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Abstract—**This paper documents a collaborative effort to design a centralized protection and control (CPC) system for an existing two-bank substation, with the goal of leveraging the benefits of the new technologies. Because of its simplicity and numerous other benefits, a point-to-point-based CPC system is selected in this case study. One of the goals is to develop a repeatable solution that can be used at many locations with minimal modification. The CPC system is compared against the existing protection and control (P&C) system by using total device count, device settings, and protection system operational speed of the transformer and bus differential protection elements. This paper contains a discussion of the utility perspective, exploring issues of potential benefits, design questions, and technical challenges.**

I. Introduction

The electric grid is undergoing major expansion because of rapid growth of inverter-based resources in both transmission and distribution (T&D) sectors. As the grid continues to expand to support the growing energy needs, the reliability of the energy supply becomes even more critical. To operate the evolving grid, the protection and control (P&C) systems should be flexible and ready to accommodate future growth. From a utility's perspective, utilities must design and install new P&C systems for forthcoming substations. At the same time, utilities still have hundreds of old substations that contain outdated electromechanical and microprocessor-based P&C systems that must be upgraded. In recent years, there have been drastic advancements in computing technology, fiber optics, and communication networks in the P&C system. These advancements have led to renewed interests in centralized protection and control (CPC) systems for substations. The CPC system aggregates P&C functions of several relays into a single hardware, with potential benefits like increased flexibility and reduced costs. Similarly, utilities have been looking into digital secondary systems (DSS) to replace copper cables used in P&C systems with a few fiber-optic cables. All these technological innovations have helped utilities evaluate CPC systems as a new P&C system for their T&D substations [1] [2].

Duke Energy has expanded the use of fiber optics in various aspects like protection, control, alarming, and communication schemes. However, copper cables continue to be used to connect current transformers (CTs) and potential transformers (PTs) to protective relays and metering devices. The viability of deploying a point-to-point digital secondary system (P2P DSS) to replace these copper cables in substations is being explored [3]. Furthermore, Duke Energy is investigating CPC technology to reduce the number of devices in a substation. Fewer devices mean fewer relay models for installation, commissioning, configuration, testing, operation, and inventory management. As the CPC system has access to analog and binary signals from throughout a substation, its event record simplifies disturbance analysis. Recent efforts have explored the potential use of a P2P-based CPC system for its simplicity, potential cost savings in substation construction, and reduced construction time [1] [2].

To further explore the benefits and challenges of a CPC system on complex distribution substations, this case study is a collaboration between each author's company. This paper describes the detailed design of a simple P2P-based CPC system tailored for an existing two-transformer distribution substation at Duke Energy. The design uses P2P merging units (MU) and P2P CPC units available from an IED manufacturer to protect and control the entire substation. Each CPC unit protects one transformer, one low-voltage bus, and their associated feeders. To eliminate a single point of failure, two CPC units are used for each transformer. Two P2P-based CPC system designs are presented, one with complete MU redundancy and another with limited MU redundancy. The P2P MUs do not require any user settings. As a result, in the new design, only CPC units require configuration compared to all relays in the existing substation. Similarly, this paper includes quantitative data on device count and device settings for the existing substation and a P2P-based CPC system. Test results that demonstrate the performance of a transformer and bus differential protection in existing relays and the CPC system are presented. Furthermore, the paper delves into the utility's perspective, exploring issues of potential benefits, design questions, and technical challenges. This paper also discusses the utility's perspective on the concerns and risks associated with the level of centralization, potential failure modes, and change management requirements for engineering and testing that apply to general centralized design.

II. Distribution Substation Protection at Duke Energy

Protection and control designs on transmission to distribution (T/D) substations at Duke Energy have remained relatively consistent, and "standardized" panels have been used with minimal modifications for the past 30 years. Standard transformer bank panel solutions have been used that allow for station growth and expansion as additional transformers are added over time. Typically, most T/D substations grow and expand to two or three transformers with some expanding to as many as four. Transformer bank panels have been designed with back-up protection so that any single relay failure will not require the removal of the transformer from service. This approach typically used a high-side overcurrent relay, a transformer bank differential, a low-side bus differential, and a low-side overcurrent relay. Distribution circuit exits have used a standard protection package for each circuit. Fig. 1 shows an example one-line drawing illustrating the protection in a T/D substation.

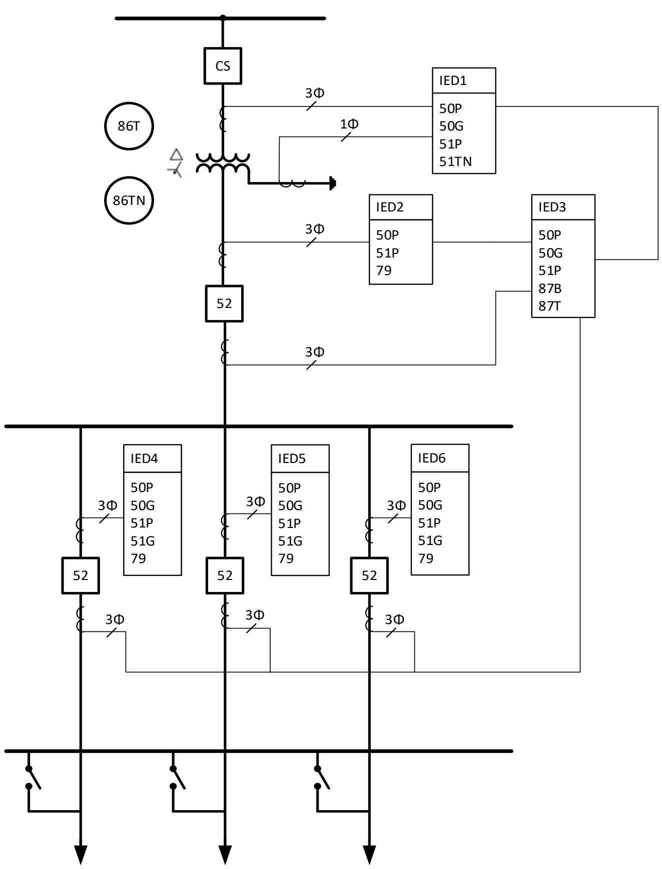

Fig. 1. Traditional single-transformer distribution substation.

With all protection devices in service, fast protection is maintained within the substation. A transformer differential uses the bushing 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 by 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. Combined overcurrent differential protective elements have been used for implementation of the bus differential. In recent years, a definite-time characteristic has replaced the use of inverse time-delay overcurrent. A single protection panel was used for each transformer and bus section. All distribution circuit exit relays were installed on an additional panel, one panel per bus section. Engineered into the standard bank panel design was the ability to include additional functionality that would be required when additional transformers were installed into the substation.

When a T/D substation expands with an additional transformer, an additional low-voltage bus section along with a bus tie breaker is added to facilitate operation flexibility when performing maintenance. This allows for additional automated functionality. A two-transformer T/D substation is illustrated as shown in Fig. 2 (along with its required protection). The additional automated functionality includes:

- Automated bus transfers upon 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 picking up the load from the low-voltage bus of the failed transformer.
- Automated load shedding following an automated bus transfer—Following a successful bus transfer, the low-side protection on a healthy transformer requires the additional functionality of ensuring that the additional load does not overload the remaining emergency ratings of the transformer. This is done through load-shedding protection within the overcurrent relay on the low-side breaker.

When a bus tie breaker is installed, an additional intelligent electronic device (IED) is also installed. This IED is used for the implementation of SCADA control for the bus tie breaker along with providing meter quantities. When substations contain three (or more) transformers and bus sections, tie breaker statuses are communicated between the bus tie IEDs to facilitate the control of automated swapovers.

