WHITE PAPER

Pilot implementation of Centralized Protection and Control – SRP Experience

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The concept of Centralized Protection and Control (CPC) is over fifty years old in the electrical industry. Several experimental systems have been implemented since then by various companies and utilities. With the limited computing capability and critical data communication technologies available in the past, a commercially viable CPC system was rather difficult to achieve. The launch of global standard for Power System applications in the year 2004, viz., IEC 61850 has been a game changer enabling Power System industry to explore more efficient ways of utilizing the assets while reducing cost over the entire life cycle of the project. With the advanced computing capabilities of modern microprocessors and the matured IEC 61580 standard, the concept of centralized protection is now a reality. The CPC system is based on a flexible distribution or even a replication of protection and control functions between devices at feeder and substation levels via a highly available and fast Ethernet network based on the IEC 61850 standard.

Salt River Project's (SRP) vision to move from a distributed PAC approach to a centralized PAC approach was born out of the necessity, to reduce the number of devices being installed and improve their overall life cycle strategy. The challenges with past PAC approaches included installing devices within harsh environments that reach extreme temperatures, a lack of flexibility in the distribution of signals, and a large amount of required labor (both now and during future maintenance and replacements). As an advanced step, SRP decided to implement a pilot project at one of their 69/12.47 kV substations. The system configuration comprises of dedicated merging units (MU) and a CPC device, with the protection, measurement, control, fault recording, sequence of events for the transformer and the outgoing feeders concentrated in the CPC unit. This paper presents the details of the CPC pilot implementation, beginning with the design concepts, engineering methodology adopted, installation, testing, commissioning, and performance evaluation of the system. Even though the COVID-19 pandemic threw some additional challenges during the implementation stage, the pilot project was successfully installed in mid-2020. The lessons learned at various stages of the project implementation are also discussed. The authors hope that the lessons learned from this project will be valuable to the power systems industry in adopting advanced digital technologies to make their substation protection and control more adaptable and reliable, thus improving the protection of their assets and efficiency in operation and maintenance.

I. Introduction

The electrical power distribution grid is rapidly changing with the constant addition of distributed energy resources, modernization of the grid from radial to ring configuration to reduce the power supply interruptions and to meet the ever-growing energy demand. Many utilities are in the process of converting the overhead distribution lines to underground cables to increase the asset reliability and weather proofing purposes. All these changes in the system call for additional or new protection and control functions to adequately protect and monitor the grid. Utilities and industries are looking to efficient ways of addressing these concerns with the long-term view of improving the overall life cycle strategy of microprocessor relays. Centralized protection and control (CPC) concept can play a key role in addressing these requirements in an efficient manner, utilizing the power of modern microprocessor technologies and standardized data modelling and communication architecture offered by IEC 61850 standard. The paper starts with the vision of Salt River Project's (SRP) to efficiently manage their PAC assets in their growing grid. It then discusses CPC concept and its basic components, some of the key design considerations and then goes into the details of the pilot project implemented by SRP. The paper explains the key steps involved in engineering the CPC system, details of installation, testing and commissioning of the pilot project. Further, some of the important lessons learned during the implementation and the evaluation of the CPC system are explained. The paper concludes with suggestions to take the centralized protection concept to the next level.

II. SRP vision

The original motivation behind SRP's migration away from distributed, system-element-based protection packages, was due to detailed life cycle planning for substation protection and control (PAC) assets. The replacement and upgrade programs in place for keeping up with the expected longevity of existing devices were realized to be drastically insufficient. Focusing solely on distribution equipment there is a large amount of existing infrastructure (nearly 450 distribution bays) coupled with a staggering amount of metropolitan growth in the Phoenix area. Present microprocessor-based device life spans dictate a 20-25 year replacement rate, which equates to upgrading 20+ bays annually if the par rate is to merely be maintained. Given their present workforce capabilities and existing standards, this was not attainable.

In addition to quantity, there is also a large variety of installation types to manage, due to the standards changes over the past decades (the oldest of the fleet being 60+ years old). These comprise of many different ages and vintages (electromechanical, solid state, first- and second-generation microprocessor), and designs were often altered to cover station arrangements that deviated from standard to accommodate specific site and customer limitations and preferences. Therefore, it became clear that a consolidated, centralized solution was needed. This would not only reduce the number of devices per bay while implementing a package that suits all configurations but could simultaneously improve other areas of concern surrounding personnel safety, redundancy, communications reliability and security, cost, and time spent on design, construction, and maintenance.

SRP has spent the past several years revising their standards to introduce a new, consolidated protection and control package. Additionally, they decided to implement a pilot CPC system in their 69/12kV Pima Substation. They chose a commercially available CPC device from a relay vendor with global operations and proven field experience with modern microprocessor technologies and digital systems based on IEC 61850 standard. The design, implementation and evaluation of the CPC system are detailed in the next sections.

III. CPC system design

The CPC system is implemented on Bay 3 of the 69/12.47 kV Pima Substation. Circuit breaker (CB) 335 controls the 69 kV side of the transformer. CB 132, 133, 134, 135 are the 12 kV feeder breakers. In the CPC system the merging units are named to match with the existing substation equipment naming for easy identification. The existing standard protection and control functions are indicated in Figure 1. The description of protection and control functions are indicated in Table 1.

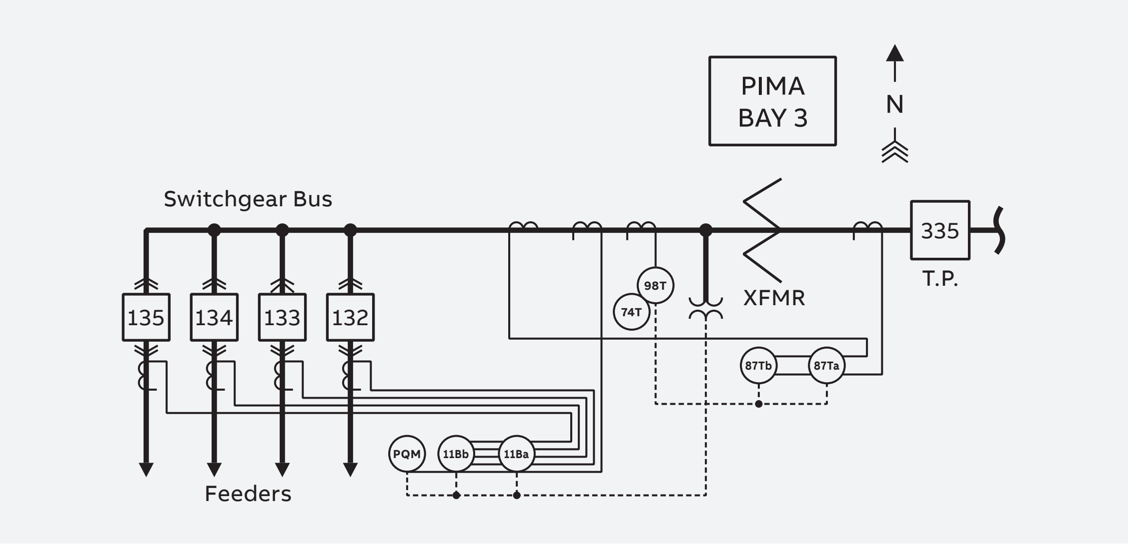

Figure 1: Existing standard PAC – 69/12.47 kV Pima Substation Bay 3

Relay	Description
11B	Trips/Blocks close on 12 kV main and feeder breakers for bus fault (87 - Virtual LO)
	Trips main for any feeder breaker failure (50BF)
	Trips 12 kV feeder breakers (50, 51, 27)
	Recloses feeder breaker following an individual feeder fault, or all feeders following a 27 or 81 operation
	Operates 12 kV main and feeder breakers (Supervisory control)
	Provides remote alarms, indication and status
87T	Trips/Blocks close on 12 kV main breaker and 69 kV T.P. for transformer fault (86P or 87 - Virtual LO)
	Trips/Blocks close on 12 kV feeder breakers and 69 kV T.P. for low side breaker failure (50BF - Virtual LO)
	Trips 12 kV main breaker for transformer overload (51)
	Trips 12 kV feeder breakers for underfrequency (81)
	Operates 69kV T.P. (Supervisory control)
	Provides remote alarms, indication and status

Table 1: Existing standard relay protection and its function description

A. CPC concept

The main idea of centralized protection concept is to move protection and control from multiple bay level devices to a single central processing unit. As the protection and control relays are executing similar tasks, it is logical to centralize the functionality in one single location. A simplified CPC concept diagram is shown in Figure 2.

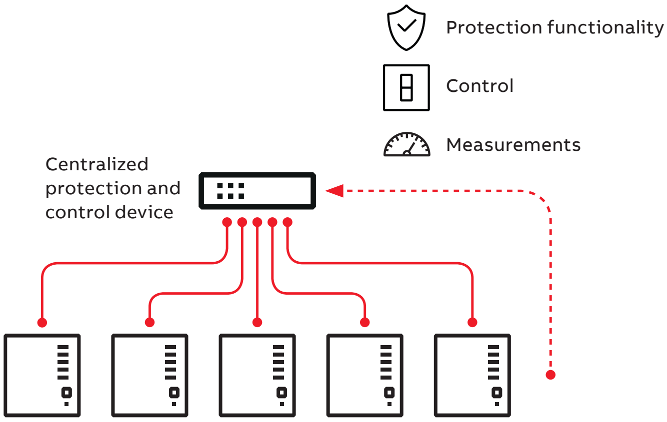

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Figure 2: Simplified diagram of a CPC system

B. CPC system components

CPC device: The main component of a CPC system is obviously the CPC device. It is a high-performance computing platform capable of providing protection, control, monitoring, communication and asset management by collecting the data those functions require using high speed time synchronized measurement within a substation. The design of the device has been guided by the IEC 61850 standard for communication and interoperability of substation automation devices. Protection functions are organized as individual application packages which means a new protection application can be added later while the device is still installed, without any hardware changes. The available applications include protection for overhead lines and cable feeders in distribution networks, line distance protection, power transformer protection, asynchronous machine protection and bus bar differential protection. The CPC device integrates functionality for circuit breaker control via the web-browser based HMI (WHMI) or by means of remote controls. The device continuously measures the phase currents, the symmetrical components of the currents, the residual current and residual voltage, the phase voltages, the voltage sequence components and the frequency based on the received process bus measurements. The device also calculates the demand value of the current over a user-selectable, pre-set time frame, the thermal overload of the protected object, and the phase unbalance based on the ratio between the negative-sequence and positive-sequence current. Furthermore, the device offers three-phase power and energy measurement including power factor. The measured values can be accessed remotely via the communication interface of the device. The values can also be accessed locally or remotely using the WHMI. Additionally, the CPC unit monitors the power quality functions like voltage variation, voltage unbalance, current harmonics, and voltage harmonics.

