Case Study: Designing Centralized Protection and Control Systems for a Distribution Substation at Duke Energy

Stephen B. Ladd, Taylor I. Raffield, and Ethan Haithcox
Duke Energy

Jackson Fultz
Schweitzer Engineering Laboratories, Inc.
(formerly of University of North Carolina at Charlotte)

Arun Shrestha, Arunabha Chatterjee, and Priyanka Nadkar
Schweitzer Engineering Laboratories, Inc.

Presented at the
77th Annual Georgia Tech Protective Relaying Conference
Atlanta, Georgia
April 24–26, 2024

Previously presented at the
77th Annual Conference for Protective Relay Engineers at Texas A&M, March 2024

Originally presented at the
50th Annual Western Protective Relay Conference, October 2023

Case Study: Designing Centralized Protection and Control Systems for a Distribution Substation at Duke Energy

Stephen B. Ladd, Taylor I. Raffield, and Ethan Haithcox, *Duke Energy*
Jackson Fultz, *Schweitzer Engineering Laboratories, Inc. (formerly of University of North Carolina at Charlotte)*
Arun Shrestha, Arunabha Chatterjee, and Priyanka Nadkar, *Schweitzer Engineering Laboratories, Inc.*

Abstract—**This paper documents a collaborative effort between the authors' companies to design three separate centralized protection and control (CPC) systems for an existing distribution substation. The first uses a powerful but traditional approach with a microprocessor relay, the second a point-to-point (P2P) process bus architecture, and the third a process bus solution based on the IEC 61850 standard. CPC systems are compared against the existing protection and control (P&C) system using total device count, protection scheme unavailability, and protection system operation speed as criteria. The paper contains a discussion of the utility's perspective, exploring issues of potential benefits, design questions, and technical challenges.**

I. Introduction

A typical distribution substation consists of one or more step-down transformers that feed multiple feeders. In a traditional substation, each piece of primary equipment, i.e., the step-down transformer, bus, breaker, and feeder, is protected by a separate protective relay. These relays use copper cables to exchange analog and binary signals with primary equipment. A digital secondary substation employing a process bus solution uses fiber-optic cables to exchange data between relays in the control house and merging units (MUs) in the switchyard [1]. A process bus can be implemented using a point-to-point (P2P) architecture or IEC 61850 standard-based switched network architecture [2].

An IEEE Power System Relaying Committee Working Group K15 report defines a centralized protection and control (CPC) system as:

> a system comprised of a high-performance computing platform capable of providing protection, control, monitoring, communication and asset management functions by collecting the data those functions require using high-speed, time-synchronized measurements within a substation [3].

A typical CPC system consists of a computing platform, MUs, communications networks, and a time synchronization system. A CPC refers to the computing platform used in the CPC system for executing all protection, automation, control, metering, and other auxiliary functions. A CPC system aggregates all protection and control (P&C) applications in a few devices, with the goal of improving the reliability of P&C systems while potentially reducing design costs. Having fewer devices helps with hardware replacement and firmware upgrades.

This case study is based on a collaborative effort between the authors' companies. Using drawings and relevant documentation, three CPC systems were designed for an existing distribution substation. The first design uses a powerful microprocessor relay capable of providing all P&C functions for the entire substation and uses copper connections between primary equipment and the CPC system. The second CPC system was designed using a P2P process bus architecture, in which multiple MUs connect to the system using direct fiber-optic cables. The third CPC system uses an IEC 61850-based process bus architecture with multiple MUs, network switches, clocks, and CPC. To eliminate a single point of failure, two CPC systems were used for each design. Following the development of the three CPC system designs, the total number of devices used for each of the designs was tabulated. Using a fault tree analysis technique, the protection scheme unavailability of each design was evaluated. Communications schemes in a traditional substation, like fast bus tripping and breaker failure, were implemented in all three CPC systems and tested on actual hardware.

This paper includes the detailed design of three CPC systems. It lists the benefits and challenges of each design. Quantitative data on the total device count and protection scheme unavailability are provided. Test results demonstrating the performance of fast bus tripping and breaker failure schemes in traditional and CPC systems are presented. In addition to the results of the study, this paper provides a discussion of what the utility hoped to learn and the potential benefits of a CPC system. Comparisons to a traditional design are made, including issues such as redundancy and backup. As with the movement to any new form of technology, utilities have concerns and questions focused on the degree of centralization, unavailability, failure modes, and change management requirements for engineering and testing.

II. Overview of the Utility's Current Distribution Substation Protection

With the exception of the introduction of the microprocessor relay, protection on transmission to distribution (T/D) substations has remained relatively consistent for the past 30 years. Transformer bank panels have been designed with backup protection so that any single relay failure does not require the removal of the transformer from service. This approach typically uses a high-side overcurrent relay, a transformer bank differential, a low-side bus differential, a low-side overcurrent relay, and overcurrent protection on the transformer neutral. Distribution circuit exits have historically had a protection package for each circuit. An example one-line drawing illustrating the protection in a T/D substation can be seen in Fig. 1.

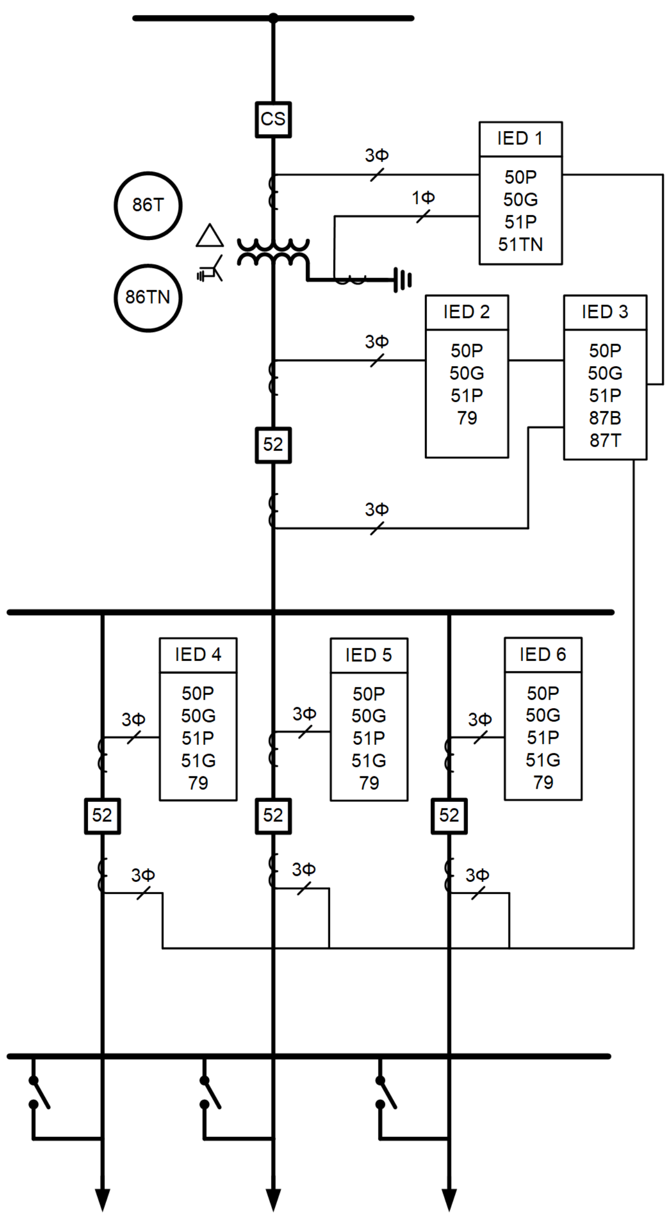

Fig. 1. Traditional one-transformer distribution substation.

This design allows for fast protection to be maintained within the substation. A transformer differential utilizes the bushing current transformers (CTs) on the high side of the transformer and a set of CTs on the load side of the low-voltage bus breaker. A bus differential is configured using the CTs on the transformer side of the low-side breaker and the CTs on the load side of the distribution circuit exit breakers. Typically, this style of design is implemented on two protection panels, a transformer bank panel, and a circuit exit panel. Historically, these panels utilized current test blocks, control handles, lockouts, and test switches.

The biggest disadvantage of this design is its dependence on one relay to provide both the transformer differential and bus differential protection. While the failure of this relay temporarily prevents fast protection within the substation, it does not prevent the continued operation of the substation or the ability to maintain substation protection.

While most T/D substations start off as a single transformer substation, they tend to grow with time. Transformers are replaced with larger ones as the substation grows, but more often, a second transformer bank and additional circuit exits are added to the substation. In many cases, these substations grow to three transformer banks and, in a few cases, even grow to four transformers.

The historical protection approach for a two-transformer T/D substation is illustrated in Fig. 2. The complexity of protecting and controlling a two-transformer T/D substation, as opposed to a one-transformer T/D substation, grows significantly. When a second transformer bank is added to a substation, a bus-tie breaker is installed between the two low-voltage buses. This bus-tie breaker allows for improved operating flexibility when performing maintenance on substation equipment but also allows for automatic bus transfers in the case of a transformer failure. Upon failure of a transformer, the low-side breaker and high-side circuit switcher (CS) will isolate the failed unit. A relay controlling the bus-tie breaker closes the bus-tie breaker, which picks up the load from the low-voltage bus of the failed transformer. The low-side protection on the good transformer has the additional functionality of making sure the additional load will not overload the remaining transformer. This is done through load-shed protection within the overcurrent relay on the low-side breaker. Additionally, Fig. 2 illustrates a few additional components found in T/D substations: a low-side auxiliary breaker, capacitors, and a high-side breaker with a swapover. Each of these components traditionally bring an additional relay. Both the swapover control and the capacitor require extensive programming, control logic, and a local operator interface.