Fig. 2 also illustrates additional components that are commonly found in Duke Energy's T/D substations. These include the following:

- Low-side auxiliary breaker: This breaker is used to facilitate the safe operation and maintenance of the distribution circuit exit breakers while providing and maintaining safe protection to distribution feeders during their use. Not all T/D substations have an auxiliary breaker, but they are commonly found in substations with substantial load. When an auxiliary breaker is installed, usually one is used for the entire substation.
- Capacitors: The capacitor IED requires extensive programming/control logic and local operator interface. Capacitors are commonly installed for voltage support and power factor improvement. One or two steps of capacitors are routinely installed in a bus section.

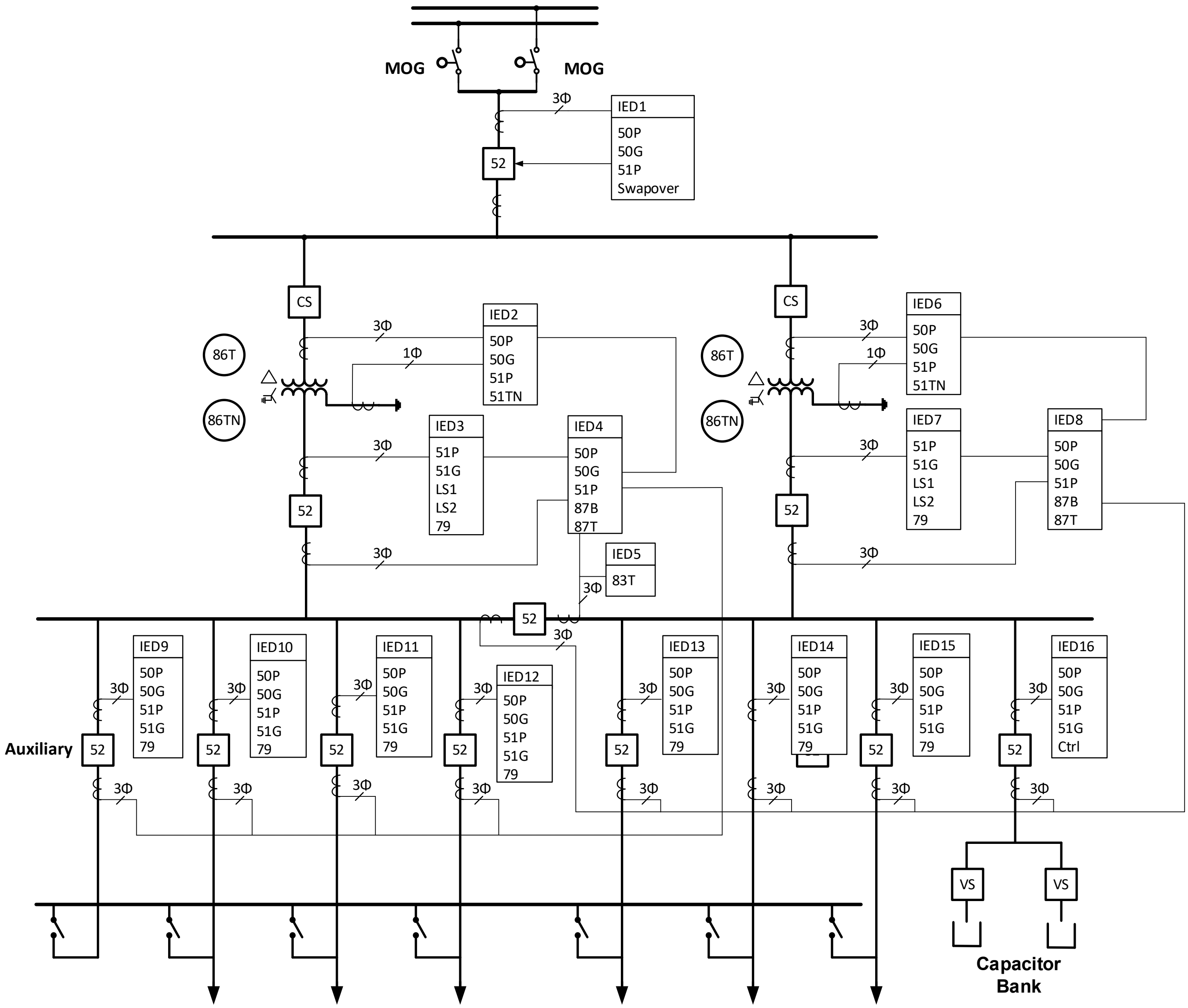

Fig. 2. Two-transformer distribution substation with bus tie breaker, auxiliar breaker, capacitor, and high-side swapover.

- High-side breaker with a swapover: While many of these swapovers are found in older substations, they are not commonly installed in new substations. Anytime a substation high-voltage breaker is installed to provide protection for the high-voltage bus, overcurrent protection is required. When motor-operated switches/gangs (MOG) are installed to implement swapover functionality, the IED used for the breaker also contains the additional logic and control to implement the swapover. The swapover control requires extensive programming and control logic.

For the evaluations made in this document, we use the substation design illustrated in Fig. 4. While distribution circuit exits typically vary from one to four per bus section, each low-voltage bus section contains two. An auxiliary breaker is included along with a high-side swapover.

III. P2P DSS and CPC System

In a traditional substation, large amounts of copper cables are used to exchange analog and binary signals between primary equipment and P&C devices. A traditional substation requires thousands of individual connections between P&C devices that require termination individually by skilled workers [4]. As a result, traditional secondary systems are costly and require extensive installation, commissioning, and testing time. In DSS, signals that originate from primary equipment are digitized using MUs and are forwarded to P&C devices. This solution eliminates copper cables between primary equipment and P&C devices and replaces them with a few fiber-optic cables, potentially leading to lower substation construction costs and reduced construction time. In a P2P DSS, an MU is directly connected to a P&C device by using a fiber-optic cable. Because a P2P DSS does not require additional network devices like ethernet switches and clocks, simplicity is its prominent strength.

A CPC system aggregates all P&C applications in a few devices with the goal of improving the reliability of P&C systems while reducing design costs. Although CPC systems have not seen much use, the concept of CPC is not new. CPC systems have been implemented in the field in the past [5]. However, with the advancements in processing power of P&C devices and maturity of DSS technology, CPC systems are making a revival. A CPC system can be hardwired, P2P-based, or IEC 61850-based [1]. In this paper, we focus on a P2P-based CPC system.

Fig. 3 shows a schematic diagram of a P2P-based CPC system communicating with multiple P2P MUs. In this system, 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. This design is well-suited for small- to medium-sized substations. The advantage of this design is its modularity and ease of expansion. If more bays are added, then MUs can be installed relatively easily in the switchyard; the MUs are then connected to the CPC device. However, a CPC device has a limited number of communications ports, thus future expansion must 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 and replacement.

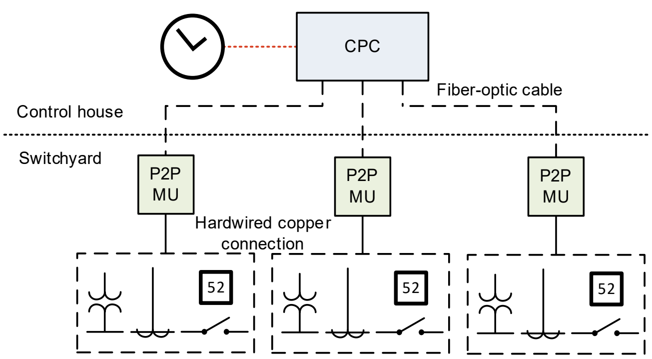

Fig. 3. Simple P2P-based CPC system.

IV. Duke Energy's Perspective on a P2P-Based CPC System

A. Potential Benefits

CPC designs offer the following possible strategic advantages over the traditional protection designs for T/D substations.

1) Reduced number of devices.