The CPC device is provided with a disturbance recorder featuring up to 160 analog channels and 512 binary channels. To collect sequence-of-events information, the device has a nonvolatile memory capable of storing 8192 events with the associated time stamps. The event log facilitates detailed pre- and post-fault analyses of feeder faults and disturbances. It also has the capacity to store the records of the 128 latest fault events. The records can be used to analyze the power system events. Each record includes, for example, current, voltage and angle values and a time stamp.

Merging Unit: The interface of the instrument transformers (both conventional and non-conventional) with the CPC unit is through a device called a Merging Unit (MU). MU is defined in IEC 61850-9-1 as interface unit that accepts current transformer (CT)/voltage transformer (VT) and binary inputs (BI) and produces multiple time synchronized digital outputs to provide data communication via the logical interfaces. IEC 61850-9-2LE or IEC 61869-9 defines a sampling frequency of 4 kHz (in 50 Hz networks) and 4.8 kHz (in 60 Hz networks) for raw measurement values to be sent to subscribers. Apart from acting as an interface unit between primary equipment and CPC device, the MU can also host I/O (input/output) to handle feeder based digital signals. It can communicate the digital status of primary equipment, like the circuit breakers, disconnect switches, and other isolation devices, to network devices as well as receive trip and open or close signals from an external unit.

Substation time synchronization: With Ethernet-based technology it is possible to achieve software-based time synchronization with an accuracy of 1ms quite easily, and without any help from HW. IEC 61850 standard refers this as the basic time synchronization accuracy class (T1). An older and more common protocol is the SNTP (Simple Network Time Protocol), which is suitable for local substation synchronization in relatively small systems. However, if the SNTP server is behind multiple Ethernet nodes, the latency increases, which reduces the accuracy of the time synchronization. Therefore, SNTP is not an ideal solution for system-wide implementation. Normally a GPS or equivalent time synchronization resource is required in every substation. IEEE 1588v2 and IEC 61850-9-3 deal with these issues and makes it possible to achieve a time synchronization accuracy of 1 µs. This is required for a process bus system like CPC.

Redundant communication: High availability and high reliability of a communication network are two very important parameters for architectures utilizing a CPC system. IEC 61850 standard recognizes this need, and specifically defines in IEC 61850-5 the tolerated delay for application recovery and the required communication recovery times for different applications and services. The tolerated application recovery time ranges from 800ms for SCADA, to 40µsec for sampled values. The required communication recovery time ranges from 400ms for SCADA, to 0 for sampled values. To address such time critical need for zero recovery time networks, IEC 61850 standard mandates the use of IEC 62439-3 standard wherein clause 4 of the standard defines Parallel Redundancy Protocol (PRP) and Clause 5 defines High-Availability Seamless Redundancy (HSR). Both methods of network recovery provide “zero recovery time” with no packet loss in case of single network failure.

C. CPC system design considerations

For risk mitigation it is extremely important to consider possibilities for redundancy. Also, in centralized protection the modifications to the protection device might cause downtime for the complete substation if the device needs to be taken out of use.

Perhaps the most obvious redundancy method is to duplicate the central device (Figure 3). This ensures that, for any CPC unit failure, there is still fully functional protection available. As the central protection devices can have identical configurations, the engineering and maintenance is still efficient. Also, during update procedures and testing, the redundant unit can handle protection while the other unit is out of service.
For completely new installations, this kind of duplicated central protection seems to be the optimal solution.

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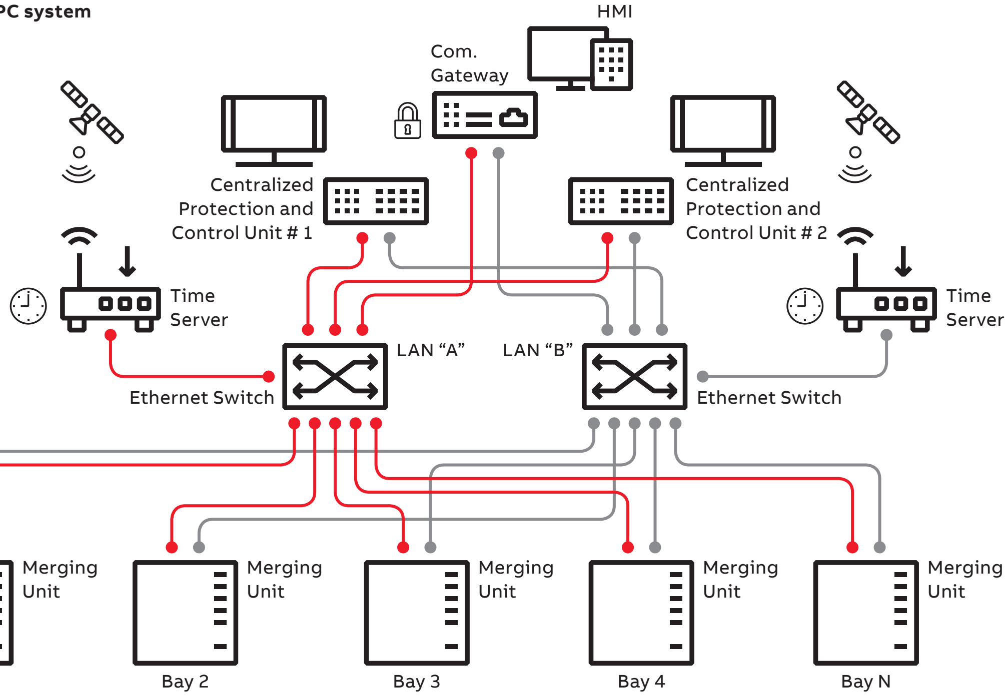
Figure 3: Redundant CPC system



IV. CPC system engineering

The process of engineering a Centralized Protection Scheme can be summarized as follows:
- Setting up a project
- CPC – Protection & Control Engineering
- Merging Unit Engineering
- IEC 61850 Engineering
  - GOOSE Engineering
  - Sample Measured Value (SMV) Engineering
- CPC – HMI Engineering (SLD)

A. Setting up a project

The first stage of CPC system engineering is the creation of a project. This is done using Protection and Control Manager software tool. The configuration tool is compliant with IEC 61850, which simplifies the IED engineering and enables information exchange with other IEC 61850 compliant tools. The hierarchical presentation model that reflects the real system topology enables efficient viewing and editing of the power system information.

The process can be divided as follows:
- Building the plant structure
- Creating substation level objects
- Creating voltage level objects
- Creating bay level objects
- Creating IED(s)

Substation level IED is added to the project, and then the voltage level is added. After this step, CPC device is added under the substation level as shown in the Figure 4.

B. CPC – Protection and Control engineering

Setting up a controls and protection in CPC is the next step. Various protection function blocks such as 50P, 51P, 50N, 51N are added as per the project requirement. The PAC engineering is performed by a step-by-step process using the Application Configuration Tool (ACT), which is an intuitive graphical tool that allows adding, deleting, and connecting the PAC function blocks. Figure 5 shows protection tab of feeder PM132 configured in the CPC device. The protection and control functions for other feeders PM133, PM134 and PM135 are configured in a similar fashion.

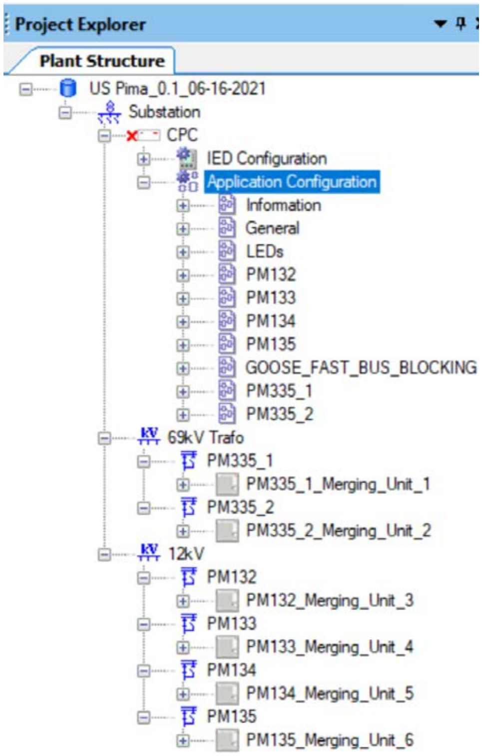


Figure 4: Plant structure view with CPC device and MU

C. Merging Unit engineering

As explained in the previous section, the role of MU is (a) to collect analog signals and send it to CPC device via SMV and (b) to host I/O and send the status of CB to CPC unit and receive protection trip, CB open and close commands from CPC device.

Steps for setting up the MU in the plant structure:
- To setup the MU, bays and voltage levels are added under the substation level. The power transformer has two MUs – one each on the high and low side of the transformer, and 12 kV feeder level has four MU. (Figure 4)
- The dedicated substation MU used in the project comes preconfigured with SMV sending block. GOOSE sending and receiving function blocks are added as per the project requirement. Digital I/O, LED, master trip, CB control configurations are completed as shown in the Figure 6.
- Parameters for each MU is set using the Parameter Setting Tool (PST).
- Configuration of GOOSE receive connections and physical hardware inputs and outputs are done using Signal matrix tool (SMT) – Figure 8.