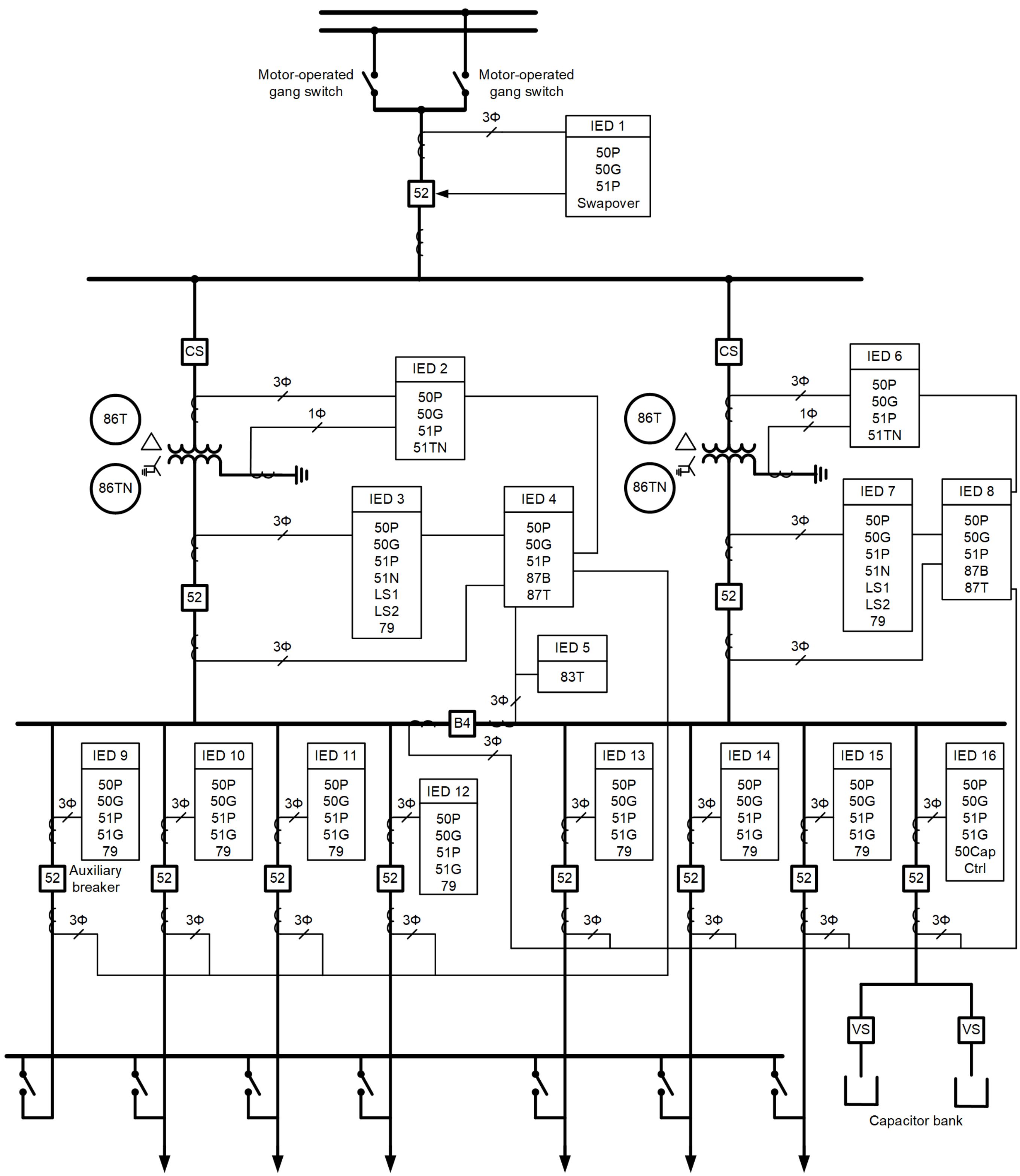

Fig. 2. Two-transformer distribution substation with bus-tie breaker, auxiliary breaker, capacitor, and high-side swapover.

III. Overview of CPC Systems

A CPC system:

> [is] comprised of a high-performance computing platform capable of providing protection, control, monitoring, communication and asset management functions by collecting the data those functions require using high-speed, time-synchronized measurements within a substation [3].

A CPC system is designed as a central brain of a substation and makes all decisions within a substation. In traditional substations, the decision making is generally distributed among various devices and engineering expertise is used to coordinate the devices. A CPC system aims to replace all the individual relays in a substation and act as a central hub for all P&C purposes.

A. Hardwired CPC System

A hardwired CPC system is an extension of the existing P&C design in a physically large and powerful relay. In this design, CTs, potential transformers (PTs), and switchgear signals are hardwired directly to the CPC, as shown in Fig. 3. Thus, the CPC has direct access to all the signals and can take direct control actions of all functions in the substation. All protection, control, monitoring, and other critical functions of the substation are executed in a single device. The advantage of this architecture is that it does not have any signal latency and thus can respond directly and quickly to any event. The design is simple, so it is suitable for small substations and industrial applications. It is well-suited for retrofit applications in which electromechanical relays or older generation relays with existing hardwired connections need upgrades. As this design uses fewer devices, fewer panels are required, and thus, a smaller control house is sufficient. Peer-to-peer communication (including relay-to-relay and MU-to-relay) is not required; hence, no extra networking infrastructure is needed. Due to limited inputs and outputs, this design might not scale up to incorporate substation expansion.

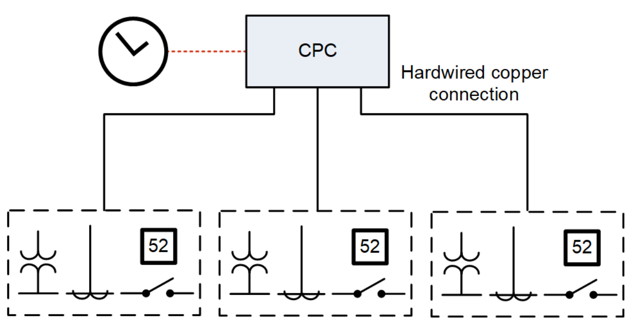

Fig. 3. Hardwired CPC system with copper connection to CTs, PTs, and switchgear.

B. P2P-Based CPC System

A P2P-based CPC system breaks up the traditional copper-based design into two parts. The data acquisition from the instrument transformers is carried out in a separate MU located next to the CT and PT cabinets in the switchyard. Depending on the size of the substation, multiple MUs might be needed. In a P2P-based CPC system, fiber-optic cables connect directly to MUs. Fig. 4 shows a schematic diagram of a P2P-based CPC system communicating with multiple P2P MUs. The complexity of designing a process bus network and configuring extra switches and clocks is removed as they are not required in this system. Instead, the CPC relies on its internal clock to time-align the data received from the multiple MUs connected to it and then uses the signals for executing protection functions. Hence, this design does not depend on external time for running local protection functions.

This design is well-suited for small- to medium-sized substations, eliminating the need to install copper cables between the switchyard and a control house. The advantage of this design over a hardwired CPC is its modularity and ease of expansion. If more bays are added, then MUs can be installed relatively easily next to the instrument transformer, which is then connected to the CPC. However, there is a limited number of communication ports in a CPC; thus, future expansion needs to be carefully considered during the design process. Use of fiber-optic cables enables monitoring capabilities. It is also much easier to swap out individual MUs for testing or replacement without having to decommission the CPC system. Compared with the hardwired CPC design, this design requires additional MUs.

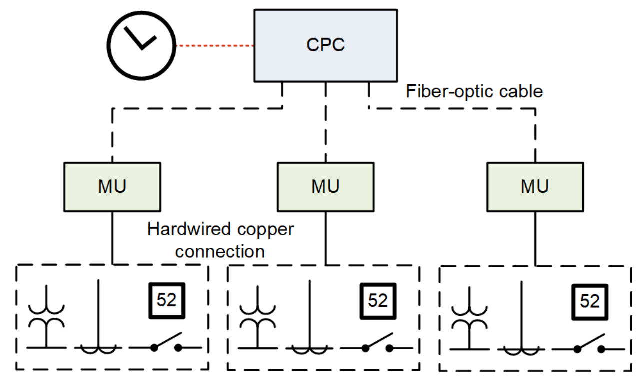

Fig. 4. P2P-based CPC system with direct fiber connection to MUs.

C. IEC 61850-Based CPC System

An IEC 61850-based CPC system utilizes the IEC 61850 standard to exchange process bus data between MUs and the CPC. Like the P2P design, the MUs located near the instrument transformers are hardwired and perform the initial data acquisition and digitization. These MUs are connected to the process bus. Data from MUs to the CPC are transferred via this network using Sampled Values (SV) and Generic Object-Oriented Substation Event (GOOSE) protocols. Fig. 5 shows a simplified network architecture for an IEC 61850-based CPC system. This design is suitable for both small and large substations, since a CPC can subscribe to many MUs. The number of MUs that the CPC can subscribe to is not limited by the number of communication ports available on the CPC. Hence, this design can more easily handle future substation expansion.

This design requires network switches and a dedicated time source for operation. All MUs and CPCs in this system are synchronized to an absolute external time. This synchronization is done via a network-based time distribution protocol, such as the Precision Time Protocol (PTP), connected to the relay via Ethernet or via a dedicated connection to a Global Positioning System clock, such as IRIG-B. Connecting to a high-accuracy external time source allows the MUs to time-stamp the collected data with high precision and allows the CPC to align the data streams received from different MUs and thus remove any effect of nonlinear network delays, sampling time variations, and other time-related errors that may cause a misoperation. Because protection functions depend on the Ethernet network and external time sources, robust network engineering is required. As standard protocols are used for data exchange, devices from various manufacturers can be used in this CPC design.

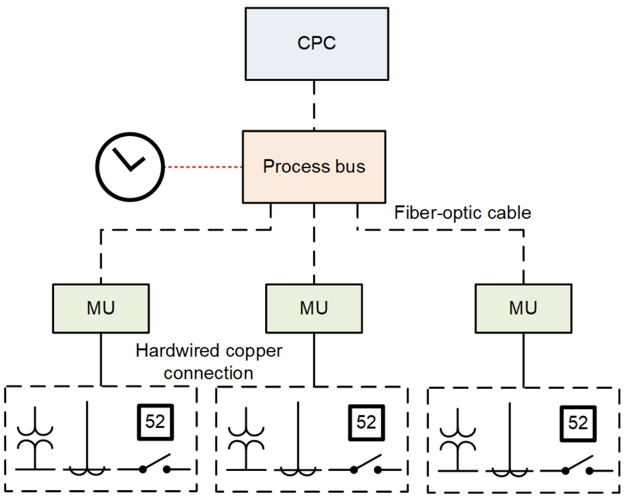

Fig. 5. IEC 61850-based CPC and MUs connected to process bus network.

IV. The Utility's Perspective on CPC

A. Potential Benefits

CPC systems offer several strategic advantages over the traditional designs for T/D substation protection. The most obvious of these benefits are a direct result of the reduced number of devices required. Fewer devices equate to fewer relay models to manage and install in the substation. This translates into the following benefits:

- A reduced number of devices to keep in inventory—The historical substation design utilized three different relay models for transformer and bus protection. The distribution circuit exit protection uses one of these models, and one relay is currently installed per circuit exit.
- A reduced number of devices to test and commission
- Reduced panel wiring (interrelay wiring)—A reduction in the amount of panel space will also be achieved.
- Reduced complexity in settings and software—There will be a reduction in the number of settings templates that are required.
- Reduced commissioning time—There will be a reduced number of settings templates applied and tested by the field. Theoretically, if a two-CPC approach is implemented, at most, there would be two core settings templates used.
- Simplified supervisory control and data acquisition (SCADA) communications

B. Technical Challenges

However, many of the aforementioned benefits might introduce new technical challenges that should be considered before proceeding. Many of these challenges are surmountable but will need to be engineered into the design. Some of these challenges might best be addressed with a human-machine interface (HMI), but this, in turn, will introduce new issues.