The most obvious benefits from a CPC system are a direct result of the reduced number of protective devices required. Using fewer devices results in managing and installing fewer relay models in the substation. This translates to the following benefits:

- Reduced variety of devices required in inventory—The historical T/D substation design uses three different relay models. The CPC system uses one relay model.
- Reduced number of devices to test and commission.
- Reduced panel wiring (inter-relay wiring)—Using a P2P DSS has the additional benefit of replacing a significant amount of copper conductors.
- Reduced amount of panel space, allowing the use of a smaller control enclosure for the substation.
- Reduced complexity in settings and software.
- Reduced effort and complexity for firmware upgrades.
- Reduced number of settings templates to be maintained—With the reduced number of devices installed, there is a reduced number of settings templates applied and tested by the field. Theoretically, if a two-CPC device approach is implemented, it uses no more than two core setting templates. One setting template would be used with the control functions enabled in one CPC device and turned off in the other.

2) Reduced commissioning time.

3) Simplified SCADA communications as the number of devices is reduced.

4) Centralized disturbance fault recorder (DFR) and sequence of events (SOE).

These potential benefits can also bring new technical challenges. We must carefully consider how to best address these challenges before implementing a CPC system. Use of a human-machine interface (HMI) would be required to efficiently address many of the substation operational challenges. However, use of an HMI introduces new technical issues.

B. Technical Challenges

1) Implementation of Multiple Settings Groups

Traditional Duke Energy practices for circuit exit feeders use multiple settings groups to account for cold-load pickup or for carrying multiple circuits temporarily on one breaker. This would be required for any new CPC design moving forward. In addition to this practice on circuit exits, the high-side swapover scheme on the Duke Energy system also uses multiple settings groups based on which source is considered preferred by the operators. The possible combinations of settings group requirements that can be required, or the extra programming that may be needed to replace the settings group shifts, will require very careful analysis and programming to ensure that the CPC system does not introduce additional human errors or unnecessary settings maintenance, while maintaining the functionality expected by system operators and technicians.

Keeping the settings groups in synchronization between CPC units becomes a necessity. Use of an HMI to facilitate this challenge would assist the operator. When replacing a failed CPC unit, procedures would need to be implemented to get both CPC units synchronized with all combinations of multiple settings groups.

2) Control Logic With a Redundant CPC Approach

Control logic within the protective relays would normally only be performed by the primary relay, so the first thought is to have the pure control logic (reclosing, swapover control, bank transfer, etc.) only programmed in the primary CPC unit. However, if the primary CPC unit were to fail, the control for the entire substation would be lost, whereas in a traditional scheme, the loss of one control relay may only remove the ability to control one function. Controls must be programmed redundantly, with a bypass function so the backup CPC unit does not perform the control functions unless the primary is out of service. In normal operation and commissioning, it might not be a challenge to keep the control logic synchronized between CPC units. However, during a CPC unit failure or replacement, the current state of control within the substations must be made the same in both CPC units.

3) SCADA Implementation

If a single CPC unit provided all the SCADA for a single transformer and low-voltage bus section (including circuit exits), failure of one CPC unit would place system operators in a blind position (no data flowing from this transformer and all its circuit exits, etc.). With this risk, the need for redundant SCADA may become a necessity. This brings many new design challenges associated with redundant SCADA in order to prevent creating additional problems and issues. Careful thought is needed on how to implement the SCADA redundancy with the control centers.

4) Operational Complexity and Operator Interface

Historically, substation operators performed numerous job functions on the front of the individual relays. Centralized protection devices necessitated the need for an HMI to perform the local operating functions. Following is a list of the main functions these operators would normally perform:

1. *Blocking protective elements when performing substation switching*. This might include blocking reclosing or blocking ground protective elements while performing switching procedures.
2. *Local open/close of a breaker*. Current practice is one pushbutton for open and a different pushbutton for close on a single relay for each switching device (a breaker or a circuit switcher) in a T/D substation.
3. *Obtaining relay targets after an event*. Unless a CPC unit has a very high number of target lights, an HMI is needed to display event targets for the local operators. With proper SCADA programming and commissioning, relay target information should not be an issue for control center operators.
4. *Changing settings groups*
    - Traditionally, each distribution circuit exit breaker has two settings groups available: one for normal operation and one for cold-load pickup or carrying multiple circuits.
    - Each transformer bank protection panel would also typically have two settings groups, one for normal operation, and one for a substation differential when the low-side bus breaker is bypassed.
    - A high-side swapover scheme typically has four settings groups that modify how the swapover controls are operated (swapover off, source 1 preferred, source 2 preferred, or neither preferred).

Relying on an HMI introduces additional challenges. In an emergency, there is no longer a button on the front of the relay to quickly open a breaker; HMIs require passwords and screen navigation. Currently, two types of operators can 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 that a control center "block reclosing" or apply "hot line tag" to a circuit, they would no longer have the front of a relay to check and verify this functionality has occurred but would need to be comfortable confirming through the HMI (which requires that they have access to).

5) Challenges and Procedures Required for Replacement of a Failed CPC Unit

In the event of a failed CPC unit, the process for replacement and commissioning is different from a traditional relay. The outputs from the CPC unit need to have a software block to test the functionality of the device without causing an operation, whereas traditional relays have test switches that can provide a visual open point during the commissioning after a relay failure.

6) Required Lab Testing

The use of a P2P-based CPC system requires a significant change management plan and extensive lab testing prior to implementation.

7) Training and Personnel Development

Proper training of relay technicians and operators is necessary for the utility to successfully navigate these challenges. Any change should follow the historical approach of being deliberate and well thought out before implementation. In particular, the application of merging units and the lack of test switches causes the biggest changes and challenges to field personnel.

C. Design Questions

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

Some of the important design considerations are as follows:

a) Redundancy of CPC units becomes a necessity—Historically, T/D substations use a backup philosophy, but this will change to full redundancy.
b) Standardization and repeatability—All distribution designs must be engineered with repeatability in mind. How repeatable is the design? Can the same design be used at substations with layout variations? Can the design be implemented with minimal customization in both design and settings?
c) Simplicity—Is the protection scheme easily understood by both the engineers that design it, the technicians that install it, and the operators that use it?

d) Will the CPC system design be relatively easy to install and test? How does this compare to other design options?
e) Ease of failed device replacement—Are the risks associated with replacing a failed device elevated with a CPC approach? Are they potentially lessened? Replacement of failed CPC units has the challenges of synchronizing the settings groups and control status of many functions. Working through these scenarios prior to actual implementation reduces unwanted surprise circumstances after placing a replacement CPC unit in service.
f) How does a P2P-based CPC system impact troubleshooting and maintenance? Migrating protection functions from devices external to the relay to logic internal to the relay moves troubleshooting efforts from wires and switches to troubleshooting logic. While this requires a change in troubleshooting procedures, it may make troubleshooting for the technicians easier in the long run, and future testing should become more automated.
g) How much can be placed into one CPC system versus how much should be placed into one CPC system? If more applications are required within a T/D substation (capacitor control for instance), can the existing CPC system support even more additional logic? Should these additional control functions be treated separately from the CPC system to maintain its repeatability, or is there a way to incorporate extra substation control functions without extensive reprogramming?
h) How is cost versus benefits evaluated? It appears that many of the potential benefits from a more centralized design would be obtained over time; once the utility starts to implement this approach, cost savings would be realized when "you get good at doing it". The centralized approach is new and will require change-management to achieve it.

When weighing the potential benefits with the technical challenges of a CPC system, it is crucial to carefully consider how many and how fast changes are implemented.

V. P2P-Based CPC System Design

This section describes the existing P&C system design implemented in the two-transformer distribution substation at Duke Energy. Protection philosophy for each protection zone and backup used is discussed. For this distribution substation, two P2P-based CPC systems are designed. The first design considers full redundancy for CPC and MUs. In the second design, only limited MU redundancy is considered to reduce the total number of devices. In both designs, Duke Energy's existing P&C philosophy is maintained. Some of the technical details of the CPC and MU used for the design are presented.