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Figure 5: Protection configuration of feeder PM132

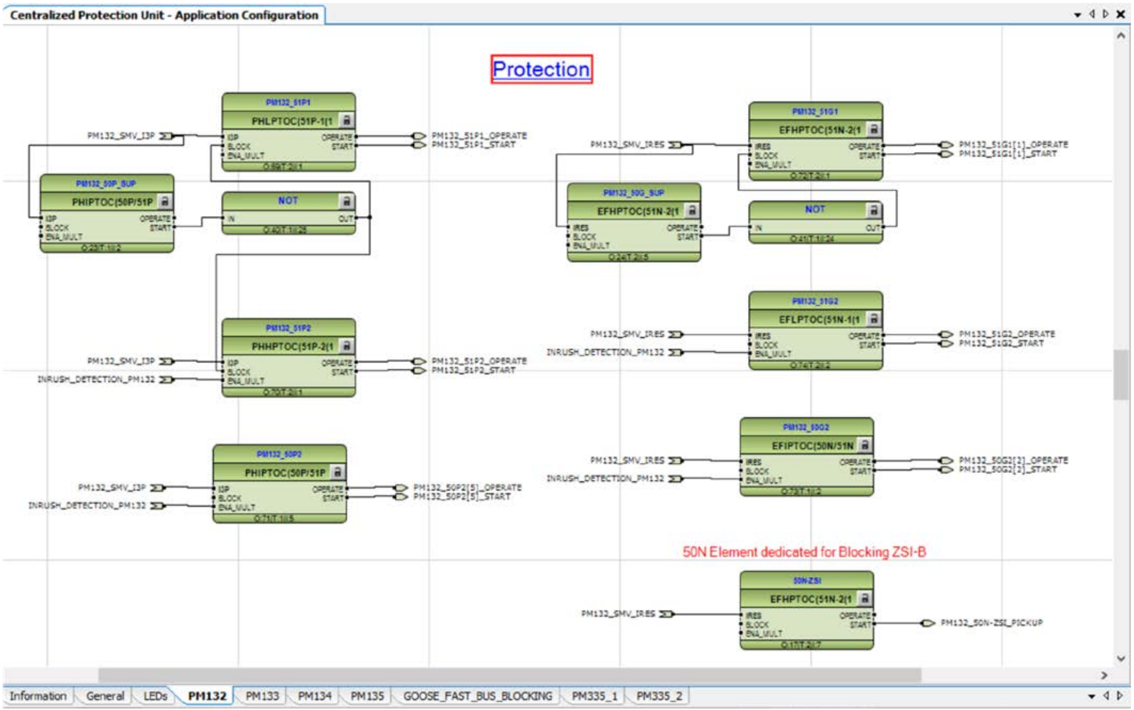

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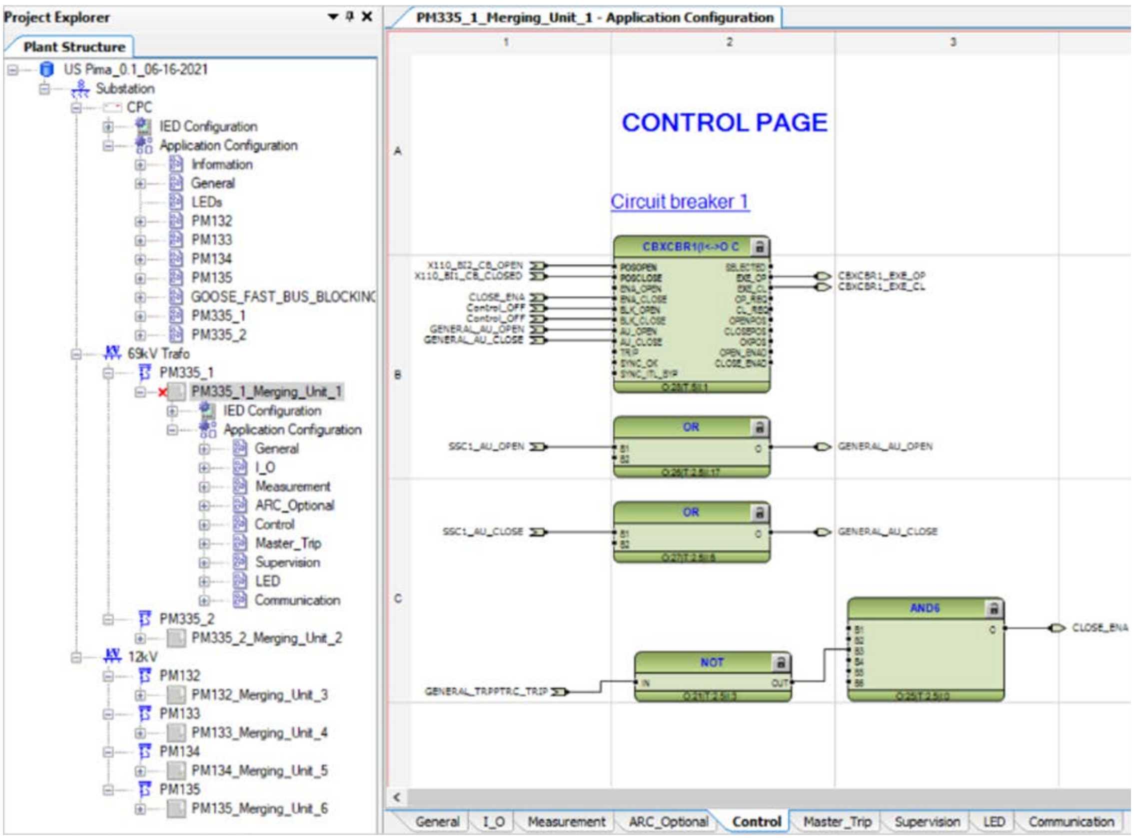
Figure 6: CB control configuration of transformer HV side MU PM335-1



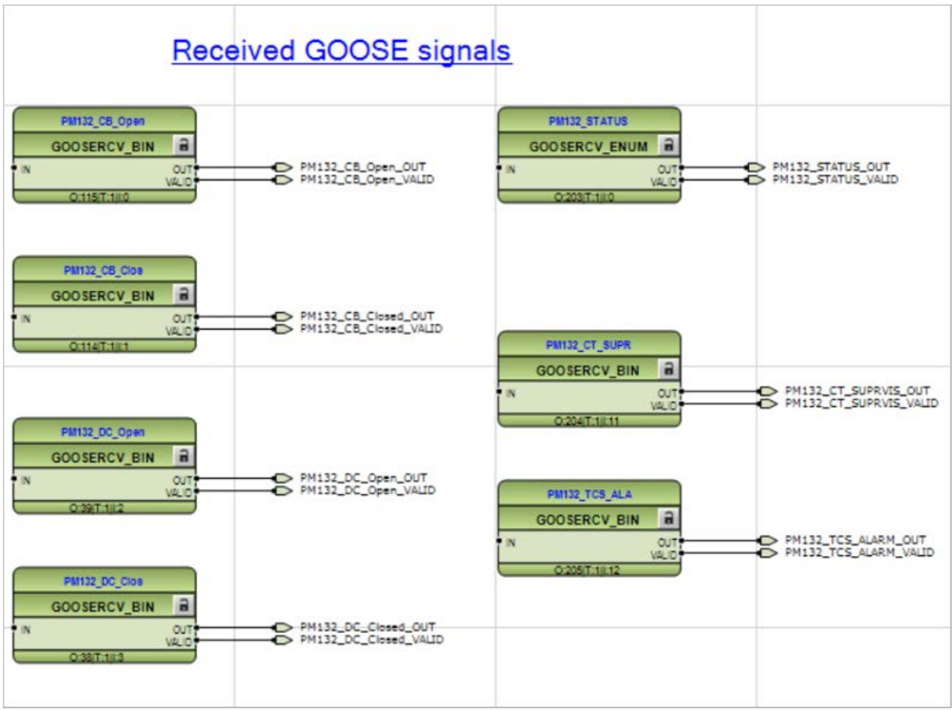


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Figure 7a: GOOSE receive configuration in PM132

D. IEC 61850 engineering

The most significant feature of IEC 61850 standard is that it is not limited to communication protocol, but has an organized framework for establishing substation engineering, maintenance, and operation. It is a standard for modelling the system. The data is communicated according to the station bus and the process bus sections of the standard. The CPC system utilizes MMS to communicate device status, GOOSE messaging to transfer breaker status, trip and close commands and Sampled Values for real time analog value communication. The communication engineering is accomplished using the built-in IEC 61850 engineering tool in the programming software.