- Multiple settings groups—Traditional relay settings on circuit exit feeders utilize multiple settings groups, which are required for any new designs. A solution for this requires careful programming that does not introduce additional human error or unnecessary settings maintenance.
- Control logic with a redundant two-CPC approach—Careful consideration will need to be given on how to implement control functions within the primary and secondary CPCs. Some control functions (such as pure control, like reclosing, bank transfers, swapovers, and capacitor controls) can be implemented on the primary CPC and not the secondary CPC. With this approach, the secondary CPC will largely be used for redundant protection purposes only. Some functions, such as operating and tripping through SCADA, will also need to be implemented in only one of the CPCs, which will probably be the primary CPC. The approach of using one CPC for control does introduce some new challenges. For example, if the primary CPC were to fail, how would operators open and close the breakers if needed? Additional bypass control would need to be implemented.
- Operational complexity and operator interface—Historically, system operators performed many of their job functions on the front of the individual relays. A short list of these functions includes:
  - Blocking protective elements when performing substation switching. This might have included blocking reclosing or blocking ground protective elements while performing switching procedures.
  - Obtaining relay targets after an event.
  - Pressing a pushbutton to open or close a breaker. The current practice is using one pushbutton for open and using a different pushbutton for close on a single relay for each switching device (a breaker or a CS) in a T/D substation.

The movement toward centralized protection devices necessitates an HMI to perform many of the local operating functions. The HMI would be required to perform many of the control functions that were performed on the old-style control panels of yesteryear. The HMI introduces additional challenges. In an emergency, there is no button on the front of the relay to quickly open a breaker; HMIs require passwords and screen navigation skills. Currently, two different types of operators may come to the substation and interface with the protection. One is the typical substation operator, and the second may be a distribution line technician. While the distribution line technician can request a control center to block reclosing or apply a hot-line tag to a circuit, they will no longer have the front of a relay to check and verify that this functionality has occurred.

- Change management plan—The use of a P2P-based or an IEC 61850-based CPC system requires a significant change management plan and extensive lab testing prior to implementation.

Proper training of relay technicians and operators will help the utility navigate through many of these challenges. Any change should follow the historical approach of being deliberate and well thought out before implementation.

C. Design Questions

The utility has historically used a modularized approach to protection that has allowed for repeatability and low complexity with minimal custom configuration from one location to the next. With this approach, most changes in protection designs in T/D substations are only made after careful consideration of the impacts they will introduce.

A list of some of the important design questions that are typically considered are as follows:

- Backup versus redundancy.
- Standardization and repeatability—How repeatable is the design with minimal customization in both design and settings?
- Simplicity—Is the protection scheme easily understood by the engineers that design it, the technicians that install it, and the operators that use it?
- How does the ease of installation and testing compare between designs?
- How is the ease of troubleshooting and maintenance impacted? Any time protection functionality migrates from devices external to the relay to programming and logic within the relay, troubleshooting moves from wires and switches to troubleshooting logic.
- How much centralization is too much in one CPC system?
- How is cost versus benefits evaluated? It appears that many of the potential benefits from a more centralized design will be obtained over time; once the utility starts to follow this approach, cost savings would be obtained when the engineers become more proficient at using the system. The centralized approach is new and requires change management to achieve.

When weighing the potential benefits with the technical challenges of a CPC system, careful consideration needs to be given to how much and how fast any change should be implemented.

V. CPC System Design for the Utility's Distribution Substation

In this section, we discuss the existing P&C design used in the distribution substation under study. Using the existing P&C design as the reference, three separate CPC systems, i.e., hardwired, P2P-based, and IEC 61850-based, are designed for the entire substation. To avoid total loss of protection to the entire substation during a CPC failure, full redundancy of CPC devices is considered in the new design. Additionally, the existing P&C philosophy is maintained in the CPC designs. Next, we discuss the existing and new CPC designs for the substation under study in detail.

A. Existing P&C Design of Traditional Substation

Fig. 6 shows the single-line diagram, secondary connections, and P&C devices for the utility's existing distribution substation. The distribution substation consists of one delta-wye-grounded step-down transformer that is tapped from a 100 kV transmission line. The transformer (37 MVA) steps down the voltage to 24 kV and feeds two distribution feeders. CSs are installed at the high-voltage side of the transformer and circuit breakers (52) are installed at the low-voltage side for fault isolation.

The transformer protection consists of one transformer differential relay (87) and one backup overcurrent relay (51-HT). Protection elements used in each relay are shown in the figure. The transformer differential relay trips both the CS and the breaker. The backup overcurrent relay trips only the CS. The 24 kV distribution bus is protected by a bus overcurrent relay (51-LT). Each feeder is protected by a separate overcurrent relay (51-F31 and 51-F32). The bus relay trips the transformer low-side breaker, and feeder overcurrent relays trip their respective breakers. When the transformer low-side breaker is bypassed, the transformer differential protection uses the current signals from the auxiliary CT and includes a 24 kV bus in the differential zone. The existing substation uses one transformer relay and four overcurrent relays to protect the overall distribution substation.

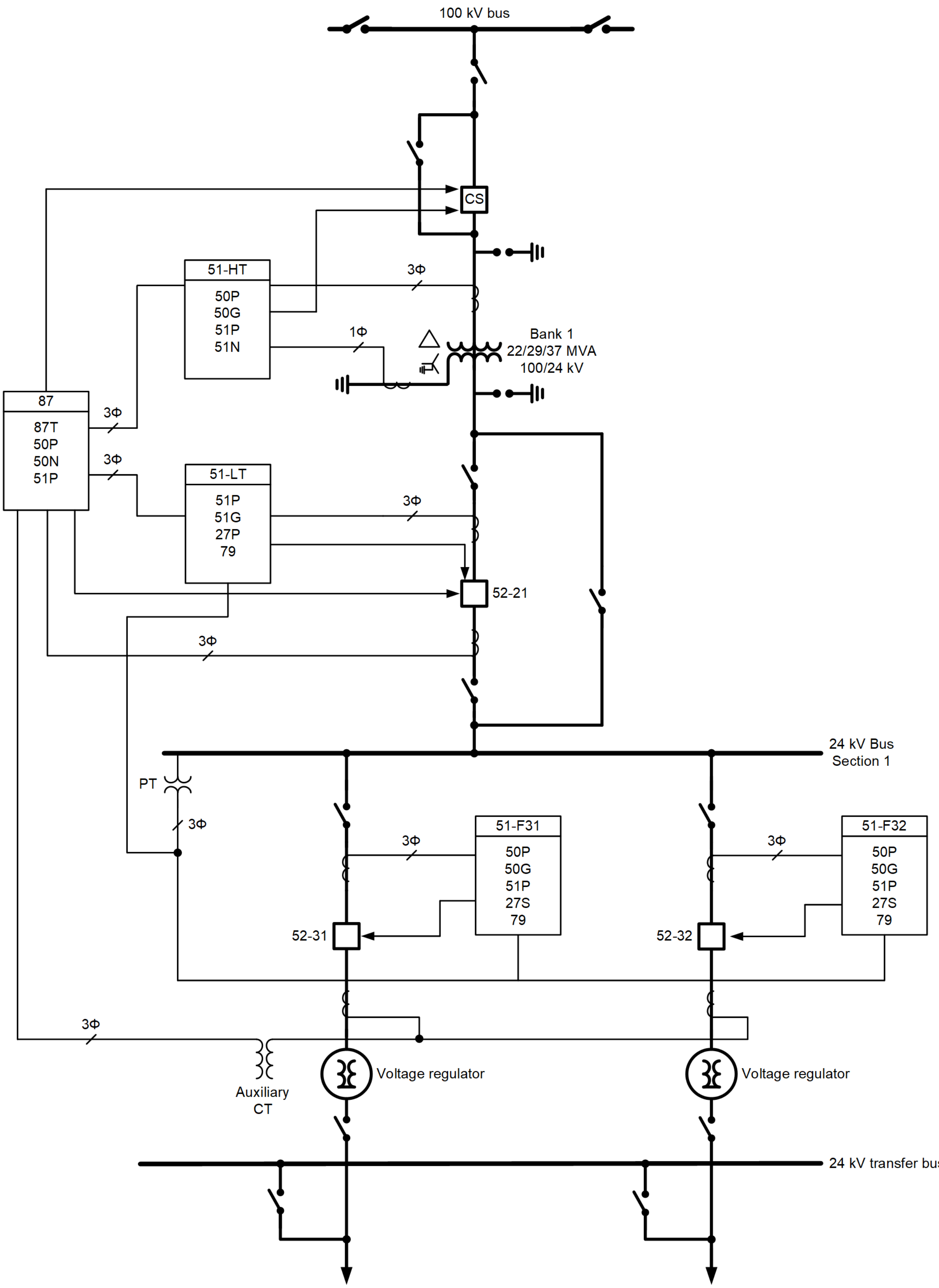

Fig. 6. Secondary connections of utility's existing distribution substation.

B. Hardwired CPC System Design

For the hardwired CPC system design, a powerful and flexible microprocessor-based relay capable of protecting a transformer and multiple feeders from a relay manufacturer was selected. Fig. 7 shows the secondary connection between primary equipment (circuit breakers [CBs], CTs, and PTs) and CPC systems. As discussed earlier, two CPC systems were installed for full redundancy. Each CPC system is capable of measuring signals from all CTs, PTs, and CBs and issuing trip and close signals to CBs and CSs. To avoid sensing redundant signals, only the current exiting transformer low-side circuit breaker is connected to the CPC system. All the protection elements that are enabled in the five relays in the existing distribution substation are aggregated in each CPC system. The hardwired CPC system design requires two powerful relays and some additional control cables for breaker control. The hardwired design is similar to the existing P&C design, and it does not include any additional hardware between the primary equipment and the CPC system.