A. P&C System Design of an Existing Distribution Substation

The existing distribution substation consists of two delta-wye-grounded step-down transformers, tapped from 100 kV parallel transmission lines. Fig. 4 shows the single-line diagram of the distribution substation, along with P&C devices used. A single circuit breaker feeds the high-voltage side of both transformers. This circuit breaker is connected to one of the parallel lines via two motor-operated ganged disconnects. Each transformer (20 MVA) steps down the voltage to 12.5 kV and connects to the low-voltage bus. Motor-operated ganged disconnects are installed on the high-voltage side of the transformer, and circuit breakers are installed on the low-voltage side. Bank 1 and Bank 2 transformers feed three and two feeders, respectively. A bus-tie breaker is installed between two low-voltage buses. The bus-tie breaker allows feeders to be supplied from either transformer bank during transformer maintenance or in case of a transformer failure.

The tapped points on the 100 kV lines are protected using two overcurrent relays. Each transformer is protected using a high-side overcurrent relay, a transformer bank differential, a low-side bus differential, and a low-side overcurrent relay. The transformer differential relay also provides bus differential protection via a differentially connected overcurrent element. Each distribution feeder is protected using an overcurrent relay. The existing substation employs 13 relays of three distinct types for overall protection and control. These relays are installed in the control house in four panels. Furthermore, the existing P&C design uses four trip relays (94) and two lockout relays (86), which are not shown in the figure.

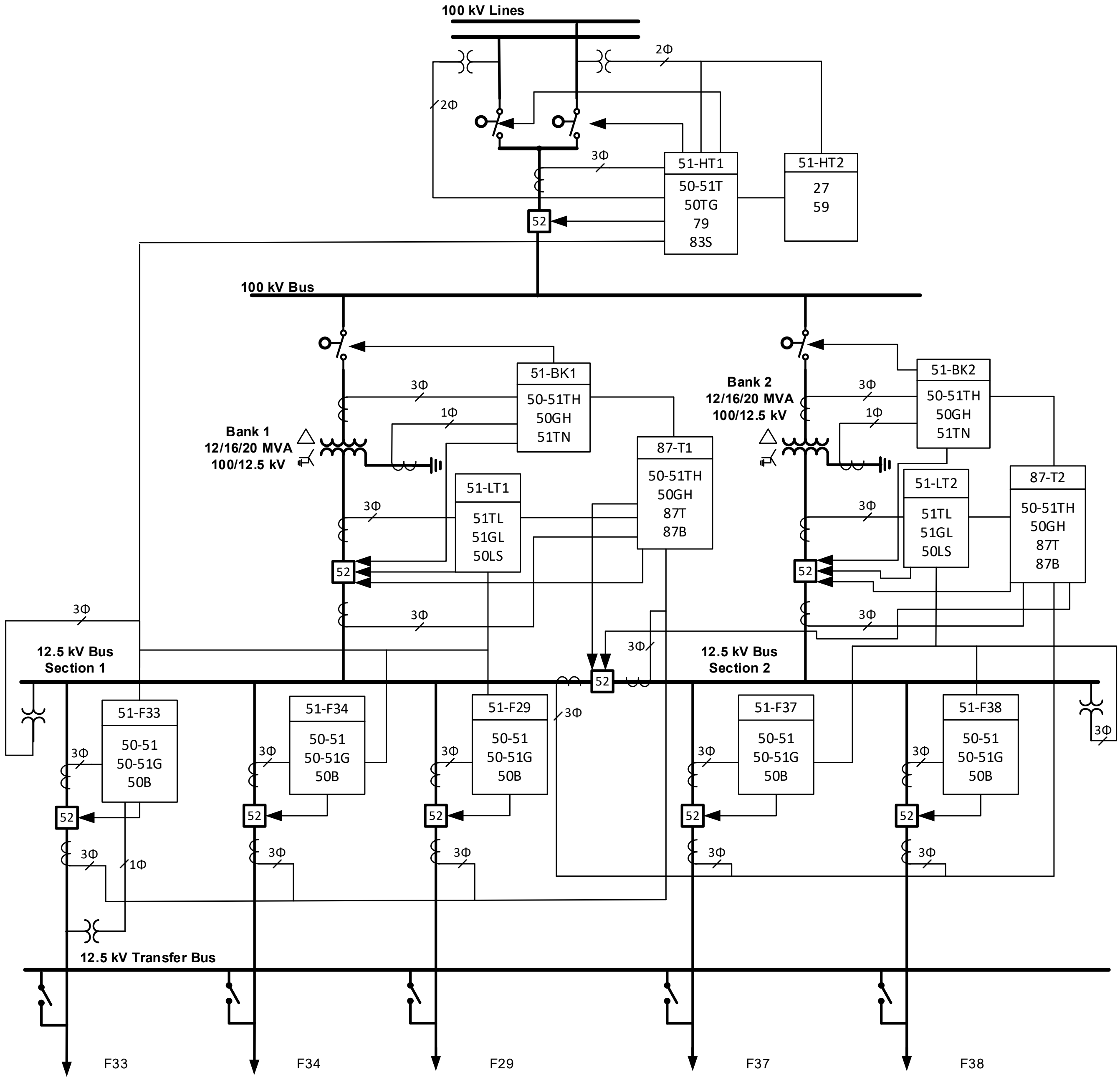

Fig. 4. P&C system of the utility's existing distribution substation.

B. P2P-Based CPC System Design I—Full Redundancy

For the distribution substation described above, the first P2P-based CPC system is designed considering full redundancy for both CPC units and MUs. P2P MUs and P2P-based CPC units offered by an IED manufacturer are used for the case study. Each P2P MU has four fiber ports and can communicate with four CPC units over a direct fiber-optic connection. These MUs do not require any user settings or firmware management. Similarly, each P2P-based CPC unit has eight fiber ports, allowing the CPC units to communicate with as many as eight MUs. Each CPC unit has access to all available signals in its connected MUs and can control its binary outputs. The MUs and the CPC units exchange analog and binary signals by using a manufacturer-specific, nonroutable protocol [3].

The first P2P-based CPC system design for the case study is shown in Fig. 5. Each MU and CPC unit is duplicated to provide full redundancy. Failure of a single MU or CPC unit has no impact on the protection system availability. Transformer Bank 1 and its associated feeders are protected using a set of CPC units. Similarly, a second set of CPC units protect Transformer Bank 2 and its feeders. This design requires a total of four CPC units and 18 MUs. The MUs are installed in the switchyard close to the primary equipment and the CPC units are installed in the control house. The four P2P-based CPC units can be easily installed in a single panel in the control house. Although the total number of devices are higher in this design, only the P2P-based CPC units require user configurations.