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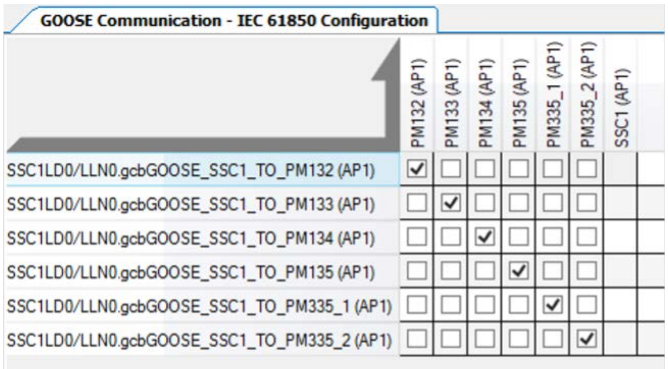
Figure 7b: Routing of GOOSE signals from CPC device to MU



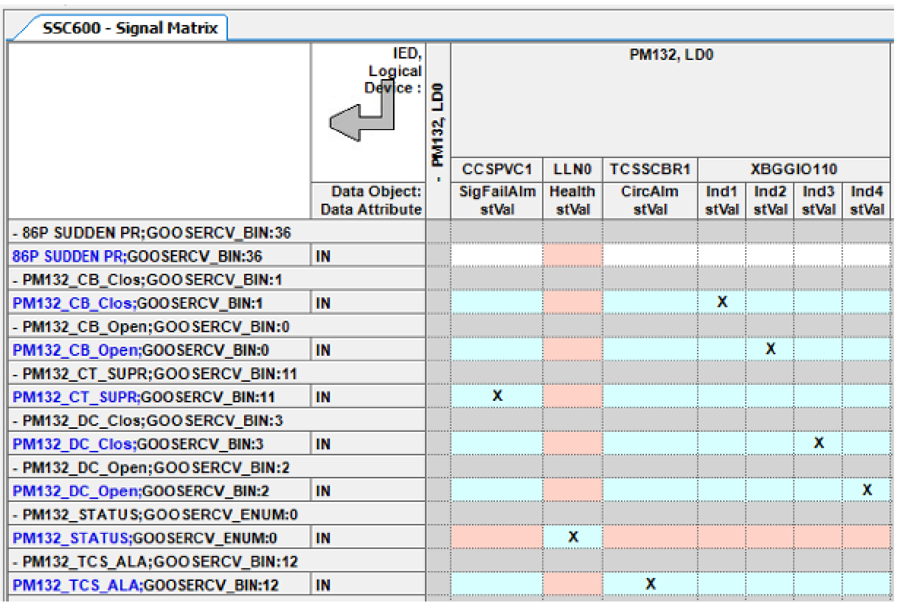
D.1. GOOSE engineering

GOOSE messaging is used for fast and direct data transfer of information from CPC to MU and vice versa. Breaker status, protection trip, open and close commands are sent via GOOSE messages as shown in the figure 7a. The subscription of the GOOSE datasets by the respective MU is configured as shown in figure 7b.

The GOOSERCV function block is configured for receiving the signals sent from CPC. The next step is to connect the GOOSE inputs to the process using SMT as shown in Figure 8. Setting up the MAC address, technical key, and the IP addresses, are the next steps for publishing (sending) and subscribing (receiving) the information. VLAN-ID needs to be configured to facilitate transfer of the signals securely and efficiently.

D.2. SMV engineering

SMV Sender: SMVSENDER function block sends the sampled values from the MU to CPC device. Upon adding SMVSENDER block to ACT, sampled value control block (SVCB) and the data sets are added by default. These datasets comprise of four currents and four voltages with quality attributes as defined by IEC 61850-9-2LE. MAC address and Sample value ID (SV ID) of the SMVSENDER block is to be set.



SSC600 - Signal Matrix

IED, Logical Device : / Data Object: Data Attribute		- PM132_LD0	PM132, LD0 CCSPVC1 SigFailAlm stVal	LLN0 Health stVal	TCSSCBR1 CircAlm stVal	XBGGIO110 Ind1 stVal	Ind2 stVal	Ind3 stVal	Ind4 stVal
- 86P SUDDEN PR;GOOSERCV_BIN:36									
86P SUDDEN PR;GOOSERCV_BIN:36	IN								
- PM132_CB_Clos;GOOSERCV_BIN:1									
PM132_CB_Clos;GOOSERCV_BIN:1	IN					X			
- PM132_CB_Open;GOOSERCV_BIN:0									
PM132_CB_Open;GOOSERCV_BIN:0	IN						X		
- PM132_CT_SUPR;GOOSERCV_BIN:11									
PM132_CT_SUPR;GOOSERCV_BIN:11	IN		X						
- PM132_DC_Clos;GOOSERCV_BIN:3									
PM132_DC_Clos;GOOSERCV_BIN:3	IN							X	
- PM132_DC_Open;GOOSERCV_BIN:2									
PM132_DC_Open;GOOSERCV_BIN:2	IN								X
- PM132_STATUS;GOOSERCV_ENUM:0									
PM132_STATUS;GOOSERCV_ENUM:0	IN			X					
- PM132_TCS_ALA;GOOSERCV_BIN:12									
PM132_TCS_ALA;GOOSERCV_BIN:12	IN				X				

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Figure 8: Connecting the received GOOSE signals in Signal Matrix Tool

SMV Receiver: Role of SMVRECEIVE function block is to –

1. Receive the SMV stream sent by the MU
2. Perform the supervision for the sampled values and to connect the received analog inputs to the application

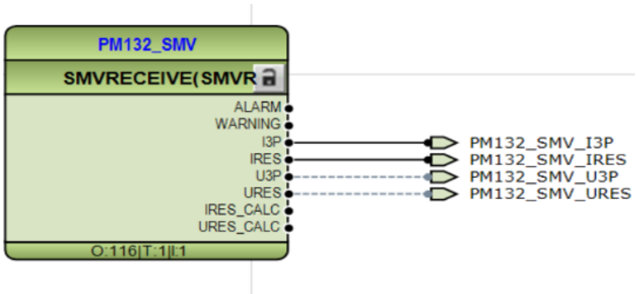

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Figure 9: SMV receive function block in CPC device

SMVRECEIVE block has output signals for phase currents, phase voltages, residual current and residual voltages. These output signals are connected to the protection and measurement functions of the respective feeder in the CPC device. SMVRECEIVE function block SV Identifier is set identical to the respective SMVSENDER SV Id.

Time synchronization: Precise time synchronization is very important for communication between MU and CPC device. IEEE 1588v2 PTP profile according to C37.238-2011 is typically selected to provide the most accurate and reliable time synchronization. It is important to note that some network routers can block 1588 traffic, and therefore it should be verified that all devices using 1588 time synchronization are utilizing the same master clock.

E. CPC – HMI engineering

WHMI is the control and visualization tool for controlling the MU and CPC and get a visual representation. To provide encryption and secure identification in the communication to the WHMI, the device supports HTTPS protocol. The CPC device is equipped to display the following via its WHMI.

- Single line diagram
- Programmable virtual LEDs and event lists
- Parameter settings
- Measurement display
- Disturbance records (DFR)
- Fault records
- Phasor diagram
- System supervision
- Report summary

The substation single-line diagram in the CPC device is designed using the built-in Graphical Display Editor (GDE) tool in the programming software. The HMI pages are handled according to rules.

- The CPC device supports single-line diagram for a substation up to 20 bays.
- Measurements and the single-line diagram can be displayed on the page in any possible order and placement.
- All symbol objects, for example apparatus and measurement, on the HMI page must be linked to the correct function block in the application configuration to present the correct process values.

Fully engineering HMI view of Pima substation – Bay 3 is shown in Figure 13.

V. Installation, testing and commissioning

A. Installation

The CPC system was set up in a non-redundant, monitoring only configuration (Figure 10), to assess its capabilities and performance. The CPC device, six supporting merging units, and a network switch were installed in a single rack-mount panel within SRP's Pima Substation, Bay 3 (Figure 11a, 11b, 12a, 12b). The pilot system did not use IEEE 1588 clock. However, the merging units and the CPC were time synchronized utilizing the built-in best master clock algorithm. This is a 69 kV single bus substation, which is typical for SRP, connected to multiple 69 kV lines and feeding a pair of 12 kV residential distribution bays. The pilot devices were placed, electrically in-line with their present standard protection and control system, which they refer to as Integrated Protection and Control System (IPACS), now on its third major revision (Figure 1). This system is made up of two redundant microprocessor relays (11B, 87T), a power quality meter (PQM), and transformer protection and control (98T, 74T).

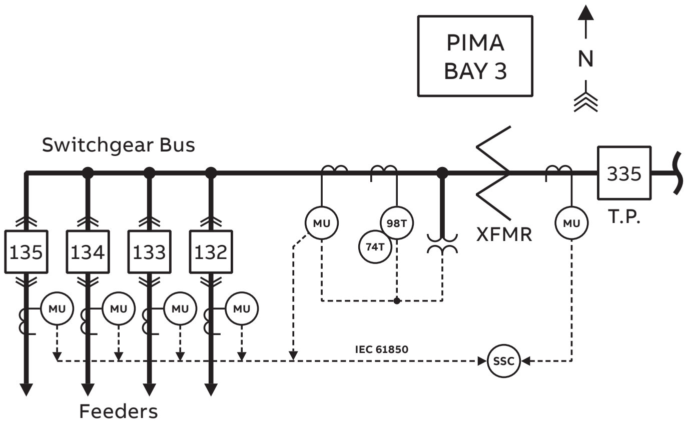

Figure 10: Pilot CPC system, non-redundant monitoring only

CPC panel

Fig.11a: Front top view

Fig.11b: Front bottom view

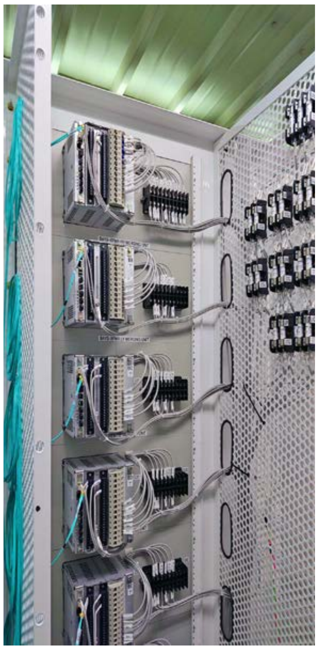

Fig.12a: Back top view

Fig.12b: Back bottom view

Parameter settings for the CPC device: The settings developed for the CPC were updated to match the standard IPACS devices, to provide a direct comparison in performance. This included the protection and control functionalities listed within Table 2. Event logging and disturbance recording were also enabled for all associated protection elements and communications (for example, sampled value streams).

The CPC has other protection functions and settings capabilities, some of which are discussed within Section IX. Next Steps.