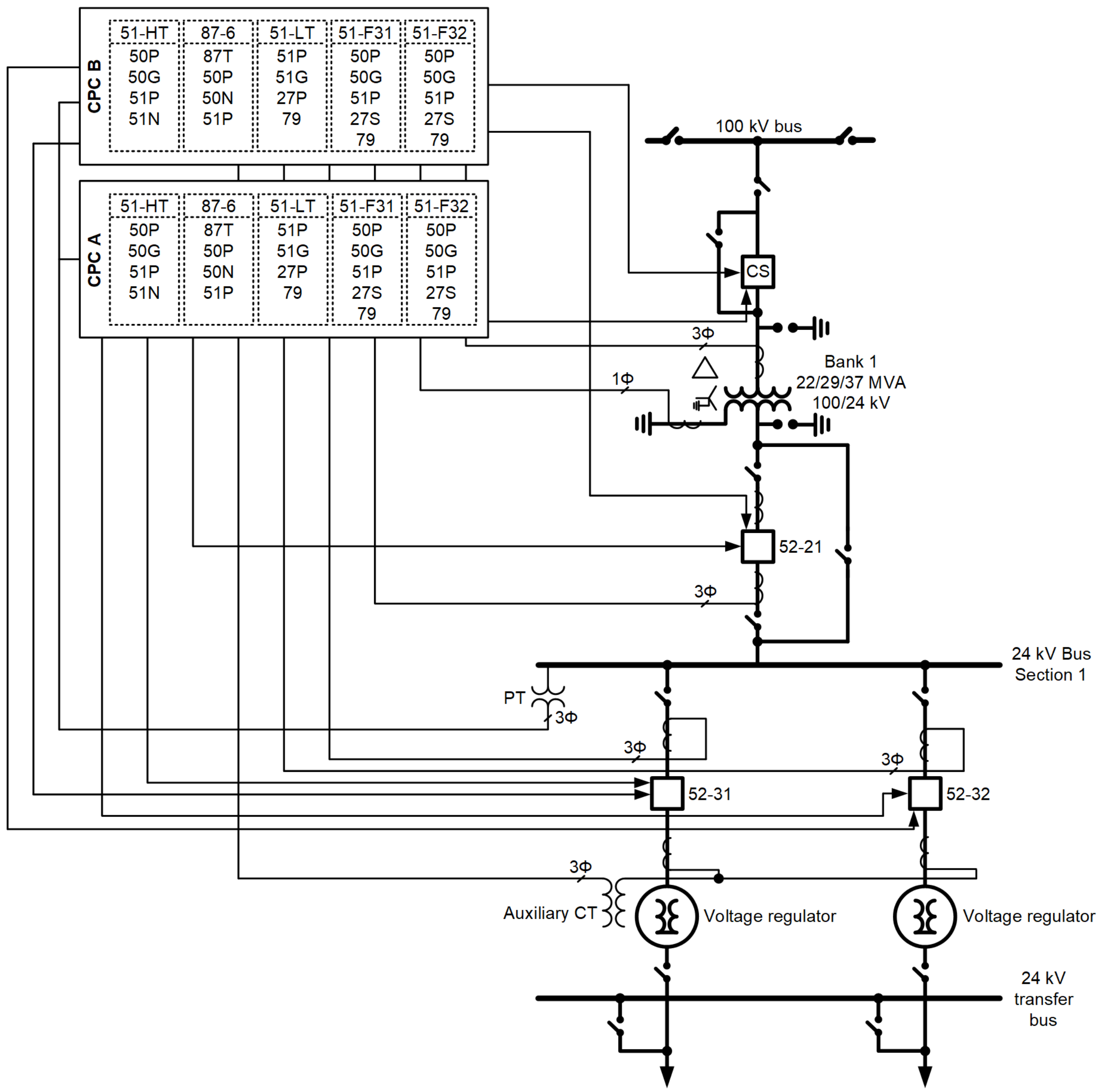

Fig. 7. Hardwired CPC system design for distribution substation under study.

C. *P2P-Based CPC System Design*

The P2P-based CPC system design for the distribution substation under study is shown in Fig. 8. For this design, a P2P MU and P2P CPC are used. Two P2P MU types are available: either eight CT inputs or four CT and four PT inputs. The P2P CPC has eight communication ports, allowing it to communicate with up to eight P2P MUs. The MUs use a manufacturer-specific, nonroutable protocol to exchange analog and binary signals with the CPC system at 10 kHz. The MUs do not have any user settings.

This CPC design requires six P2P MUs and two P2P CPC. The MUs are installed in the switchyard close to the primary equipment, and the CPCs are installed in the control house. A direct fiber-optic cable connects an MU with the CPC. The MU output contacts are used to trip the CS and CBs. If one MU fails, it impacts only one CPC system. The second CPC then trips the CS or CB through the healthy P2P MU. This design does not require any network switches or satellite clocks for running local protection functions.

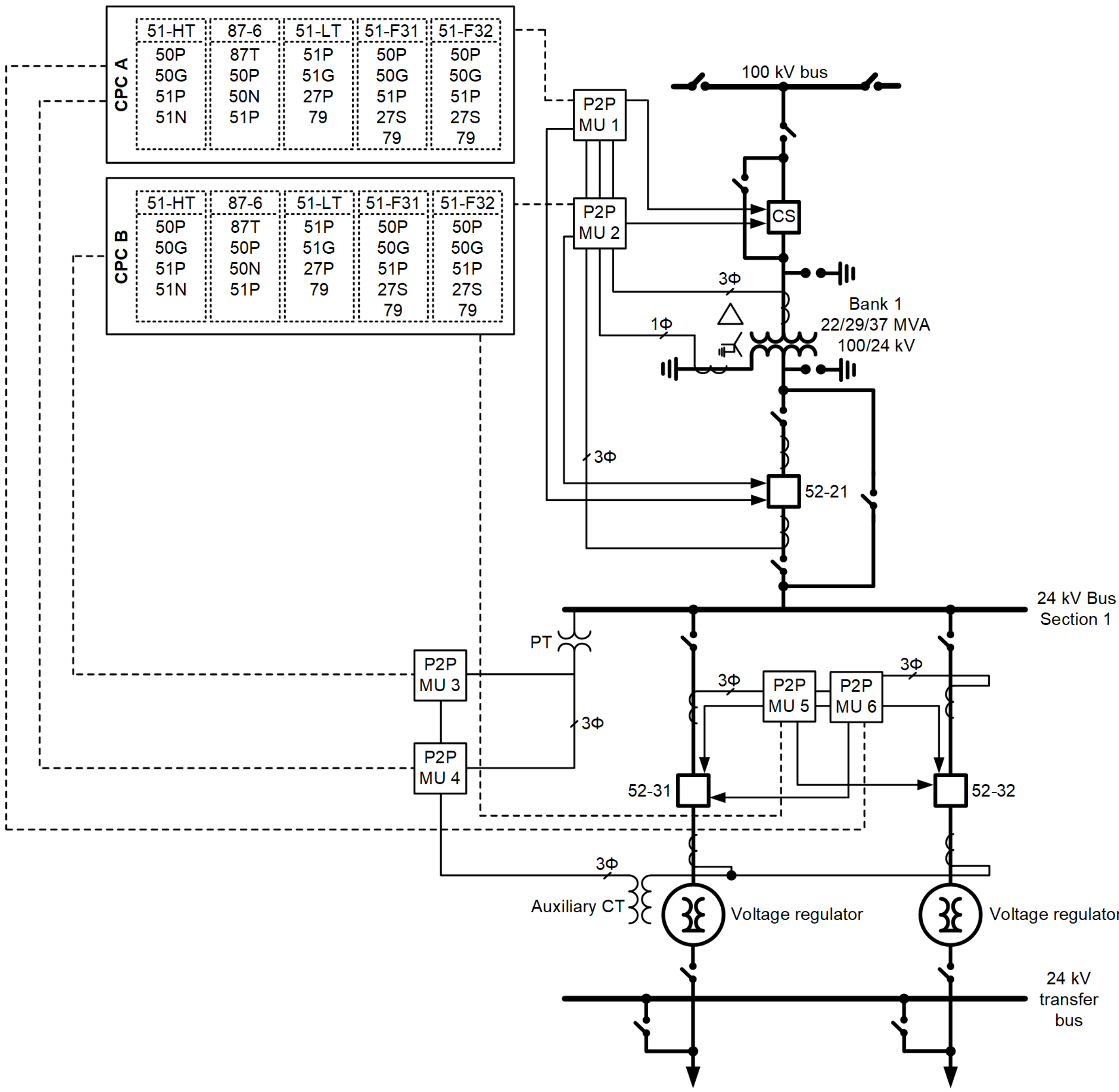

Fig. 8. P2P-based CPC design for distribution substation under study.

D. *IEC 61850-Based CPC System Design*

The final CPC system design is based on using process bus protocols, like SV and GOOSE, described in the IEC 61850 standard. The connections between CPCs, MUs, Ethernet switches, and satellite clocks for the IEC 61850-based CPC system design are shown in Fig. 9. The MU includes six CT and six PT inputs. The CPC supports a Gigabit Ethernet card capable of subscribing multiple SV streams.

The MUs were installed in the yard next to the primary equipment, and the CPC systems were installed in the control house. Two completely redundant CPC systems were designed using separate MUs, Ethernet switches, satellite clocks, and CPC. The failure of any equipment in System A does not impact System B. Although many network architectures can be used for each CPC system, such as failover or the Parallel Redundancy Protocol (PRP), a simple radial network architecture was selected because there are two independent CPC systems. Similar to the P2P-based CPC design, this design requires six MUs and two CPC. In addition, this design requires two PTP-aware Ethernet switches and two PTP-compliant satellite clocks. For this CPC system design, the protection functions depend on the availability of Ethernet switches and satellite clocks.