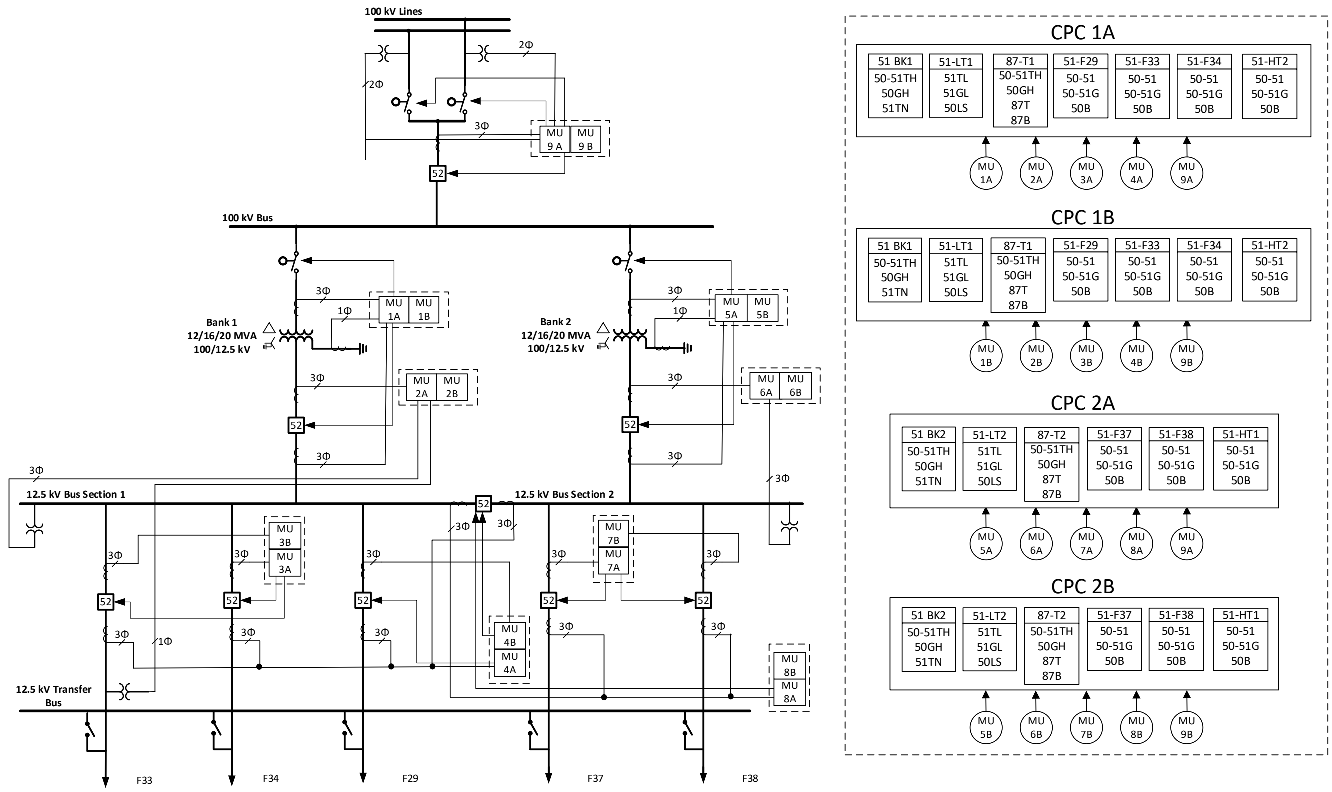

Fig. 5. P2P-based CPC system design with full redundancy.

C. P2P-Based CPC System Design II—Limited MU Redundancy

Fig. 6 shows the second P2P-based CPC system design for the same distribution substation where the MU redundancy is limited to a few critical MUs. The philosophy behind this design is to reduce the total MU count without jeopardizing overall protection availability of the substation. MUs on the high-voltage side and CPC units are designed with full redundancy. In the event of failure of nonredundant MUs, the CPC units will deenergize the respective transformer bank and its associated feeders. This design requires a total of four CPC units and 12 MUs, reducing the MU count by six. The panel requirements for CPC units in the control house remains the same.

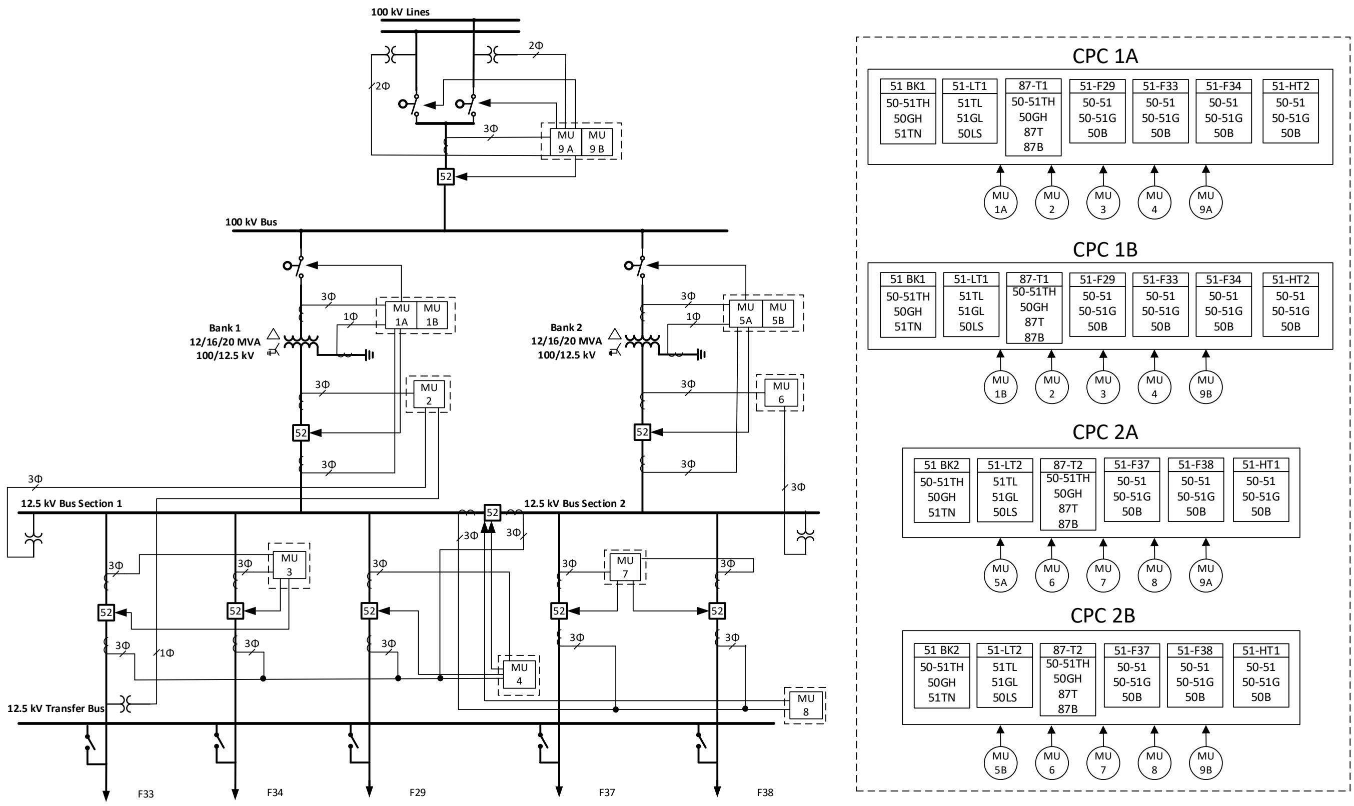

Fig. 6. P2P-based CPC system design with limited MU redundancy.

VI. Comparative Analysis

In this section, we compare the existing P&C system design with two P2P-based CPC system designs analytically. For comparative analysis, we used device count, device settings, and protection system operation speed as metrics. The data provided in this section highlight the benefits and challenges of each design. Such technical data are invaluable in the decision-making process when selecting a CPC system.

A. Device Count

The number of P&C devices in a substation has significant impact on substation design, installation, commissioning, operation, and maintenance. As the number of devices grows, it has direct impact on capital expenditure and maintenance costs. In the case of existing P&C design, a higher number of devices requires extensive and complex wiring, multiple relay panels, and a larger control house. It is labor intensive to commission, test, and maintain such designs. When large numbers of P&C devices of different types are used, asset management and maintaining spare devices becomes costly and challenging [2].

In P2P-based CPC designs, MUs are installed in the switchyard close to the primary equipment, and CPC units are installed in relay panels in the control house. Depending on the utility's preference and the space available in primary equipment cabinets, MUs can be installed in existing cabinets in the switchyard or in dedicated cabinets. For P2P-based CPC designs, the number of panels and the size of the control house is smaller. The direct fiber connection between the MUs and the CPC units makes the design simple to understand, install, test, troubleshoot, and maintain.