Function	How is it used?	Settings	Number of instances required
Transformer Differential (87R/87U)	Trips/blocks closing on T.P. and all feeder breakers (LO)	32% restrained, 1000% unrestrained differential pickup	1
Sudden Pressure Device (86P)	Trips/blocks closing on T.P. and all feeder breakers (LO)	Monitors transformer's on-board sudden pressure device (c-form contact provided to inputs, 1 N.O. and 1 N.C. contact)	2
Transformer Low-Side Breaker Failure (50BF)	Trips/blocks closing on T.P. and all feeder breakers (LO)	0.15*In peak-to-peak pickup, 15 cycle timer	1
Transformer Phase Time Overcurrent (51P)	Trips feeder breakers for transformer overload	140% FLA, curve coordinated with transformer damage curve	1
Transformer Ground Time Overcurrent (51G)	Trips feeder breakers for transformer overload	100% ground conductor limit, curve coordinated with feeder OCs	1
Underfrequency (81)	Trips feeder breakers (manual reset)	Levels coordinated with WECC SILTP	1
Undervoltage (27)	Trips feeder breakers	62.5% V_{nom}, 10s pickup, 5 s reset	1
Bus Differential (87B)	Trips/blocks closing on T.P. and all feeder breakers (LO)	30% restrained differential pickup (originally setup as a zone blocking scheme)	1
Feeder Phase Time Overcurrent, Normal (51P1)	Trips associated feeder breaker	100% of feeder conductor limit, curve coordinated with downstream fuses	4
Feeder Phase Time Overcurrent, Cold Load (51P2)	Trips associated feeder breaker	100% of feeder conductor limit, 15 x normal phase time dial	4
Feeder Ground Time Overcurrent, Normal (51G1)	Trips associated feeder breaker	50% of ground conductor limit, curve coordinated with downstream fuses	4
Feeder Phase Time Overcurrent, Cold Load/Ground Disabled (51G2)	Trips associated feeder breaker	85% of ground conductor limit, 1.2 x normal ground time dial	4
Feeder Breaker Failure (50BF)	Trips T.P. and all feeder breakers	0.15*In peak-to-peak pickup, 15 cycle timer	4
Feeder Reclosing (79)	Re-closes feeder following overcurrent	1 shot at 1 second	4
Feeder Restoration (79AUTO)	Re-closes feeder following UV or UF trip	Staggered closing of all feeders, 5 seconds	4

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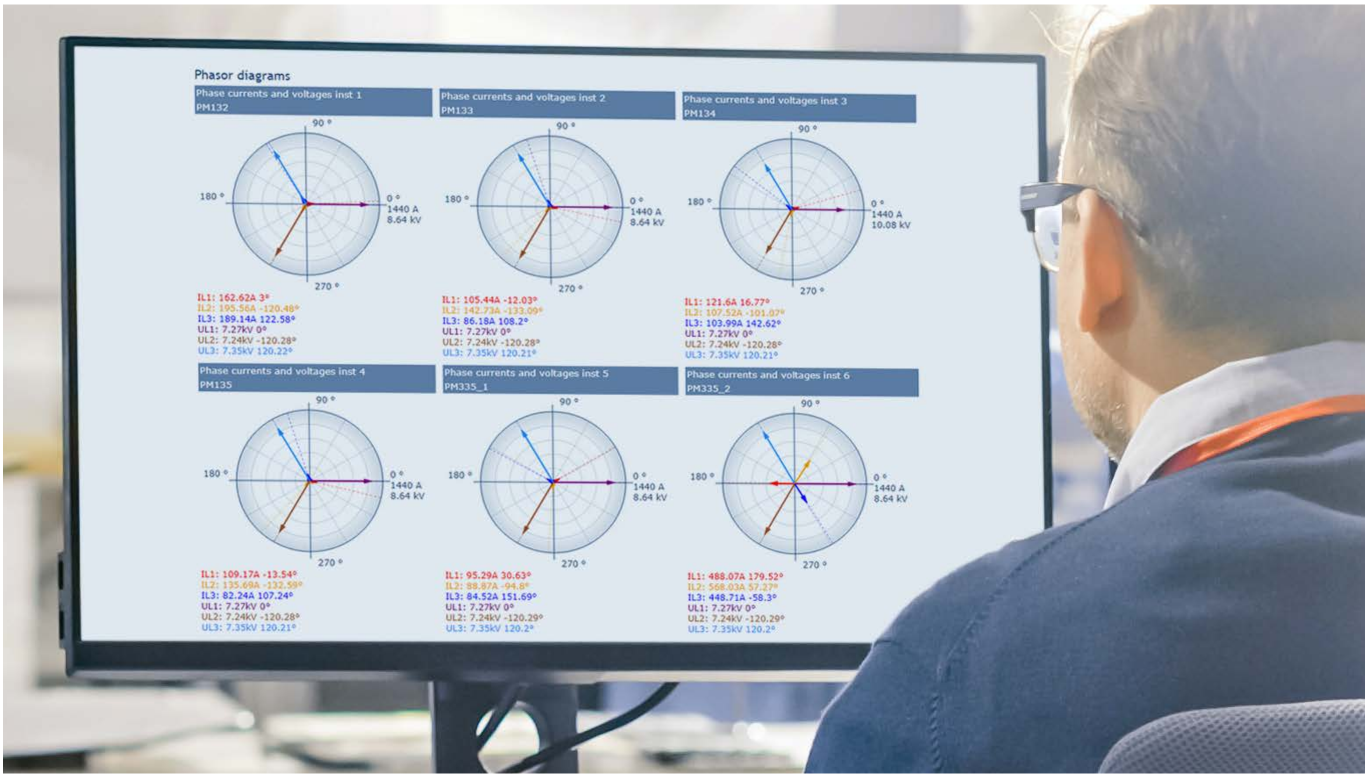
Table 2: Standard IPACS and CPC settings for SRP Pima Bay 3



B. Testing

Typical testing of an SRP relaying system involves full schematic checks of inputs, outputs, and analogs, testing of all logical elements, and verifying system integration with Operations. The installation of this CPC pilot project was rushed in order that it might occur with the already scheduled substation upgrades, thus lab checks were limited to cybersecurity scanning only. Additionally, the scheduled on-site joint manufacturer and customer testing that was arranged to occur in the weeks that followed commissioning, happened to coincide with the beginning of the COVID-19 pandemic. Difficulties specifically related to this are elaborated on in Section VI. Thus, the system was placed in-service without the rigor that was desired.

In practice, testing of a traditional PAC system and a CPC system is the same throughout the commissioning stage. As described in previous sections a CPC system operate based on the Sampled Values received from the MUs. The circuit breaker (CB) status information (52a, 52b contacts) and the CB trip and close signals are transmitted as GOOSE messages. During the periodical maintenance testing stage, or when changes are made to the system that do not affect the control wire and communications of the system, simulation of the Sampled Values and GOOSE messages could be performed. For example, when adding new protective functions as a result of system changes.

Most of the relay test set manufacturers have introduced test sets with GOOSE and Sampled Value simulation capability. The test set may be connected to the network switch from where all the protection applications for each feeder configured in the CPC can be tested. The test process allows CPC to be put in test mode. The test set injects the operating quantities in the simulation mode for each feeder, one at a time. Under this condition the CPC ignores the real MU values. Once a feeder is tested, the SV ID address of the test set is changed to that of the next MU for testing its corresponding feeder. This process is continued till all the feeders configured in the CPC are tested. CPC approach provides tremendous time saving from the wiring and connection of the test set as the test set up remains unchanged irrespective of which application or feeder is tested on CPC. Periodic and maintenance testing could be done this way if allowed by the regulating authority. Further, the test process can be automated taking advantage of IEC 61850 standard and test set capabilities which allow uploading and linking of parameter settings, GOOSE and Sampled Values into the test plan [3] [6]. Alternately, each feeder can be tested by putting both the MU and the CPC in the test mode. In this case the secondary injection of analog quantities is done at the MU. When the CPC is in the test mode, it ignores the real Sampled Values from other MUs. This method allows the entire path to be tested – the MU, communication channel and the CPC operation. This method is similar to testing the traditional PAC system.

C. Commissioning

The circumstances surrounding the timing of the system going in-service limited the commissioning activities as well. Load reads were taken on the systems though, within the vendor developed single line diagram (Figure 13), and the built-in phasor diagrams (Figure 14), both of which are available via the CPC's WHMI. These values were matched up with the standard IPACS devices for accuracy. Additionally, the programming software PCM600 has an embedded "online debugging" tool (Figure 15). This tool allows monitoring of the logic signal flow from the input of a function block to the output of a logic scheme. This facility greatly helped in debugging and troubleshooting of the logics during the commissioning process.

The restrictions and shutdowns associated with the COVID-19 pandemic began at the same time as testing and commissioning activities were taking place for the standard IPACS and CPC installation. Therefore, the planned, rigorous assessment of the connections and associated logic settings of the CPC were postponed indefinitely. Monitoring became much more challenging than originally anticipated, even though the pilot site was chosen as one close to the office, for ease of access. Therefore, with the system now in-service, the remote connectivity became infinitely more important.

Cybersecurity scanning had been completed, for company compliance purposes, and therefore interactive virtual access was allowed. However, this was the first time SRP had generated their own PAC-related self-signed certificate authority (CA) certificate and private key, which was required for the new device. It took some time to go through the proper channels, but the files were eventually approved and applied. The next step was connecting the CPC server to two separate networks. Locally, the CPC was communicating via a LAN to the individual merging units. But remote connectivity was only allowed via hypertext transfer protocol secure (HTTPS) on SRP's operations network. Initially, having separate ports on different subnets was not possible. But the manufacturer did provide a firmware update available that would make this possible. By Q1 2021, full remote visibility and control of the CPC device, its settings, and the WHMI dashboard were available to remote users.