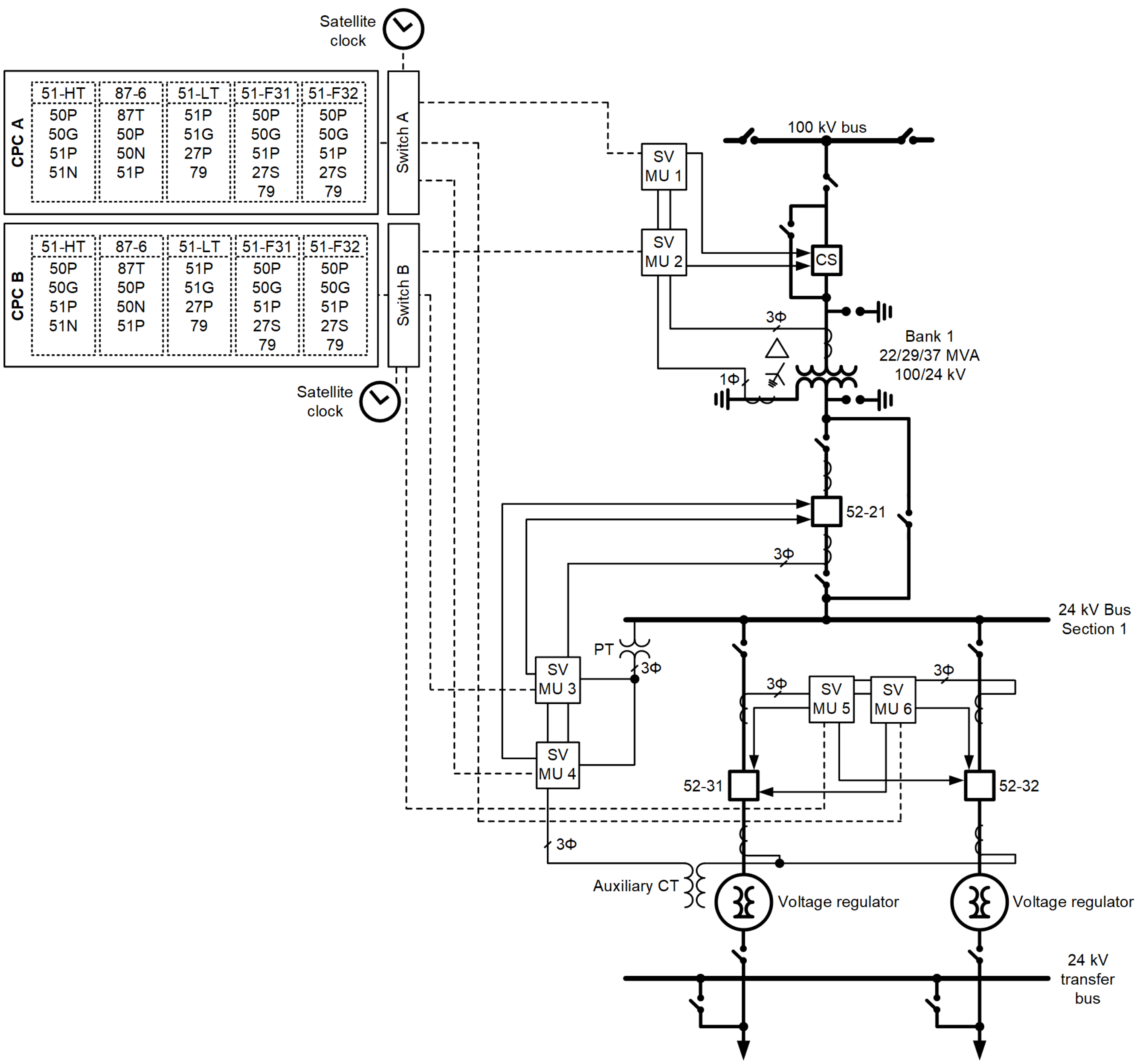

Fig. 9. IEC 61850-based CPC design for distribution substation under study.

VI. Comparison Between Existing P&C System and CPC System Designs

In the previous section, we presented the design of the existing P&C system and three CPC system designs for the substation under study. Next, we compare the CPC system designs analytically with the existing P&C system using device count, protection scheme unavailability, and operation speed of peer-to-peer communications-based protection schemes as criteria. The technical data presented in this section highlight the merits and challenges of each design. This information is helpful for utilities currently in the decision-making process for selecting a CPC system for a distribution substation of similar size.

A. Device Count

Table I lists various P&C devices used in all four designs. In the existing substation, one transformer relay and four overcurrent relays are used to protect the overall substation. In the traditional substation, copper cables connect CTs and PTs secondary to the relays. The hardwired CPC design uses the smallest number of devices out of all four designs, i.e., only two CPC. The CPC is connected to the CTs and PTs secondary via copper cables. Two CPC and six P2P MUs are used in the P2P-based CPC design. CTs and PTs secondary are connected to the P2P MUs, and the MUs are connected to the CPC using P2P fiber-optic cables. The IEC 61850-based CPC design requires the largest number of devices. Compared with the P2P-based CPC design, this CPC design requires two additional PTP-compliant Ethernet switches and two satellite clocks. In the IEC 61850-based CPC design, the MUs, CPC, and satellite clock are all connected to the Ethernet switch. Depending on the CPC design selected, the total number of devices can range from 2 to 12. When the number of devices increases, it has a direct impact on the cost, relay panel and control house size, substation dc battery system, testing and commissioning, and operation and maintenance of the substation.

Table I
Devices Used in Each Design

Device	Existing P&C Design	Hardwired CPC Design	P2P-Based CPC Design	IEC 61850-Based CPC Design
Relay	5	0	0	0
CPC	0	2	2	2
MU (P2P/ IEC 61850)	0	0	6	6
Ethernet switch	0	0	0	2
Satellite clock	0	0	0	2
Total Device Count	5	2	8	12

B. Protection Scheme Unavailability

Protection engineers use fault tree analysis as a tool to investigate the reliability of protection schemes. This technique quantifies the protection system reliability using probabilistic techniques. Usually, this method identifies an event of interest, a failure, and a tree of conditions or other events that can lead to this event, all expressed as a chain of logic gates. The value obtained from such an exercise is the unavailability of the system, which is the fraction of time when the identified failure occurs and the device cannot perform. Thus, when a system has a high unavailability value, its dependability is lowered. Each basic event has an unavailability value that can be calculated using (1). It is unitless.

$$q \cong \lambda T = \frac{T}{\text{MTBF}} \tag{1}$$

where:

q is the unavailability value.

λ is some constant failure rate.

T is the average downtime per failure.

MTBF is the mean time between failures (λ^{-1}).

The unavailability analysis of protection schemes for all four designs is carried out using the fault tree analysis technique described in [4]. Table II lists the MTBF values and the unavailability values for each component used in the fault tree analysis. It should be noted that the MTBF value for a traditional relay is higher than that for an MU or a CPC. This stems from the long and continued use of traditional relays, which have been installed in large numbers and have been in operation for decades, compared to MUs or CPCs, which are relatively new devices with limited current usage. As more MUs and CPCs are installed, more data are available to make a better judgment regarding their MTBF values, which are expected to rise. To calculate the unavailability from MTBF, an average downtime per failure (T) of 2 days is assumed. The calculation also assumes that human failures take 1 year to detect and correct and hardware failures are 100 times more likely. The unavailability for misapplication due to human error is calculated by multiplying the hardware MTBF by 100 and taking the inverse. Please note that MTBF values are subjective. These values can vary between different manufacturers, and they improve over the years with high-quality parts and improved design. However, the fault tree will remain the same.

TABLE II
UNAVAILABILITY FOR EACH COMPONENT

Component	MTBF (Years)	Unavailability (10^{-6})
Traditional relay	1,200	4.57
MU	600	9.13
CPC	600	9.13
Ethernet switch	300	18.26
Satellite clock	1,000	5.48
Product misapplication	NA	$(\text{MTBF} \cdot 100)^{-1} \cdot 1$ year
Global Navigation Satellite System antenna	1,000	9.13
Fiber-optic cable	5,000	1.10
Copper wiring	10,000	0.54
Circuit breaker	NA	300
CS	NA	300
DC power system	NA	50
Current transformer (per phase)	NA	10

The first top event that was calculated for all four designs was the transformer protection failing to clear the fault in the prescribed time. The fault tree for the traditional substation is shown in Fig. 10. This fault tree is constructed using the existing P&C design shown in Fig. 6. This failure occurs if the breaker, CS, dc power system, wiring, CTs, or the transformer relay fail. As discussed earlier, all three CPC designs include redundant CPC to avoid loss of total substation protection during a CPC failure. Fig. 11 shows the fault tree for the same top event for the hardwired CPC design. This fault tree is developed using the hardwired CPC design from Fig. 7. Adding a redundant hardwired CPC decreases the overall unavailability from 723.44e^{-6} to 710.54e^{-6}.

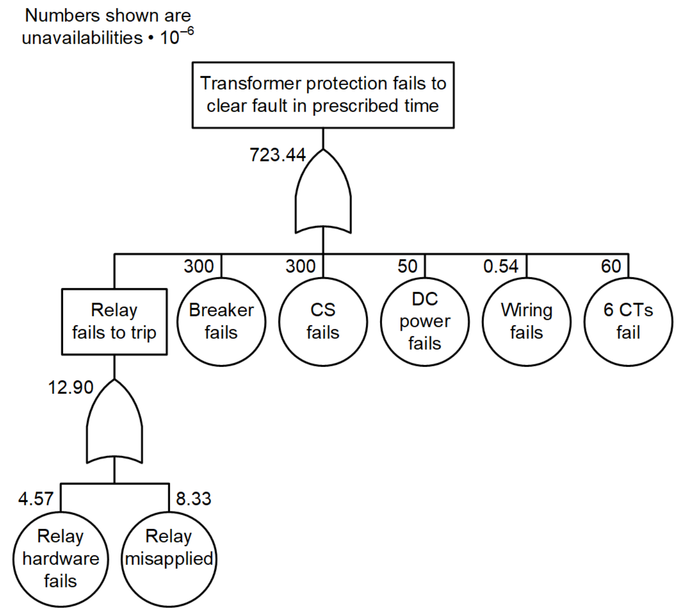

Fig. 10. Fault tree for transformer protection in existing substation.

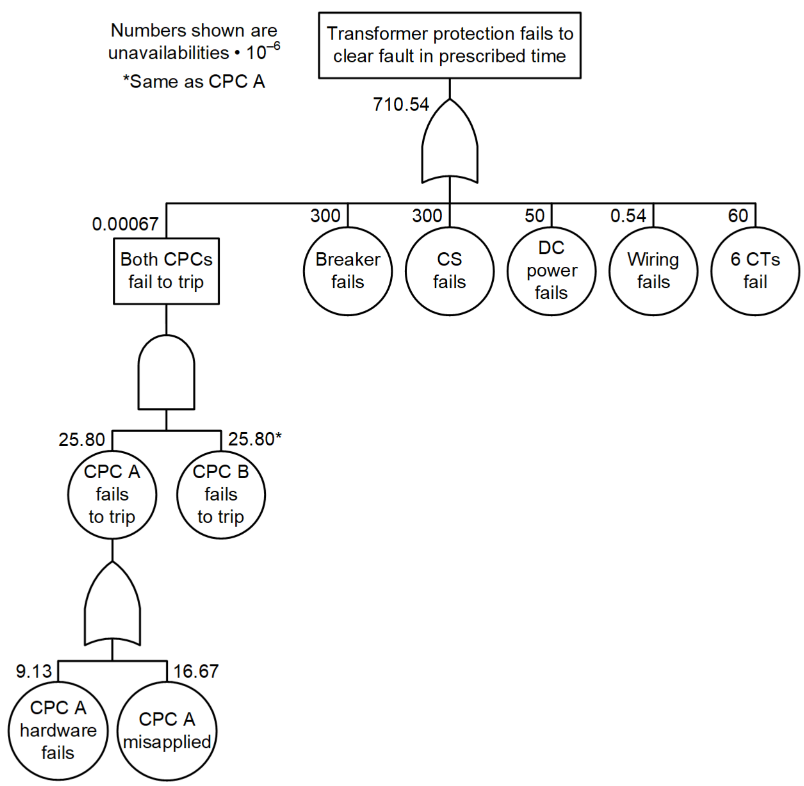

Fig. 11. Fault tree for transformer protection in hardwired CPC design.

Using the P2P-based CPC design shown in Fig. 8, the fault tree for the same top event is calculated and shown in Fig. 12. The fault tree for this design includes additional failures for the P2P MU and fiber-optic cable connection between the MU and the CPC. Since the P2P MU does not have any user settings, a P2P MU misapplication is not included in the fault tree. Fig. 13 shows the fault tree for the IEC 61850-based CPC design. This fault tree is constructed using the CPC design from Fig. 9. This fault tree has the highest number of failures as additional devices like Ethernet switches and satellite clocks are essential for protection. Although the unavailability of a CPC A system failure is high, i.e., 156.96e^{-6}, installation of a redundant CPC B system lowers the unavailability to 0.025e^{-6} for both CPC system failures.