Table I shows all devices used in the existing P&C design and the two P2P-based CPC designs discussed in Section V. The existing design uses 13 relays of three different types, 4 trip relays, and 2 lockout relays. The relays are installed in four panels in the control house. The protection of the overall substation is spread out in the 13 relays, which makes the design inherently complex. Proper coordination between relays and peer-to-peer communication are typically used in such designs. In the P2P-based CPC Design I (Fig. 5), 4 CPC units and 18 MUs are required. The number of devices for this design is higher than the existing design. This design does not require separate trip relays or lockout relays because the functionality is implemented in the CPC logic. The four CPCs are installed in one panel, rather than in four separate panels in the existing design. Use of redundant MUs and CPC units provides better protection scheme unavailability compared to the existing design [1]. Hence, this design requires less panel space, uses a smaller control house, provides improved protection scheme unavailability, and uses a simpler design.

In the P2P-based CPC Design II (Fig. 6), 4 CPC units and 12 MUs are required. Between the two P2P-based CPC designs, this design lowers the MU count by six. The control house and panel requirements for this design are the same as that of the previous design. Absence of redundant MUs on the low-voltage side of the distribution substation increases the protection scheme unavailability. Loss of a CPC unit has no impact on the overall protection. However, loss of a nonredundant MU will result in tripping one transformer and its associated feeders. Such a design can be considered for noncritical feeders.

TABLE I
DEVICES USED IN EACH DESIGN

Device	Existing P&C Design	P2P-Based CPC Design I	P2P-Based CPC Design II
Transformer Relay	2	0	0
Overcurrent Relay Type I	9	0	0
Overcurrent Relay Type II	2	0	0
Trip Relay (94)	4	0	0
Lockout Relay (86)	2	0	0
P2P-based CPC Unit	0	4	4
P2P MU	0	18	12
Relay Panel	4	1	1

B. Device Settings

When microprocessor-based relays are used for protection, utilities need to track and maintain multiple file types for each relay. Relay firmware, settings templates, protection settings, and automation settings files are typically version controlled and stored securely. For each relay type used, the utility needs to maintain its firmware information and settings template (when templates are used). Similarly, for every relay in the substation, its protection and automation settings files are stored in a version-controlled relay database. Hence, as the number of relays and relay type increases in the substation, managing all these files becomes challenging.

Every year, the North American Electric Reliability Corporation (NERC) releases a state of reliability report in which it lists protection system operations and misoperation counts in its region. For misoperations, NERC categorizes them by various causes. Fig. 7 shows the percentage distribution of misoperations by cause, for a total of 1,131 misoperations for the year 2023 [6]. Year over year, the leading cause of misoperations has been incorrect settings. In 2023, incorrect settings and logic errors were responsible for 26 percent of the total misoperations. Hence, lowering the settings count and simplifying both protection and logic settings can aid in reducing misoperations.

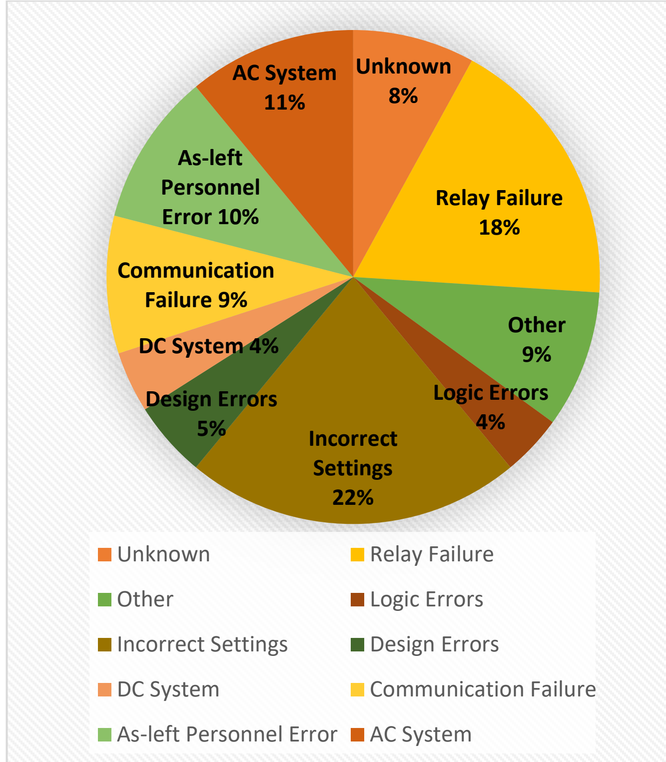

Fig. 7. Percentage of misoperations by cause (NERC 2023).

In the existing substation, 13 microprocessor-based relays of three different types are used for protection. For overcurrent relay Type I, three different part numbers are used. As a result, the utility needs to maintain the firmware version of each relay. Similarly, settings files for all 13 relays require secure storage and version management. Table II tabulates the group settings, nongroup settings, and total settings for each device in the utility's distribution substation. Only the settings values that are different from the defaults are counted. The group settings refer to protection and logic settings set in multiple settings groups. Similarly, nongroup settings refer to the rest of the settings in global, ports, SOEs, DNP maps, etc. The total settings count for the entire substation is 3,954, out of which 32 percent of the settings are not directly related to protection and logic.

TABLE II
SETTINGS COUNT IN EACH DEVICE IN THE EXISTING SUBSTATION

Device	Group Settings	Nongroup Settings	Total Settings
51-HT1	475	398	873
51-HT2	113	306	419
51-BK1	98	26	124
87-T1	184	69	253
51-LT1	112	39	151
51-BK2	57	67	124
87-T2	177	76	253
51-LT2	111	37	148
51-F33	328	46	374
51-F34	257	46	303
51-F29	263	52	315
51-F37	260	46	306
51-F38	263	48	311
Total	**2,698**	**1,256**	**3,954**

The P2P-based CPC system described earlier uses MUs and CPC units for overall substation protection and control. The P2P MUs used do not require any configuration. In other words, they do not require device settings or firmware maintenance. On the other hand, only one device type is used for all four CPC units in the proposed designs. Using only one device type simplifies management of firmware updates, settings templates, cybersecurity patches, and settings files. In the P2P-based CPC system design, redundant CPC units are used. Between each redundant CPC unit, most of the settings are identical. This helps to lower settings differences in multiple settings files. In the P2P-based CPC system design, CPC unit 1A and CPC unit 2A provide the P&C functionality previously provided by six and seven distinct relays in the existing substation, respectively. Because the nongroup settings shown in Table II are somewhat common between multiple relays, these settings are needed only once in the CPC unit. If we keep group settings the same and assume the reduction of nongroup settings by a factor of 5, the nongroup settings in the P2P-based CPC system can be reduced from 1,256 to 251. This reduces the total unique settings count of the P2P-based CPC system A from 3,954 to 2,949, a reduction of 1,005 unique settings. Note that the P2P-based CPC system B will have identical settings for protection because of the redundant design.

The P2P-based CPC system provides other techniques to reduce the settings count. It includes advanced functionality to dynamically include or exclude terminals from the transformer and bus differential protection. Similarly, pickup and time-dial settings for overcurrent elements can be dynamically updated. Such advanced functions are not available in the existing relays, which forces the user to configure multiple settings groups. In most applications, only a few settings are changed between settings groups. Hence, some settings groups can be avoided in the CPC units, which can help further lower the setting counts.

Fig. 7 also shows 18 percent of misoperations are a result of relay failures. Use of redundant units in the P2P-based CPC system design can help lower misoperations for this cause. In summary, with the P2P-based CPC system design, the number of relay types, relay firmware, settings files, settings, and relay failures are reduced. These reductions help the utility manage and maintain these devices efficiently and result in fewer misoperations.

C. Protection System Operation Speed

In this subsection, we compare the protection system operation speed of the transformer differential element (87T) and the bus differential element (87B) between the existing P&C device and the P2P-based CPC system design. Duke Energy's P&C system is designed to provide fast protection during faults. Fast protection speed results in reduced fault-clearing time. When faults are cleared faster, it enhances personnel safety, limits equipment wear and damage, and improves the power quality. For a utility to consider any new P&C design, it is essential that the design provides comparable or faster protection speed than the existing design.

