Distributed Bus Protection Using Process Bus for a Large Transmission Substation at Duke Energy

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Abstract—**This paper presents a case study of bus protection schemes for a large 100 kV Duke Energy transmission substation. The case study compares the existing high-impedance bus differential scheme with a new IEC 61850 process bus-based distributed bus protection design. The study evaluates the two designs in terms of device count, protection unavailability, and bus protection operation speed. The results provide utility-focused insights into the benefits and challenges of applying digital substation technologies for large transmission substations.**

I. INTRODUCTION

Duke Energy is currently evaluating the use of many digital substation technologies. Initially, the use of new technologies is being reviewed as a means to reduce the amount of copper being installed in substations. With many substations large in physical size, with full cable trays/trenches, the installation of new/additional copper wire becomes a challenging and costly proposition. Many of the previous papers written by Duke Energy have focused on the use of point-to-point digital secondary systems (P2P DSS) to reduce the amount of copper compared to the traditional use of copper for connection of current transformers (CTs) and potential transformers (PTs) to protective relays and other intelligent electronic devices (IED) [1] [2]. Both the use of process interface units (PIUs) for P2P technologies or the use of PIUs for an IEC 61850 process bus-based distributed bus protection design, expands the use of fiber-optic cables (already being run to each breaker for annunciation and alarming) within the substation. The PIUs described in this paper includes a merging unit (MU) function for publishing voltage and current as Sampled Values (SV) messages and a switchgear control unit (SCU) function for controlling circuit breakers via GOOSE messages. The P2P approach was viewed as a way to eliminate the need for additional network devices like network switches and clocks that would be required for an IEC 61850 process bus-based protection design. From the previous case studies of P2P DSS, the following benefits are identified for the P2P architecture [1] [2].

- Significant copper reduction
- Expanded use of fiber-optic cables beyond alarming and communications
- Direct connection of PIUs to IEDs
- Minimal changes to existing relay setting templates and designs
- No knowledge or additional skills required for a switched network

While the P2P architecture offers many attractive benefits, a robust change management plan is required for successful implementation. This paper explores the assessment of DSS design that would use an IEC 61850 process bus-based protection design. Some of the potential benefits of a process bus design are similar to the P2P architecture, including copper reduction, and the expansion of fiber-optic cables on the secondary system allowing secondary system monitoring and electrical noise immunity. However, additional potential benefits from using a process bus design exist, including greater flexibility in protection design. It enhances asset visibility through modern self-monitoring diagnostics within the IEDs. While the number of devices and the total volume of settings to be configured increase in a process-bus system, this system offers interoperability, flexibility, and potential lifecycle efficiencies. Additionally, the use of the IEC 61850 standard streamlines engineering, testing, and commissioning by providing a structured data model for substation communications and enables the development of configuration tools. This paper explores the additional hardware and devices, including the required network devices, required to implement the new design. This paper expands on the incremental skills, resources, and training required to implement an IEC 61850 process-bus protection scheme.

Power buses are critical substation elements where multiple network elements such as lines, transformers, and capacitor banks are interconnected. A fault on a bus affects multiple circuits simultaneously and usually results in extremely high fault currents. Without fast and reliable protection, bus faults can jeopardize personnel safety, damage equipment, and adversely impact system stability. Duke Energy's protection philosophy is to apply high-speed bus protection with full redundancy to protect these critical elements.

This paper uses a large 100 kV Duke Energy transmission substation for the case study. The substation uses a double-bus configuration with 20 breakers. Out of 20 breakers, manual disconnect switches allow 16 breakers to be served from either bus. Due to many breakers and the flexibility to manually adjust the bus connections, high-impedance bus differential relays are employed for bus protection in the existing substation. Currently, selector switches are included to allow a single differential zone to encompass both buses, simplifying maintenance and switching tasks. This paper describes the existing bus protection design of the substation, followed by detailed design of distributed bus protection using an IEC 61850 process bus. The new distributed bus protection design requires multiple PIUs, SV bus IEDs, Ethernet switches, and satellite clocks. As current signals are transmitted as SV messages in the process bus, a low-impedance distributed bus is selected for the new design. The paper demonstrates the importance of Parallel Redundancy Protocol (PRP) in a process bus using test results from SV IED and unavailability calculation for the PRP network. Comparative analysis of using IEC 61850-9-2 LE vs IEC 61869-9 SV profile and its impact on process bus network design is included in the paper.