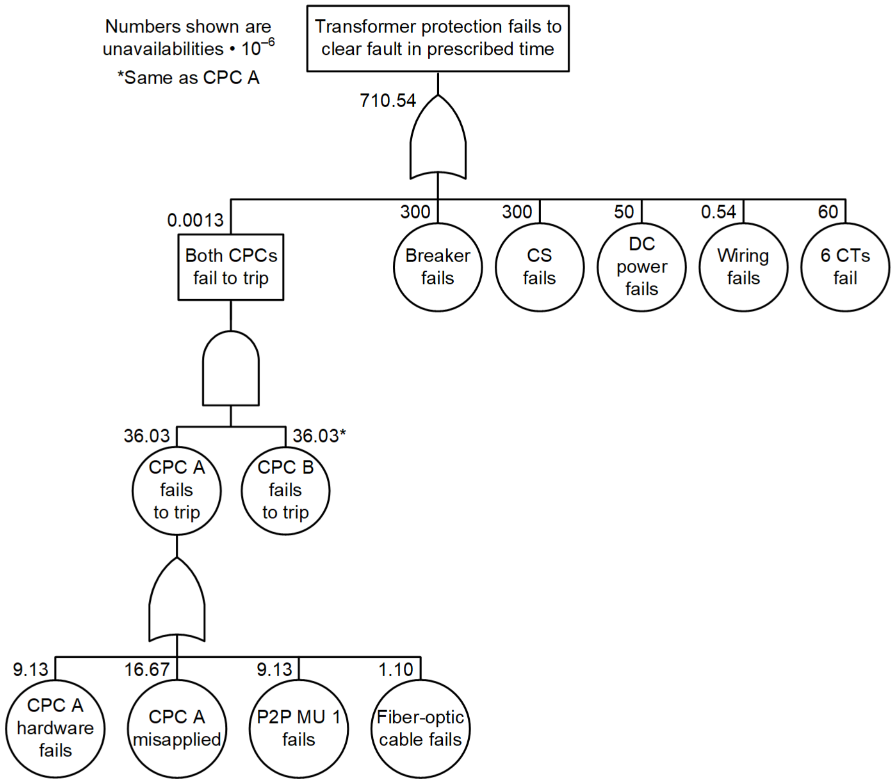

Fig. 12. Fault tree for transformer protection in P2P-based CPC design.

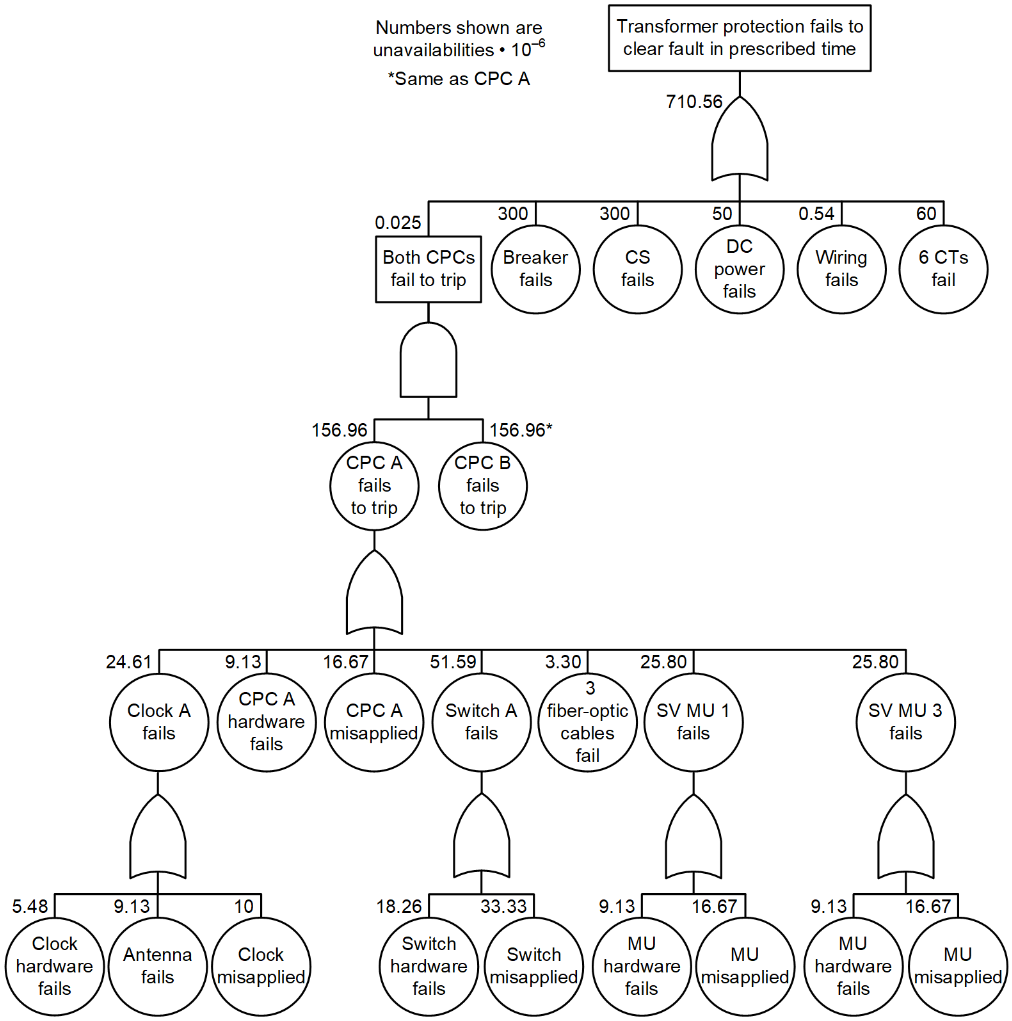

Fig. 13. Fault tree for transformer protection in IEC 61850-based CPC design.

Table III shows the unavailabilities for the traditional transformer protective relay and three CPC variants. Since the MTBF of the traditional relay is twice that of the hardwired CPC, its unavailability is half compared to the hardwired CPC, when redundancy is not considered. As the P2P-based CPC requires an MU and a fiber-optic cable for data acquisition, its unavailability is higher than that of the hardwired CPC. The IEC 61850-based CPC has the highest unavailability, when redundancy is not considered, as it requires MUs, a clock, an Ethernet switch, and fiber-optic cables. The second column of Table III indicates that as more hardware is added to perform the same P&C function, the unavailability increases. The unavailabilities for three CPCs with full redundancy are listed in the third column of Table III. If redundancy is not considered for a CPC system, its unavailability will be higher than that of the traditional relay.

TABLE III
RELAY AND CPC UNAVAILABILITY (10^{-6})

Solution	Without Redundancy	With Redundancy
Traditional relay	12.90	NA
Hardwired CPC	25.80	0.00067
P2P-based CPC	36.03	0.0013
IEC 61850-based CPC	156.96	0.0250

The second top event that was calculated for all four designs was the feeder protection failing to clear the fault in the prescribed time. The fault trees for the second top event are not shown in this paper. The overall unavailabilities for both top events are shown in Table IV. For the traditional substation, the overall unavailability is slightly higher, as redundant relays are not installed for transformer and feeder protection. For the three CPC systems, the overall unavailabilities are comparable. Although the number of devices used in the IEC 61850-based CPC design is the highest, installation of a full redundant protection design lowers the overall unavailability. A reduction in the unavailability can be obtained by increasing the quality and lowering the MTBF values of individual components in the system, by simplifying the system to lower the number of components, or by adding redundancy to the system to improve reliability at the cost of complexity [5].

TABLE IV
OVERALL UNAVAILABILITY (10^{-6})

Solution	Transformer Protection	Feeder Protection
Traditional substation	723.44	393.44
Hardwired CPC system	710.54	380.54
P2P-based CPC system	710.54	380.54
IEC 61850-based CPC system	710.56	380.56

C. Protection System Operation Speed for Peer-to-Peer Communications Schemes

Many power system protection applications are deployed in substations using peer-to-peer communications between protective relays [6]. Breaker failure and fast bus trip are two widely used protection schemes that rely on peer-to-peer communications. When relays share information with each other, fast P&C is possible, resulting in improvements to power system reliability. Relays can communicate with other relays using contact inputs and outputs, dedicated peer-to-peer communications channels, and a local-area network. When protection schemes use peer-to-peer communications, the protection speed depends on the inherent latency of the communications medium used.

In this subsection, we discuss breaker failure and fast bus schemes and present test results that demonstrate the improvement in protection speed when these schemes are implemented in CPC systems. In a CPC system, all substation protection functions are implemented in a single piece of hardware, which eliminates the need for peer-to-peer communications for protection. Thus, protection action can be taken much faster and without the additional complication of transmitting and receiving data between relays. Fast protection results in a faster fault-clearing time. When faults are cleared quickly, it enhances personnel safety, limits equipment damage, and improves the power quality.

Fig. 14 shows the test setup used to measure the communication latency for three peer-to-peer communications media. The two relays selected for the test match the overcurrent relays used in the utility's distribution substation. Both relays execute protection algorithms four times per power system cycle. First, one contact output of Relay 1 is connected to the contact input of Relay 2. The contact input debounce time is set to the default value of 0.5 cycles. Second, Mirrored Bits communications is set up between the two relays. The Mirrored Bits protocol communicates at a baud rate of 19200 with an input debounce of 1 message on the channel. Finally, IEC 61850 GOOSE communications is set up between the two relays over a simple switched network. The contact input debounce time and Mirrored Bits speed settings correspond to settings used in the utility's distribution substations.

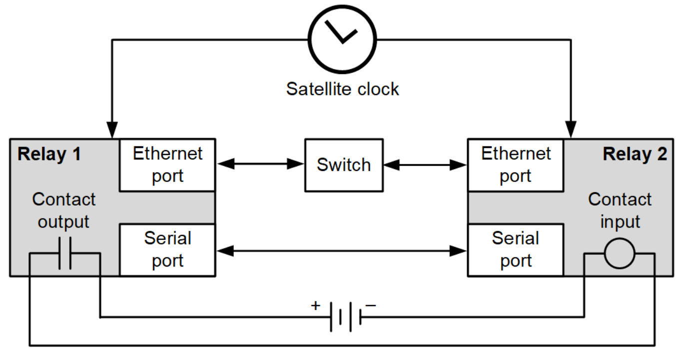

Fig. 14. Setup for peer-to-peer communications speed test.