In the existing design, analog signals from the CT and PT are supplied to the relay via copper cables. Similarly, the trip signal from the relay is transmitted to the circuit breaker through copper cables. Hence, the signal latency is negligible in the existing design. The protection speed of the relay depends on the protection algorithm, processing rate of the relay, and type of output contacts (high-speed or standard speed) used. In the P2P-based CPC system design, the MU digitizes analog signals and sends them to the CPC unit. Similarly, the CPC unit sends a trip signal to the MU, which then closes its output contact to open the circuit breaker. In the case of P2P-based CPC system design, protection speed depends on the CPC unit protection algorithm, the processing rate of both the CPC unit and MU, the signal latency between the two devices, and the MU output contacts. Next, we show the test results from the existing relay and the CPC unit to compare the protection speed of the two.

1) Transformer Differential Protection

Transformer differential protection relies on the principle of ampere-turns balance to create a protective zone around the transformer. In this approach, CTs from all sides of the protected equipment provide measured currents to the relay. These currents are then used to calculate operate and restraint values. The operate quantity represents the sum of the currents entering the zone, while the restraint quantity reflects the total current through the zone. The percentage-restrained differential characteristic consists of a minimum operate current and a slope value that represents the percentage ratio of operate-to-restraint current. If the operating point falls within the internal fault region, the differential protection activates, indicating a transformer internal fault.

To evaluate the protection speed of the 87T element, we tested it by using a microprocessor-based transformer relay in the existing substation. The selected transformer relay executes protection algorithms four times per power system cycle and only includes standard output contacts for tripping. Similarly, the MUs and the CPC units used in the P2P-based CPC system design are used for testing. The CPC unit executes protection algorithms eight times per power system cycle and exchanges analog and binary signals with the MU at 10 kHz. The P2P MUs have high-speed output contacts, which are used during the test. Both P&C systems are wired in parallel so that the 87T elements in both systems receive the same currents. Settings from the existing substation are applied to the transformer relay and the P2P-based CPC unit. Using a real-time digital simulator and external amplifiers, fault currents that correspond to the transformer internal faults are applied and the trip signals are measured. The time difference between the fault initiation and the 87T element operation (i.e., round-trip time) is measured in the simulator. This test was repeated 100 times. Fig. 8 shows the round-trip time of the 87T elements in both systems. Each blue circle represents a test point, and the black circle represents the average operation time. The variation of blue circles along the X-axis corresponds to the frequency of the 87T operation time occurring within a specific time indicated on the Y-axis.

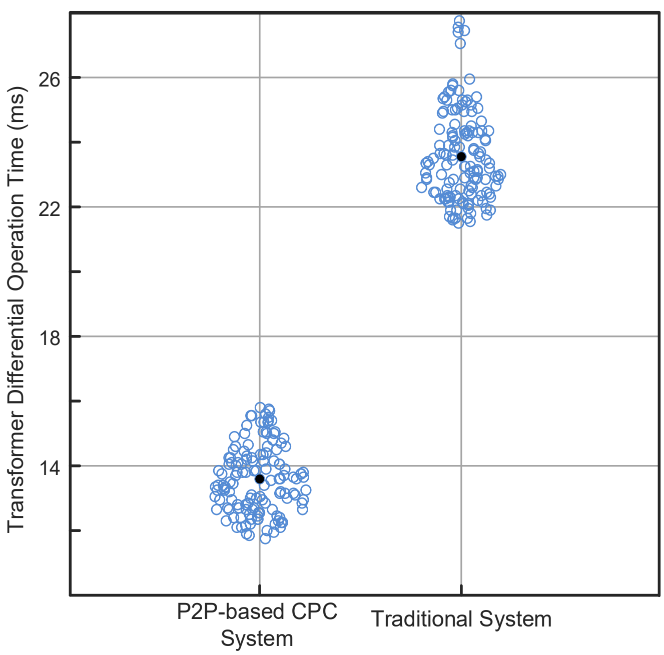

Fig. 8. Round-trip times of the 87T element in the traditional system and the P2P-based CPC system.

Table III shows the average round-trip time for each system. The P2P-based CPC system average operation time for the 87T element is 13.59 ms, compared to 23.55 ms for the transformer relay in the traditional system. This protection speed difference is because of its slower processing rate and the absence of high-speed output contacts in the traditional system.

TABLE III
AVERAGE ROUND-TRIP TIME (MS)

Solution	87T Element	
	Operation Time (ms)	**Difference (ms)**
P2P-based CPC system	13.59	NA
Traditional system	23.55	9.96

2) Bus Differential Protection

The bus differential protection operates like the transformer differential protection element. It combines the scaled currents from all CT inputs mathematically to detect fault currents resulting from internal faults within the protection zone defined by the CTs connected to the relay. Additionally, the relay calculates the sum of the current magnitudes to create a restraint current, accounting for minor variations in CT performance. The operate current, resulting from vectorial current summation, is compared with the restraint current. The relay activates when the operate current exceeds both a minimum threshold and a percentage of the restraint current, as determined by an adjustable slope setting.

In the existing design, both the transformer differential and bus differential protection are implemented in a single transformer protection relay. The bus differential protection is provided using a differentially connected overcurrent element. All bus zone currents are summed, and an inverse time-overcurrent element is applied to the summed differential current for the low-voltage bus protection. Note that because the bus protection is an overcurrent element (51) and not a bus differential element (87B), the speed advantage is lost and the fault clearing times become proportional to the fault currents. Thus, a higher resistance bus fault can take longer to clear using a time overcurrent element than if a differential protection element was being used. As a result, during a bus fault, through-fault current passes through the transformer for a longer time, increasing its wear. Adding a separate bus differential protection relay (87B) for high-speed bus fault protection is not a part of the utility's protection philosophy for a distribution substation.

In the proposed P2P-based CPC system designs, all bus zone currents are available to the CPC units. Additionally, the CPC units used for this case study include both transformer differential protection (87T) and bus differential protection (87B) functions. As a result, the P2P-based CPC system can provide faster protection for bus faults compared to the overcurrent elements used in the existing system. To compare the operation speed of differentially connected overcurrent element (51) in the existing system and a dedicated bus differential element (87B) in the P2P-based CPC system, we simulated a bus fault with 0.9 ohms fault resistance and applied the fault currents to both systems. Settings for differentially connected overcurrent are taken from the existing relay, which uses US inverse U2 curve. The bus fault was applied 100 times and a round-trip time for each system was recorded. Fig. 9 shows the round-trip times for bus differential protection in the existing system and the P2P-based CPC system. Each blue circle represents the operation time for a test and the black circle represents the average operation time.

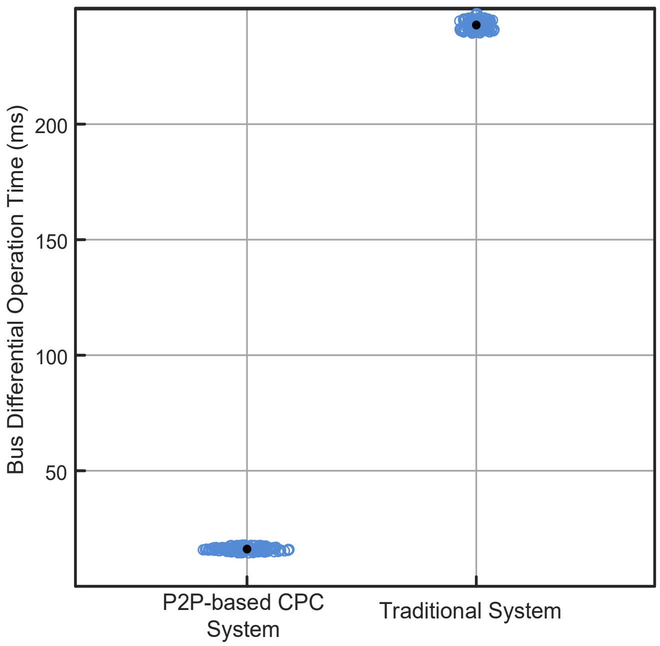

Fig. 9. Round-trip times of bus differential protection in the traditional system (51) and the P2P-based CPC system (87B).