Figure 13: CPC WHMI SLD for SRP Pima Bay 3

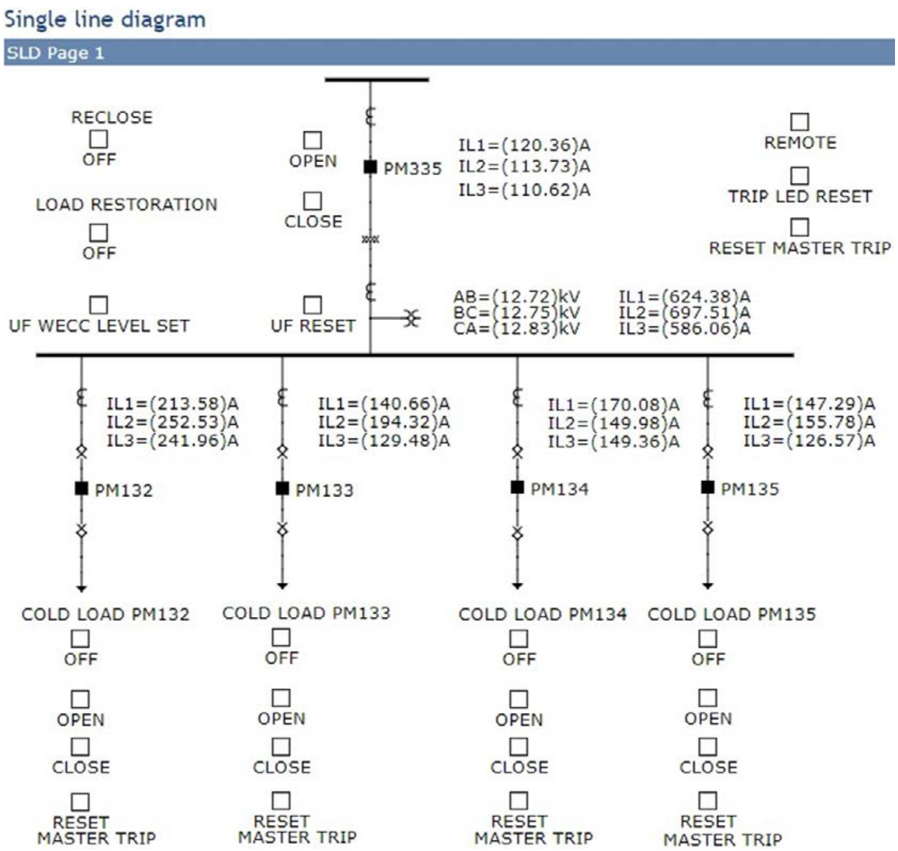


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Figure 14: CPC built-in phasor diagram

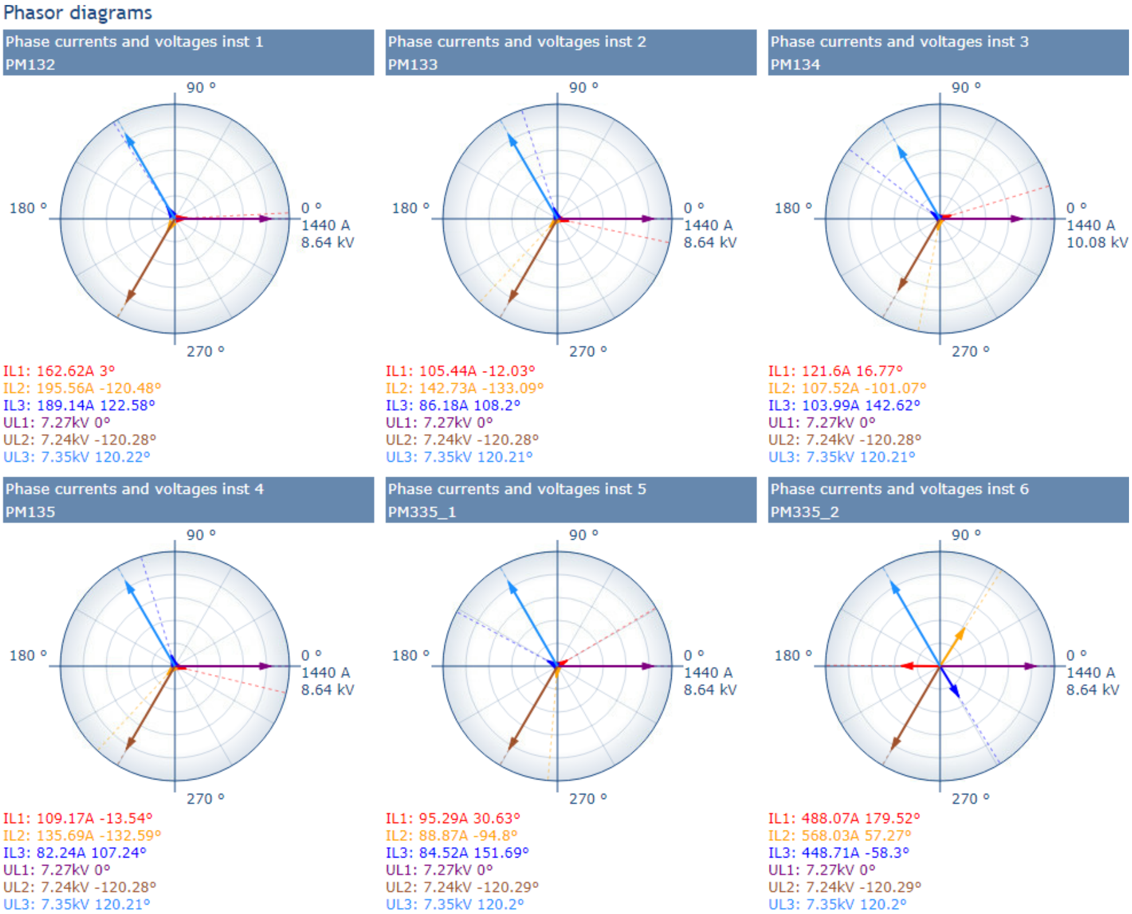

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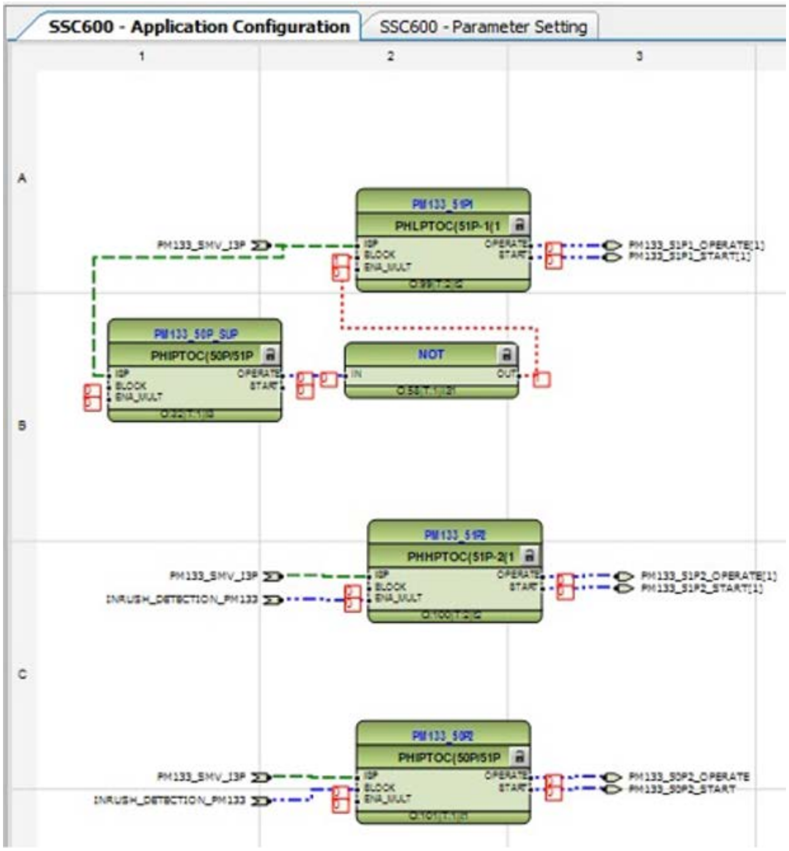
Figure 15: CPC system – Online debugging tool



VI. Performance evaluation and lessons learned

As stated earlier the onset of the pandemic and the shutdowns that followed limited the pre-commissioning tests conducted. But, of course, full schematic testing of the CPC system would be ideal. This will help identify any system setting errors upfront and help save time spent on trouble shooting. For example, the MU analog input (CT, PT) settings should match with the SV receiver function block settings in the CPC device. Otherwise, there will be a difference in the current send by the MU and received by the CPC unit.

It is very important to know how the device is interpreting waveforms. The measurement mode for each setting may be based on either peak-to-peak or RMS methods, and therefore the desired pickup and operate levels must be carefully scrutinized.

CPC Comparison with Standard IPACS:
There was a feeder trip that occurred on 07/16/2021, at approximately 10:43:40AM. The waveforms were captured by the IPACS standard relaying (Figure 16), which tripped and successfully reclosed. The CPC system also captured the event (Figure 17). These two captures were evaluated using the same event viewing software, where the differences in the IPACS' 2 kHz sampling and the CPC's 4.8 kHz (68150-9-2 LE standard rate) become more obvious. The increased frequency shows transients in the B- and C-phase currents that are otherwise invisible. Other notable differences include the lack of tripping by the CPC, the time stamp difference between the systems (as these two systems are not synchronized with each other), and the inversion of the neutral current between the two. The lack of tripping of the CPC was due to an incorrect setting on a supervisory current element for the normal time overcurrent trip. This has been corrected following the event.

The time difference between the two systems is approximately 500ms, with the CPC lagging the IPACS relaying. Both are synced to SNTP, but the IPACS relaying was manually compared to a GPS synced power quality meter (PQM) that is part of the standard installation. This device captured the same fault event as well and revealed that the NTP-synced IPACS relays were only lagging by approximately 5 ms. SRP plans to incorporate IEEE 1588 PTP clock in the CPC system to correct the time synch mismatch.

