assignment since 2004 supporting PG&E's Modular Protection and Control (MPAC) initiative providing protection, integration, automation, design and test support and working as part of an MPAC core team responsible for development of standards, processes, templates and overall program oversight. Aaron is a registered professional engineer in the state of California.

Lyle Whitson is a recent retiree from Pacific Gas and Electric Company. He has over 35 years of electrical substation, protective relaying, and telecommunications experience. He has held various positions including Apprentice Electrician, Electrician, Apprentice Telecommunications Technician, Telecommunications Technician, Apprentice Electrical Technician, Electrical Technician, Supervisor of Substation Maintenance personnel, Protection Specialist, Senior Protection Specialist, and Supervising Specialist. Since 1994, he has been involved with the development of test procedures and maintenance requirements for protective relaying schemes at PG&E. Prior to his retirement in September 2007, he was on special assignment developing and supporting the testing requirements for PG&E's Modular Protection and Control (MPAC) equipment being performed by the equipment supplier and PG&E personnel.

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