Table IV shows the average bus differential protection operation speed for each system. For the given bus fault, it takes around 16.11 ms to clear the bus fault by using the P2P-based CPC system. On the other hand, using the differentially connected overcurrent element of the existing system, it takes around 242.90 ms. The dedicated 87B element in the P2P-based CPC system is faster by 226.79 ms or by a factor of 15.

TABLE IV
AVERAGE ROUND-TRIP TIME (MS)

Solution	Bus Differential Protection	
	Operation Time (ms)	**Difference (ms)**
P2P-based CPC system (87B)	16.11	NA
Traditional system (51)	242.90	226.79

Power transformers are the most expensive equipment in a distribution substation. If damaged, it can take from weeks to months to replace them. During a bus fault, through-fault current flows through the transformer. When considering the protection of power transformers, the impact of through-faults on the life of the transformer must be weighed because they produce physical forces that cause insulation compression, insulation wear, and friction-induced displacement in the winding. These effects are cumulative and should be considered over the life of the transformer. The damage to the transformer because of through-fault is calculated by computing the total I^2t value, where I is the through-fault-current and t is the fault duration [7]. Because the fault current for both systems is the same, the fault clearing time is the only differentiating factor. As shown above, the dedicated 87B element in the P2P-based CPC system can clear bus faults 15 times faster than the traditional system and reduces transformer damage by the same factor. Note that the operation time shown in Table IV does not include breaker operate time. Because the operation speed of 87T and 87B elements are much faster in the P2P-based CPC system than in the existing system, the proposed P2P-based CPC system significantly lowers damage to the transformer during internal transformer faults and through faults.

VII. Lessons Learned and Future Plans

There are a number of potential benefits offered by a P2P-based CPC system for T/D substations. The number of programmed or configured devices drops to two per transformer bank. While the number of devices increased significantly with the use of MUs, the MUs used in the P2P-based CPC system studied requires no configuration or settings. With the significant reduction in the number of devices that require configuration comes reduced engineering, testing, and commissioning time. Most of the potential benefits outlined in Section IV are a direct result of programming and configuring fewer devices, available with a P2P-based CPC system design.

Protection, reliability, speed, and improved protection capabilities are obtained by using a P2P-based CPC system approach for T/D substations. This study illustrated opportunities for speeding up transformer and bus differential protection. Faster fault detection and clearing helps improve personnel safety and reduces wear and tear on the components within the substation. This includes the through-fault damage incurred on expensive assets like substation transformers.

With all the potential benefits and gains, additional new challenges will be introduced with the implementation of an HMI to facilitate many of the current operational functionality of relays. Many of the operating functions currently performed on the front of the relay will move to the HMI. This includes opening and closing breakers from an HMI instead of a pushbutton. Obtaining relay targets from LEDs on the front of the relay will move to a virtual front panel in the HMI. The old method of switching settings groups and blocking protective elements will move from a pushbutton on the front of the relay to an operational screen on the HMI. Changes of this significance can be challenging to successfully implement and require a robust change management plan (CMP) that engages all stakeholders in the utility.

Plans are to proceed with a phased approach and proof of concept installation. Initial steps will begin with lab testing at the utility and with development of standard drawings and templates for a P2P-based CPC system. Lab testing will engage the field personnel to incorporate their feedback and input into new concepts of MUs and testing CPC systems. Operating service technicians also need to be engaged in the development process to ensure all operating functions such as blocking protection elements, changing settings groups, and obtaining relay targets, are successfully implemented in a new design. The initial installation would probably be installed in a single transformer bank T/D substation and the redundant CPC system would be placed in parallel with a traditional protection and control scheme. Development of an HMI must be included in the scope of any CPC system. As with all new protection and control systems, the design will be engineered to be repeatable and expandable to a multiple transformer installation.

VIII. Conclusion

Multiple transformer bank T/D substations are common across Duke Energy. While most substations typically start with one transformer, many of these substations evolve into two- or three-transformer installations. The development of a P2P-based CPC design for a multiple transformer bank substation, as detailed in this research, provides a realistic study of what a CPC system needs to include to meet performance and reliability requirements of a typical utility T/D substation. The additional control function and features designed into the CPC design are required for any future design and installation. Knowing that the P2P-based CPC design can meet the performance requirements and control functionality for a multiple transformer substation will help clear the path to moving closer to an actual installation.

A key benefit of using a CPC system with redundancy is that of moving away from a protection back-up approach. Legacy approaches of the use of a single transformer differential relay have been successfully used for years, but redundancy offers a significantly higher probability that full protection and control functions are always available, and protection is not compromised by a single device failure.

In addition to significantly reduced panel wiring by the elimination of lockout relays and panel test blocks and switches, the P2P-based CPC system offers the benefits of improved speed of operation for both transformer and bus differential faults. Replacement of overcurrent relays for low-voltage bus protection with a well-defined differential protection option within the CPC system offers the enhancement of a quick trip for bus faults and has the added benefit of faster clearing. This is a welcome bonus obtained from using the newer technologies. Easier troubleshooting is an additional benefit of fewer devices and reduced panel wiring.

Using a P2P-based CPC design facilitates the implementation of a CPC unit. Many of the benefits are not obtained with a hardwired approach for CPC units. Use of MUs not only facilitates a high number of instrument transformer inputs, but significantly reduces the need for large amounts of input/output (I/O) wiring within the relay panels. Design limitations would be dependent on the number of fiber-optic inputs on the CPC units.

An additional benefit of using P2P technology for a CPC system is that there is no need to bring the network hardware and technical skills to the engineering skills, CMP, and training requirements in order to take full advantage of the benefits of a CPC approach. In summary, a P2P approach is simpler and requires less programing demand on the engineering and field personnel than a network-based solution. If a P2P solution is successful, the next logical step is to explore the possibility of additional benefits in a network-based solution.

Proceeding with a P2P-based CPC design requires a wholesale commitment and effort by the utility to ensure success. The initial investment of time and resources would be required to ensure long-term success and repeatability of a CPC design. In addition to keeping all stakeholders engaged in the development of new production standards, their backing will undoubtedly impact the success of the changes required. Changing to a CPC design will require successful implementation of many new innovations such as robust CPC devices and MUs, fiber-optic data transmission (in place of copper), HMI for many operating functions (open and closing breakers, changing settings groups, gathering relay targets, etc.), testing practices (no more test blocks on relay panels), and panel wiring (no more lockouts and excessive copper wiring). Implementing large changes such as these requires a well-thought-out and implemented CMP. Considerable investment will be required to successfully obtain the benefits of a CPC system design.

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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 40 years and a member of IEEE-PES since 1987. He is a registered Professional Engineer in the state of North Carolina and has worked at Duke Power, Duke Engineering and Services, and Duke Energy Corporation since 1987. Mr. Ladd 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.

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Ethan K. Haithcox received his BSEE and MSEE degrees from North Carolina State 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.

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Nathan Urquhart recently graduated from the University of North Carolina at Charlotte. He earned a Bachelor of Science in electrical engineering and is currently working at Digioia Gray – Gannett Fleming as a Protections and Controls Engineer.

Arun Shrestha received his BSEE from the Institute of Engineering, 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. Arun holds six patents and has authored 17 technical papers. His research areas of interest include power system protection and control design, power system modeling and simulation, and digital substations. He is a senior member of IEEE and is a registered Professional Engineer. He is a member of IEEE PSRC 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 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.

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 Engineering Intern in Research and Development and is currently working with the company full time as an Associate Protection Engineer in Government Engineering Services.

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