The neutral current is measured by the IPACS standard devices, with a dedicated current input. In the CPC system the neutral current is not wired to the MU, being a pilot system. CPC device is calculating the neutral current and has determined it to be in-phase with the A-phase current. It was verified by independent testing that if neutral current is wired to MU, it will then be 180 degrees opposite with A-phase current, as per the standard convention. The residual current in CPC is calculated from the phase currents according to the equation Io = - (IA+IB+IC).

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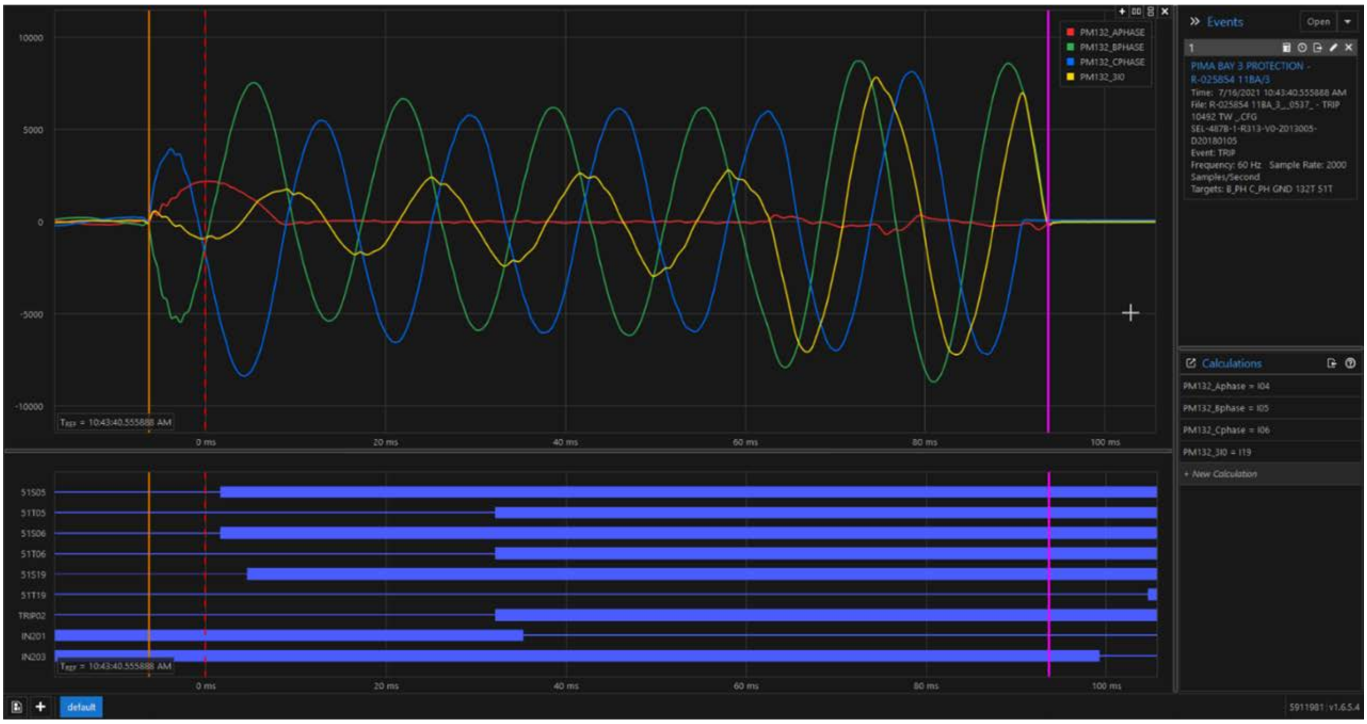
Figure 16: IPACS standard relaying, feeder trip for BCG fault on 7/6/21



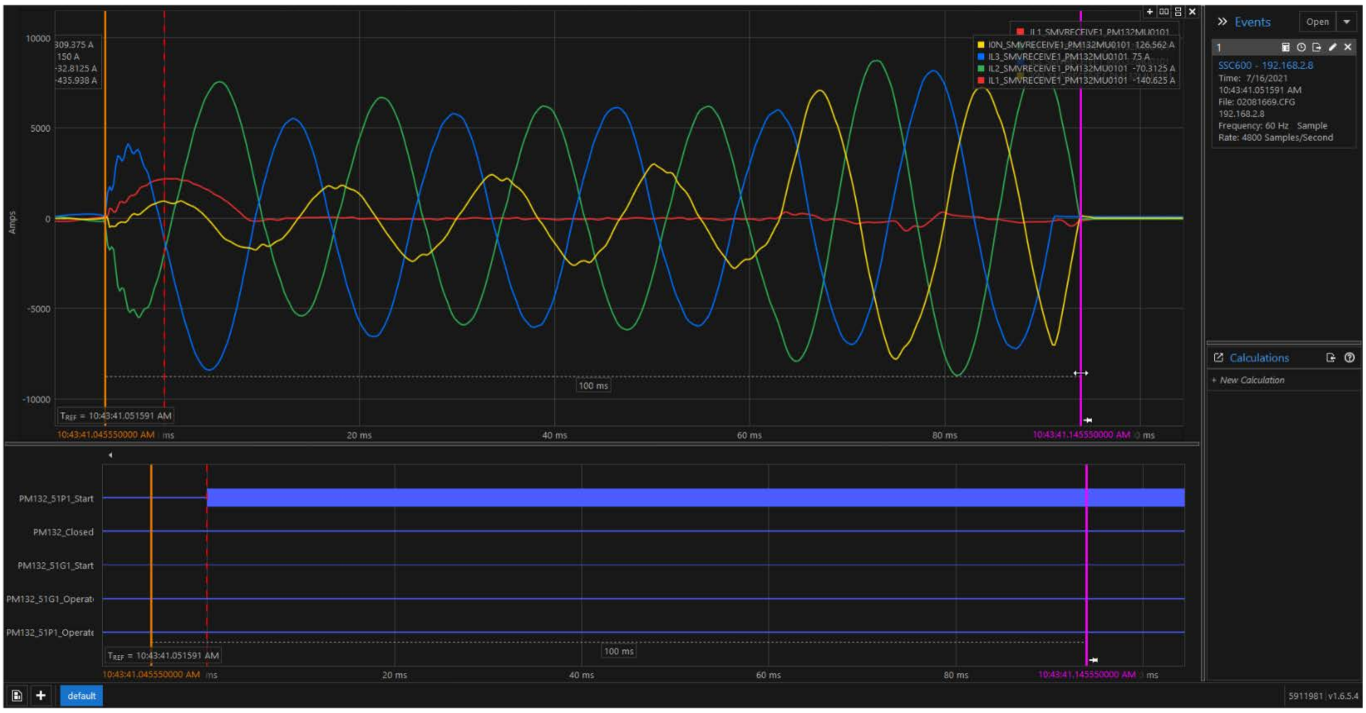


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Figure 17: CPC event, feeder trip for BCG fault on 7/6/21

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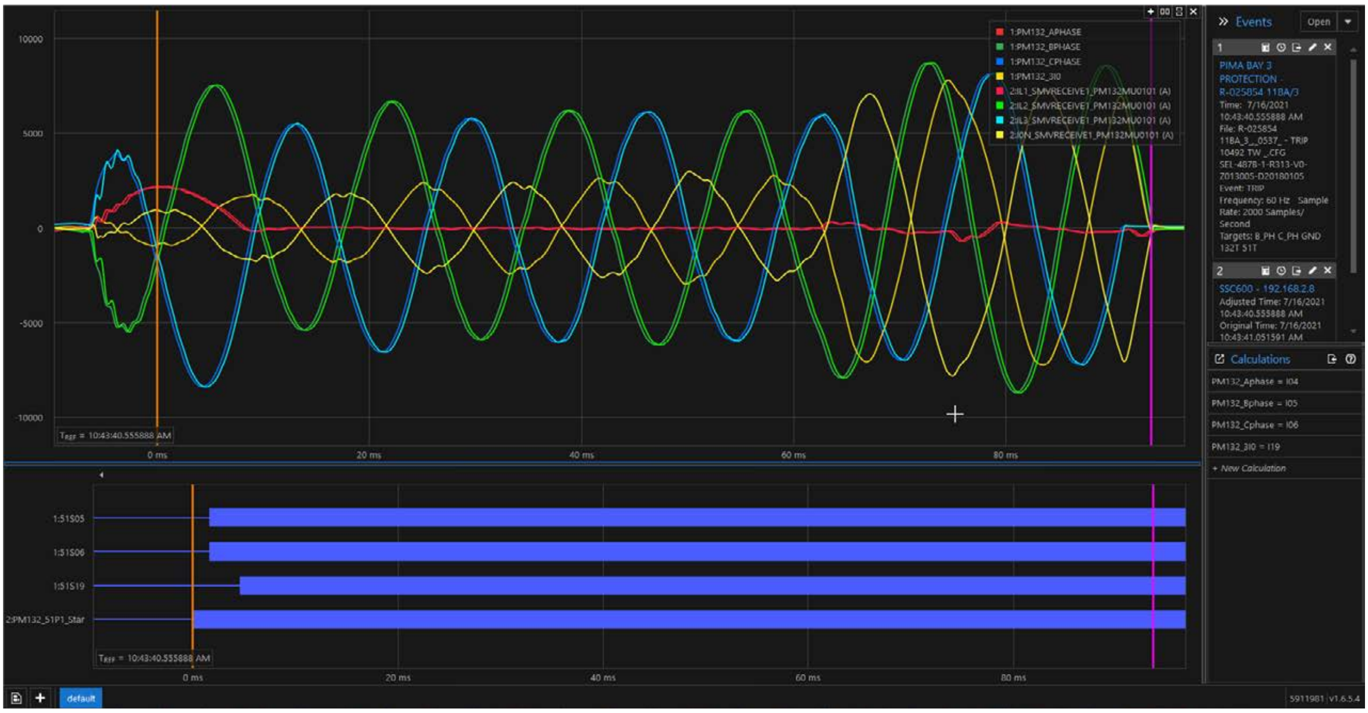
Figure 18: IPACS standard and CPC events, overlaid