An event is triggered in Relay 1, and the data are sent over to and read by Relay 2 using the three methods. The time difference between triggering the event in Relay 1 and receiving the information in Relay 2 is recorded and analyzed. The test step is repeated multiple times, and the maximum latency for each communications medium is tabulated in Table V. From the table, it is clear that the fastest communications method is GOOSE, which takes 6 ms to operate, followed by Mirrored Bits communications, which takes 10 ms to operate. The slowest is the hardwired contact input/output (I/O) medium, which takes 18 ms to operate. The main component of this delay is the input debounce time, which has been left at the default value of 0.5 cycles. It should be noted that, depending on the application, the user can modify the settings to improve communications speed [7].

TABLE V
RELAY-TO-RELAY COMMUNICATIONS SPEED TEST

Solution	Maximum Time (ms)
Contact I/O	18
Mirrored Bits communications	10
GOOSE	6

Fig. 15 shows the test setup used to compare the protection speed of peer-to-peer communications-based protection schemes in existing and CPC designs. The substation power system model is simulated in a real-time digital simulator. The connection of currents, voltages, contact outputs, and communication links are shown in the figure. The feeder relay is configured to send signals to the bus relay via contact I/O, Mirrored Bits communications, and GOOSE protocol. The difference between the CPC and a traditional design is the location of the two protection zones (bus zone and feeder zone). In the CPC, they are co-located in a single device, but they are in different devices in the traditional substation.

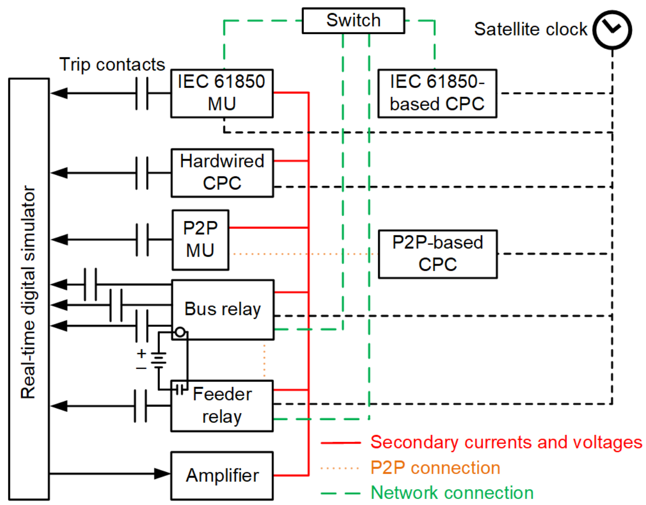

Fig. 15. Test setup for comparing peer-to-peer communications-based protection schemes.

1) Breaker Failure Scheme

Breaker failure protection is a backup protection scheme used to take remedial action in case a circuit breaker fails to open. Traditionally, in a zone protection scheme, if a relay detects that a fault has occurred in its zone, it issues trip signals to the corresponding breakers in the zone, which open to interrupt the fault. However, if the circuit breaker fails to open, then the relay sends a breaker failure trip command to relays in surrounding zones of protection. These secondary relays then issue trip commands to their in-zone breakers, which open to isolate the fault [8].

To test the breaker failure scheme, the trip duration setting is set to 9 cycles and the breaker failure initiate timer setting is set to 12 cycles in the feeder relay. If the feeder breaker does not open after 12 cycles from the trip signal, it sends a breaker failure signal to the bus relay via the three communications media discussed earlier. When the bus relay receives the breaker failure signal, it issues a trip signal to the simulator. The bus relay has three trip contacts, one for each communications medium. CPC systems are configured to issue a breaker failure trip signal to the simulator 12 cycles after the initial trip signal has asserted. The overcurrent elements in the feeder relay and all three CPC are set to the same value. A fault is simulated on the feeder, and the feeder breaker is blocked from tripping to mimic a breaker failure condition. After the breaker failure initiate timer expires, the feeder relay sends breaker failure signals to the bus relay. When the bus relay receives the breaker failure signal, it trips an output contact, one for each breaker failure signal received from each peer-to-peer communications medium. Each CPC system also issues a breaker failure trip signal to the simulator. In P2P-based and IEC 61850-based CPC systems, an MU digitizes CT and PT signals and publishes them to the CPC. Similarly, the CPC sends a trip signal to the MU. Since the MU acts as an interface between the primary equipment and the CPC, there is a finite delay for fault detection and another delay for the trip signal transfer. Consequently, protection system operation speed is adversely impacted if these delays are significant.

The time difference between the fault initiation and the breaker failure trip signals received from the bus relay and the three CPC systems is measured in the simulator. This time represents the overall breaker failure scheme operation time. The test was repeated 100 times, and the test results are shown in Fig. 16. Each blue dot is a test point, with the black dot being the average operation time. The variations in the operating times are primarily due to the data acquisition and processing pipeline of the relays.

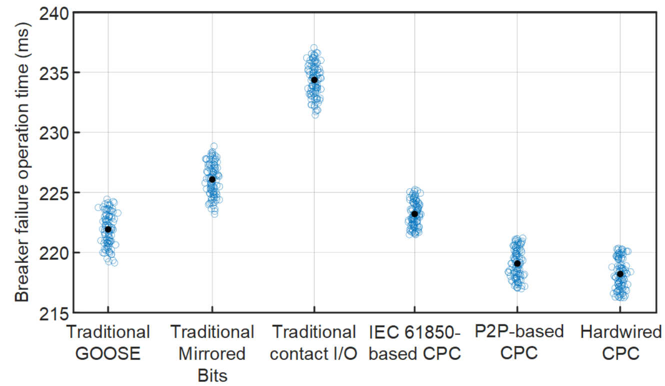

Fig. 16. Breaker failure operation times for different systems.

Table VI lists the average breaker failure scheme operation time for each system. The hardwired CPC system is the quickest to trip the breaker connected to the bus zone, operating in around 218 ms. This is followed by the P2P-based CPC with MUs connected via a dedicated link, which provides both the fastest and the deterministic path for analog and data transfer. The P2P-based CPC system is slightly less than 1 ms slower than the hardwired CPC system. The IEC 61850-based CPC system is around 1.3 ms slower than the traditional system using GOOSE for peer-to-peer communications. It is because, in an IEC 61850-based CPC system, there is a 1.5 ms channel delay associated with receiving SV streams from the MU. Finally, the traditional design that uses contact I/O is the slowest. It is important to remember that depending on the settings used (contact input debounce time, Mirrored Bits communications speed) and the amount of network traffic on the IEC 61850-based system, the operation time can vary.

TABLE VI
AVERAGE BREAKER FAILURE SCHEME OPERATION TIME (MS)

System	Operation Time (ms)	Difference (ms)
Hardwired CPC	218.252	NA
P2P-based CPC	219.091	0.8725
Traditional GOOSE	221.936	3.7170
IEC 61850-based CPC	223.225	5.0035
Traditional Mirrored Bits communications	226.088	7.8690
Traditional contact I/O	234.375	16.156

2) *Fast Bus Trip Scheme*

A fast bus trip scheme is used to isolate a fault on a bus much more quickly than traditional bus overcurrent protection. Although differential protection is the best scheme for bus protection, it is not always used due to the additional requirements with regard to equipment, design, and maintenance. An alternative and simple design is to use time-delayed overcurrent protection on the bus, which operates after the overcurrent protection on the feeder. In this case, for a feeder fault, the feeder overcurrent operates first and isolates the fault. For a bus fault, none of the feeder relays operate and the fault remains until the bus overcurrent operates [9] [10]. This scheme is inherently slow due to the waiting period to clear a bus fault. To increase the speed of fault isolation, both the feeder relay and the bus relay have fast overcurrent protection enabled. When a feeder fault occurs, the feeder relays send a block signal to the bus relay to prevent its fast overcurrent from picking up and tripping the breaker. For a bus fault, the feeder relays do not block the bus relay fast overcurrent protection, thus clearing the fault faster. To avoid a race condition, the bus and feeder overcurrent elements are separated by a short time delay. This scheme involves the communication of block signals from feeder relays to the bus relay [9].

Using the test setup shown in Fig. 15, the fast bus scheme in the traditional design and the three CPC designs are tested. The feeder relay sends block signals to the bus relay for the feeder fault using the three communications media. For this test, the bus relay is configured with a definite-time delay setting of 2 cycles to account for the blocking signal from the feeder relay to be transmitted, received, and processed [10]. Table V lists the maximum latency for the three relay-to-relay communications media. Based on the communications medium used, the definite-time delay setting of 2 cycles can be lowered. In CPC systems, overcurrent elements for both feeder and bus protection are executed in a single device. Hence, for the three CPC systems, the definite-time delay settings are set to zero. The bus fault is simulated in the simulator, and trip signals from the bus relay and the three CPC systems are monitored. The fast bus scheme operation time, which is the time difference between the fault initiation and the reception of the trip signal in the simulator, is measured. The test is repeated 100 times.

The operation times for the four systems are plotted in Fig. 17, and the average time is tabulated in Table VII. From the data, it is clear that the CPC systems outperform the traditional system by a large margin. While the traditional multi-intelligent electronic device system takes around 52 ms to clear the bus fault, the CPC systems take anywhere between 18 ms and 23 ms to clear the same fault. Out of the three, the hardwired CPC system is the fastest, taking 18 ms to clear. The CPC with MUs connected via a peer-to-peer dedicated communications channel is slightly slower at 19 ms, while the CPC with MUs connected via SV over a switched network takes 23 ms. The P2P-based CPC system uses direct fiber-optic communications to exchange signals at 10 kHz, resulting in a faster operation time than the IEC 61850-based CPC system. For the latter CPC system, there is a channel delay of 1.5 ms for SV and an additional delay for transmitting a trip signal to the MU via GOOSE communications. For the traditional system, the definite-time delay setting of 2 cycles is the main component for the overall operation time. Compared with the breaker failure operation time, the gain in fast bus scheme operation times for CPC systems is significant.

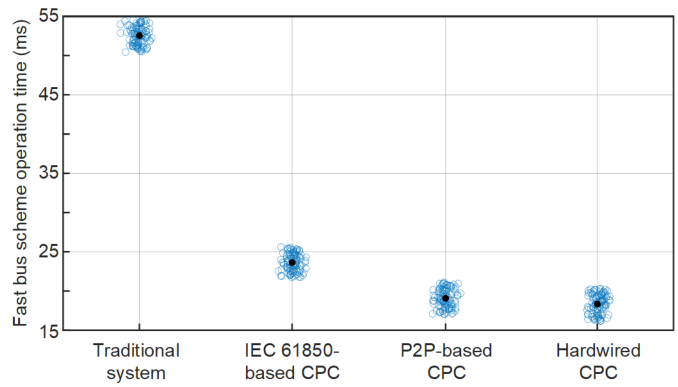

Fig. 17. Fast bus scheme operation times for different solutions.