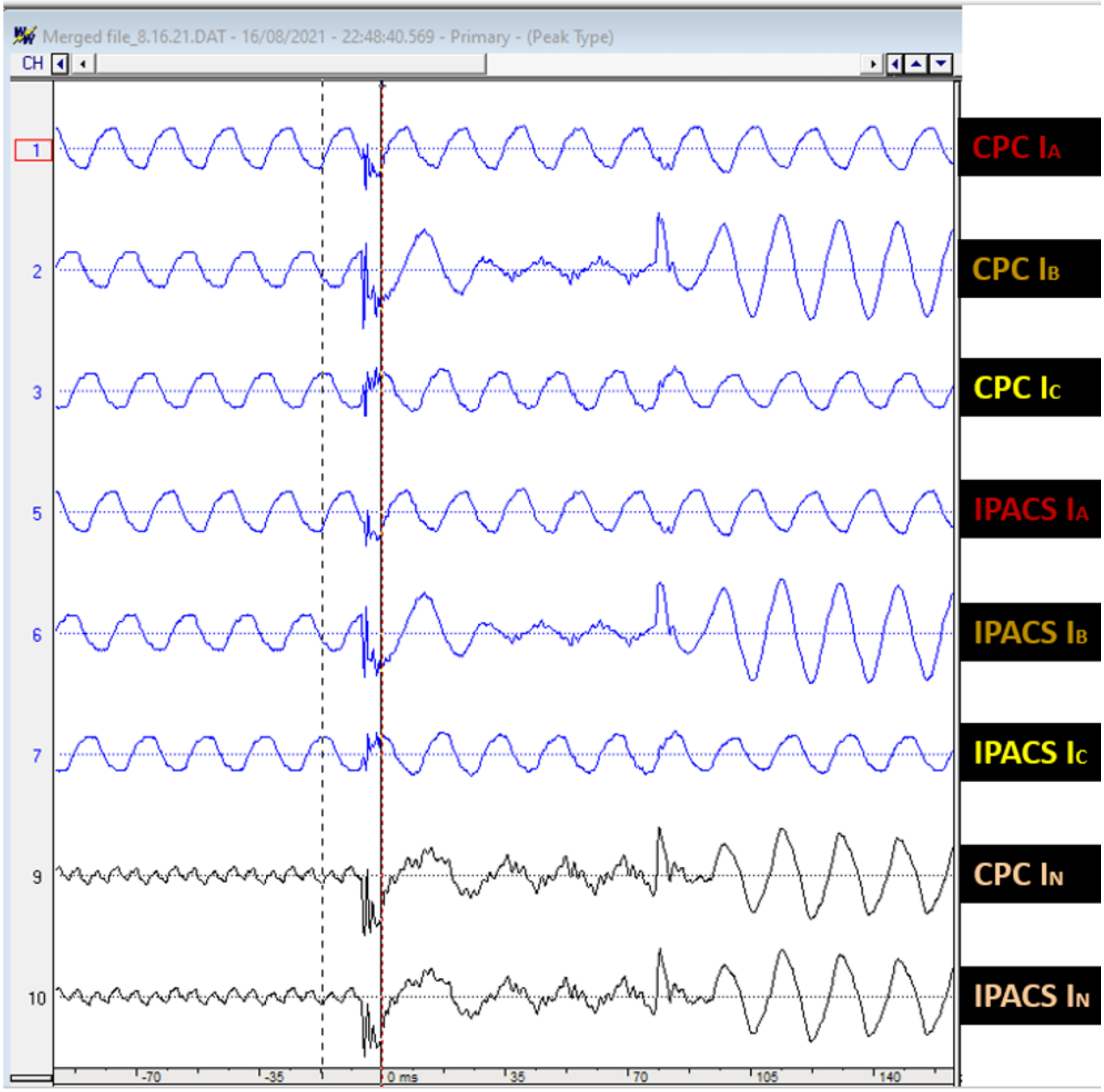


Figure 19: Merged view of waveforms from CPC and IPACS during the protection trip on 8/16/21

There was another system fault event on 8/16/21. The waveforms captured from CPC device and IPACS are shown in Figure 19. The top three waveforms are from the CPC and the next three are from the IPACS. The bottom two waveforms are the calculated neutral currents from CPC and IPACS. We can see that CPC system measuring the currents via the sampled values are identical to the currents measured by the directly wired IPACS measurements. Both the CPC and IPACS tripped as intended.

VII. Next steps

Moving forward there will be additional features added to this CPC device. Addition of a new protection application is rather simple as the software package can be loaded on the existing device without any hardware change.
True bus differential protection is already available from the manufacturer. Zone back blocking was originally enabled to mimic the functionality of a switchgear bus differential. However, activating the new differential functionality will provide additional speed and security.

Precision time protocol (PTP) timing will be added to the system as well. Originally, only simple network time protocol (SNTP) was provided to the CPC, with the merging units running freely, but synchronizing to each other utilizing the built-in best master clock algorithm. The added accuracy of PTP time will allow stability in differential protection and additional precision in the recording and reporting functionality.

In order for this system to be activated on an in-service distribution bay at SRP, redundancy capabilities will need to be evaluated beforehand. Parallel redundancy protocol (PRP) capability is already present within the CPC device and would provide a seamless failover networking mode.
It would be ideal to have redundant CPC devices and merging units as well, but this increases the device count to fourteen, and that is significant for this relatively small station configuration of a transformer and four feeders. It would certainly help if merging units were more cost-effective at present so this ideal setup could become more feasible. To achieve this MU capable of publishing multiple sampled value streams shall be considered for future implementation.

Conclusion

Most intelligent electronic devices (IEDs) remain essentially static in terms of what can be programmed within, including those that support digital architectures, such as IEC 61850 station and process bus communications. This means there is an overall lack of capability for them to be updated and to incorporate new data, preventing them from being able to adapt to changes in the grid as they serve out their lifespan.
Yet, we are fully aware of the upcoming additions of highly concentrated and flexible loads, distributed energy resources, and transportation electrification that will inevitably result in a much more dynamic supply and demand of power flow. Therefore, PAC devices must become easier to install/service/replace, facilitate the relatively rapid evolution of algorithms and increase in data publishing and consumption, and be poised to integrate into multi-level wide-scale management systems.

The deployment of the CPC pilot system was a good first step for SRP in meeting their long-term objective of managing the assets more efficiently. Centralization of protection and control within a single device does represent an overall improvement in many areas and will be easier to manage moving forward. This system was validated to perform as intended during system fault conditions, and additional benefits from operation, maintenance, and life cycle management will be realized in the long run.
However, there is room for further improvements that can make deployment even simpler and provide additional future flexibility. The major challenges that are still being faced, even with modern, centralized PAC standards, are related to form factor and fixed functionality. The physical installation of relaying, control, and communications equipment remains extremely labor-intensive. Therefore, this is the major limiting element in productivity both on the capital and maintenance sides of the business. The CPC piloted by SRP points them in the right direction though, as the industry shifts towards software-defined (and ultimately, virtualized) systems.

VIII. References

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Acknowledgements
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IX. Biographies

Anthony Sivesind received his B.S. degree, as well as his M.S. degree, in electrical engineering from Arizona State University, with emphasis in mechatronics and alternative energy. He has 18 years of experience in the utility industry and has worked in a variety of roles during his tenure at Salt River Project, including designer, engineer, and project manager of major substation construction and transmission jobs, new protection and control initiatives, as well as standards development and implementation. He is presently an Executive Engineer in the Protection, Automation, and Control Strategy department, where he can focus on research and development initiatives to efficiently protect and control the grid, in support of SRP grid modernization.

Mr. Sivesind is a member of IEEE, and a licensed electrical engineer in the state of Arizona.

Joemoan (Joe) Xavier is currently the Global Product Manager for ANSI portfolio of ABB Digital Substation Products & Digital Systems. After receiving his B. Tech degree in Electrical & Electronics Engineering, he started his career as a relay engineer. He has over 28 years of experience with Power Systems protection and automation applications, business development and product management. Joe has authored, co-authored, and presented several technical papers on Protection, Automation & IEC 61850 applications and is an active member of IEEE PES Power System Relaying and Control Committee.

Chinmay Modak received his Bachelor of Engineering from Gujarat Technological University and M.S. degree from the State University of New York At Buffalo in Electrical Engineering with focus on Power System Engineering, and Power systems protection. Chinmay started working as a Protection Engineer after receiving his M.S. degree. He is currently working with ABB as a Relay protection / Application Engineer.

Abbreviations used

ACT	Application Configuration Tool
BI	Binary Input
CA	Certificate Authority
CB	Circuit Breaker
CPC	Centralized Protection and Control
CT	Current Transformer
DFR	Digital Fault Record
GDE	Graphical Display Editor
GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
HMI	Human-Machine interface
HSR	High-Availability Seamless Redundancy
HTTPS	Hypertext Transfer Protocol Secure
I/O	Input/Output
IED	Intelligent Electronic Device
IPACS	Integrated Protection and Control System
LAN	Local Area Network
LED	Light Emitting Diode
LO	Lock Out
MMS	Manufacturing Message Specification

MU	Merging Unit
MV	Medium Voltage
NTP	Network Time Protocol
PAC	Protection and Control
PQM	Power Quality Meter
PRP	Parallel Redundancy Protocol
PST	Parameter Setting Tool
PT	Power Transformer
PTP	Precision Time Protocol
RMS	Root Mean Square
SCADA	Supervisory Control and Data Acquisition
SLD	Single Line Diagram
SMT	Signal Matrix Tool
SMV	Sample Measured Value
SNTP	Simple Network Time Protocol
SV	Sampled Value
SVCB	Sampled Value Control Block
TP	Triple Pole Circuit Breaker
VLAN	Virtual Local Area Network
VT	Voltage Transformer

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