TABLE VII
AVERAGE FAST BUS SCHEME OPERATION TIME (MS)

Solution	Operation Time (ms)	Difference (ms)
Hardwired CPC	18.339	N/A
P2P-based CPC	19.072	0.734
IEC 61850-based CPC	23.627	5.288
Traditional system	52.555	34.217

D. *Overall Comparison*

Each of the three CPC system designs, considered for the distribution substation at the utility, has certain benefits and challenges when compared to the existing P&C system. Table VIII provides an overall comparison of all four designs for a few critical attributes in a distribution substation.

TABLE VIII
COMPARISON BETWEEN EXISTING P&C SYSTEM AND CPC SYSTEMS

	Existing P&C System	**Hardwired CPC System**	**P2P-Based CPC System**	**IEC 61850-Based CPC System**
Number of Devices	5 relays (1 transformer relay and 4 overcurrent relays)	2 CPC	2 CPC and 6 MUs	2 CPC, 6 MUs, 2 Ethernet switches, and 2 satellite clocks
Panel Space	There is enough panel space to house 5 relays.	The hardwired CPC will be larger. The panel space will be similar to the existing design.	The P2P-based CPC is smaller and will require less panel space. MUs will require outdoor cabinets in the switchyard.	The CPC for this design is smaller and requires less panel space. MUs require outdoor cabinets in the switchyard. Additional panel space is needed for Ethernet switches and clocks.
Testing and Commissioning	Each relay needs its own testing and commissioning procedure.	Fewer devices result in a reduction in testing and commissioning. Existing processes can be followed.	Test MUs are needed for testing and commissioning. Existing test plans can be reused.	A test set that can inject SV and GOOSE is needed. The tester needs to be familiar with the testing method described in the IEC 61850 standard.
Settings Files	Each relay has its own settings files.	The number of settings files is low.	The settings files are the same as those of the hardwired design.	Settings files are needed for CPC, switches, and clocks. Separate IEC 61850 configuration files are needed for CPCs and MUs.
Unavailability	High	Low with redundancy	Low with redundancy	Low with redundancy
Peer-To-Peer Communications-Based Protection Scheme Speed	Slowest	Fastest	Slightly slower than hardwired system	Slower than P2P-based system but faster than existing system
Suitability	Substations of all sizes	Small distribution substations and retrofit applications	Small- to medium-size substations	Substations of all sizes
Future Expansion	New relays can be installed to handle future needs.	Future expansion is limited to the number of analog and binary inputs and outputs available in the CPC.	Future expansion is limited to the total number of communication ports available on the CPC.	The system can easily accommodate future expansion needs.
High-Accuracy Time Source Requirement	No	No	No	Yes
Network Engineering Requirement	No	No	No	Yes
Communications Protocols for Protection	Communications protocols are only needed for peer-to-peer communications-based protection schemes.	No.	Communication between CPC and MUs is handled by the manufacturer.	Configuration of SV and GOOSE is required.
Training Requirement	No training is required.	Training is the same as existing design.	Training is needed on how to test and commission MUs.	Extensive training is needed.
Substation-Wide Disturbance Recording	A dedicated disturbance fault recorder is required.	The CPC can capture substation-wide signals in event records.	Disturbance recording is the same as that of the hardwired CPC.	Disturbance recording is the same as that of the hardwired CPC.
Front Panel Targets	Each relay has its own front panel targets, which help operators quickly identify the nature of faults.	A separate HMI is needed to replicate the behavior of existing front panels for each protection zone.	The front panel targets are the same as those of the hardwired CPC.	The front panel targets are the same as those of the hardwired CPC.

VII. Lessons Learned and Future Plans

Although this case study was carried out for a small distribution substation, many lessons were learned. A CPC system aggregates all protection, control, and monitoring functions, which are distributed in multiple relays in an existing substation, in one piece of powerful hardware. Unfortunately, a CPC failure will result in total loss of protection. Hence, any CPC system design will require at least two redundant CPC. Distribution substations typically do not include redundant protective relays. When a CPC system is designed for a distribution system, installation of redundant CPC increases the overall reliability of the protection system. Depending on the CPC design selected, the number of devices can decrease (for a hardwired CPC system) or increase (for an IEC 61850-based CPC system). There were some protection speed benefits observed for communications-based protection schemes (e.g., breaker failure and fast bus trip) when using a CPC system design. Aggregating all substation functions in a few CPC brings certain challenges for operation and maintenance. The operation and maintenance staff will require new processes and training for the CPC systems. Overall, we believe that further centralization of protection may offer benefits that warrant further exploration.

Potential real-world applications of CPC systems at the utility are being considered. The utility's initial applications would use a hardwired CPC approach to limit the change management issues associated with MUs. The initial selected substations would likely be single bank to reduce the complexity associated with the configuration required for a multiple-bank substation. This initial step would help build confidence within the engineering and field organizations with the CPC approach. Using a phased approach to implementing new technologies helps build confidence and may help reduce human performance error associated with changing too many established processes at once. Plans would eventually be expanded to include multiple banks and digital substation technologies, although this is dependent on the success of initial designs and implementation.

VIII. Conclusion

In this paper, we present three CPC system designs for a distribution substation at the utility. The CPC system designs are compared against the existing P&C system using total device count, protection scheme unavailability, and protection system operation speed as criteria. During the case study, it was observed that the total device count can range from 2 devices for a hardwired CPC system to 12 devices for an IEC 61850-based CPC system. Regarding protection scheme unavailability, the unavailability of all three designs is found to be very close. Finally, a significant gain in protection speed was observed for breaker failure and fast bus trip schemes in all three CPC system designs when compared to the existing system. This paper also includes comparative analysis of three CPC system designs regarding various areas related to substation design, operation, and maintenance.

The utility is planning to use the technical data from this collaborative case study to evaluate available CPC systems for their distribution substation. This study will allow the utility to better understand the benefits and challenges of each CPC design. The utility will support a follow-up case study project to look at a CPC design for a multiple-bank distribution substation with additional control system requirements.

IX. References

[1] R. Hunt, "Process Bus: A Practical Approach," *PAC World Magazine,* spring 2009, pp. 54–59.

[2] Schweitzer Engineering Laboratories, Inc., "Digital Secondary Systems." Available: selinc.com/products/distribution/protection/digital-secondary-systems/.

[3] IEEE Power System Relaying Committee Working Group K15, "Centralized Substation Protection and Control," December 2015. Available: pes-psrc.org/kb/report/020.pdf.

[4] E. O. Schweitzer, III, B. Fleming, T. J. Lee, and P. M. Anderson, "Reliability Analysis of Transmission Protection Using Fault Tree Methods," proceedings of the 24th Annual Western Protective Relay Conference, Spokane, WA, October 1997.

[5] E. O. Schweitzer, III, and D. E. Whitehead, "Resetting Protection System Complexity," proceedings of the 46th Annual Western Protective Relay Conference, Spokane, WA, October 2019.

[6] M. Yalla, M. Adamiak, A. Apostolov, J. Beatty, S. Borlase, J. Bright, J. Burger, S. Dickson, G. Gresco, W. Hartman, J. Hohn, D. Holstein, A. Kazemi, G. Michael, C. Sufana, J. Tengdin, M. Thompson, and E. Udren, "Application of Peer-to-Peer Communication for Protective Relaying," *IEEE Transactions on Power Delivery*, Vol. 17, No. 2, April 2002, pp. 446–451.

[7] D. J. Dolezilek and A. Kalra, "Comparison of Standardized Protocols Available to Replace Substation Copper Field Wiring With Digital Communications," proceedings of the 14th International Conference on Developments in Power System Protection, Belfast, United Kingdom, March 2018.

[8] B. Kasztenny and M. J. Thompson, "Breaker Failure Protection — Standalone or Integrated With Zone Protection Relays?" proceedings of the 37th Annual Western Protective Relay Conference, Spokane, WA, October 2010.

[9] E. McCollum, K. Hao, S. V. Achanta, J. Blair, and D. Keckalo, "Low-Cost Fast Bus Tripping Scheme Using High-Speed Wireless Protection Sensors," proceedings of the 45th Annual Western Protective Relay Conference, Spokane, WA, October 2018.

[10] D. Fentie, J. P. Reilly, and O. Reynisson, "Fast Bus Tripping With IEC 61850," SEL Application Guide (AG2017-32), 2017. Available: selinc.com.

X. Biographies

Stephen B. Ladd received his BSEE from Grove City College in 1986, MSEE from Georgia Tech in 1987, and MBA from Queens University of Charlotte in 2003. He has been a member of IEEE for 37 years and a member of IEEE Power & Energy Society since 1987. He is a registered professional engineer in the state of North Carolina and has worked at Duke Power, Duke Engineering & Services, and Duke Energy Corporation since 1987. Stephen has held engineering positions in substation apparatus, protection and control, and asset management. He is currently a principal engineer in the transmission system standards group.

Taylor I. Raffield received his BSEE from Clemson University in 2010 and MEE in 2014 from the University of Idaho. He is a member of the IEEE and IEEE Power & Energy Society. He is a licensed professional engineer in the state of North Carolina. Presently a lead engineer in the transmission system standards group, he has held positions in the protection and control engineering departments in two of the regions of Duke Energy. His responsibilities include developing enterprise-wide protection and control engineering standards.

Ethan Haithcox received his BSEE and MSEE degrees from North Carolina State University in 2014 and 2020, respectively. He is a registered professional engineer in the state of North Carolina and has worked at Duke Energy since 2014. Ethan has held positions as a protection engineer and, more recently, as the protection and control settings group manager.

Jackson Fultz received his Bachelor of Technology degree in Electrical Engineering from the University of North Carolina at Charlotte in 2023. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2022 as a power engineer intern in research and development and is currently working with the company full time as an associate protection engineer in government engineering solutions.

Arun Shrestha received his BSEE from the Institute of Engineering, Tribhuvan University, Nepal, in 2005 and his MS and PhD in electrical engineering from the University of North Carolina at Charlotte in 2009 and 2016, respectively. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2011 as an associate power engineer in research and development. He is presently working as a senior engineer. His research areas of interest include power system protection and control design, real-time power system modeling and simulation, wide-area protection and control, power system stability, and digital substations. He is a senior member of IEEE and is a registered professional engineer. He is a member of the IEEE Power System Relaying and Control Committee and a U.S. representative to IEC 61850 TC 57 WG 10.

Arunabha Chatterjee received his BTech from the National Institute of Technology Karnataka, India, in 2014. He received his MS in Electrical and Computer Engineering from the Georgia Institute of Technology in 2015. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2016 as an associate power engineer and is currently working as a lead power engineer in research and development.

Priyanka Nadkar received her Bachelor of Technology degree in electrical engineering from the University of Mumbai in 2012 and her MS in electrical engineering from North Carolina State University in 2014. She joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2015 as an associate integration and automation engineer and is currently working as a development lead integration and automation engineer in research and development. She is a member of IEEE Power System Relaying and Control Committee, Power System Communications and Cybersecurity Technical Committee, and a U.S. representative to IEC TC 57 WG 10.

20230911 • TP7124-01