Following the process bus-based bus protection design, the paper compares the two designs analytically by using device count, protection scheme unavailability, and bus protection operation speed as criteria. Compared to the existing design, the process bus-based design requires additional devices due to the addition of PIUs, Ethernet switches, and satellite clocks. Using fault tree analysis, the paper compares bus protection unavailability between two designs. The paper discusses Duke Energy's study efforts in their pursuit of using digital substation technologies. The paper provides Duke Energy's perspective on the IEC 61850-based process bus, its potential advantages, and associated technical challenges. The technical insights derived from this study will aid Duke Energy in the decision-making process concerning the implementation of a process bus for large transmission substations.

II. DUKE ENERGY'S TRANSMISSION SUBSTATION OVERVIEW

The transmission substation used in this study contains 230/100/44 kV autotransformers, 100/44 kV power transformers, and transmission lines at 230 kV, 100 kV, and 44 kV. The scope of this study is focused on the 100 kV bus protection. Fig. 1 illustrates a single-line diagram of the 100 kV buses for this substation. A total of 20 breakers are used on the 100 kV voltage level.

- Four breakers for the two 230/100/44 kV autotransformers (two 100 kV breakers per autotransformer, one tied to each bus)
- Three breakers on 100 kV side of the 100/44 kV power transformers
- One breaker for 100 kV capacitors (two independently switched 100 kV capacitors)
- Twelve breakers for 100 kV transmission lines (six double-circuit lines)

The 100 kV buses in this substation are arranged in a double-bus configuration. In a normal mode of operation, all breakers are closed; half of the 100 kV breakers are connected to one bus (Red Bus) and other half of the breakers are connected to the other (Yellow Bus). The two bus sections are electrically tied together through the two 100 kV breakers used for each autotransformer. The six double-circuit transmission lines are connected such that each of the lines is tied to a different bus. Two of the 100/44 kV power transformers are tied to one bus and the third to the other bus.

Normal setup and operation have 10 of the 20 breakers electrically tied to one bus and 10 tied to the other. The substation is built with switches that allow any breaker to be electrically tied to either bus. Bus protection can be altered to encompass all breakers within a differential zone.

A. *General Protection Philosophy*

Duke Energy's approach to protection requires fast protection within the confines of the substation. Individual protection zones are established for all buses and all major apparatuses, autotransformers, power transformers, capacitors, etc. All new 100 kV and 230 kV substations require full redundancy of protection. Differential protection is implemented to provide fast protection for all buses and all transformers within these substations. Overlap of protective zones is implemented at all substation breakers to ensure all substation faults are detected, including those within the interrupting devices. Fast differential protection is implemented for all buses and all transformers at 100 kV and above.

Operation of the substations requires the maintaining of fast protection for all zones of protection under normal circumstances. No single device failure or blocked protective device will prohibit fast differential protection for bus faults.

B. *Bus Protection Philosophy*

Historically, high-impedance bus differential protection has been used at Duke Energy for many decades. It was always viewed as dependable, providing fast protection for a substation bus. As protection migrated towards microprocessor-based relays (IEDs), the last remaining electromechanical relays were used for bus protection. In more recent years, smaller substations offered the opportunity to use microprocessor-based low-impedance bus differential relays, but large substation size with many breakers limited the use of these devices. With most new Duke Energy substations, the microprocessor-based high-impedance bus differential relay is the relay of choice. Microprocessor-based relays provide many benefits over the electromechanical predecessors including monitoring of the protective device's health.

C. *Bus Protection for New Greenfield Substations*

New 230 kV substation configurations are either a breaker-and-a-half design or a ring bus. Virtually all 100 kV buses in large transmission substations are a double-bus design. Smaller substations have used some low-impedance microprocessor bus differential relays, but generally substations that are large will use high-impedance microprocessor relays. All new construction requires full protection redundancy in the form of two independent protective systems. Each system contains its own relay, CTs, DC sources, and trip coils. These components are not shared between systems so that the removal or failure of one component in one system would not impact the other.

D. *Brownfield Substation Bus Protection Upgrades*

Generally, the same bus protection guidelines are applied during brownfield substation protection upgrades that are used for greenfield installation. In most applications at 230 kV, this can be easily implemented. However, some limitations with existing 100 kV breakers and available CTs often make the installation of completely redundant designs (redundant relays and CTs, DC and trip coils) either difficult or impossible. The most common challenges reside with CT ratio matching. However, when grid threats are identified, dual protection systems are installed.

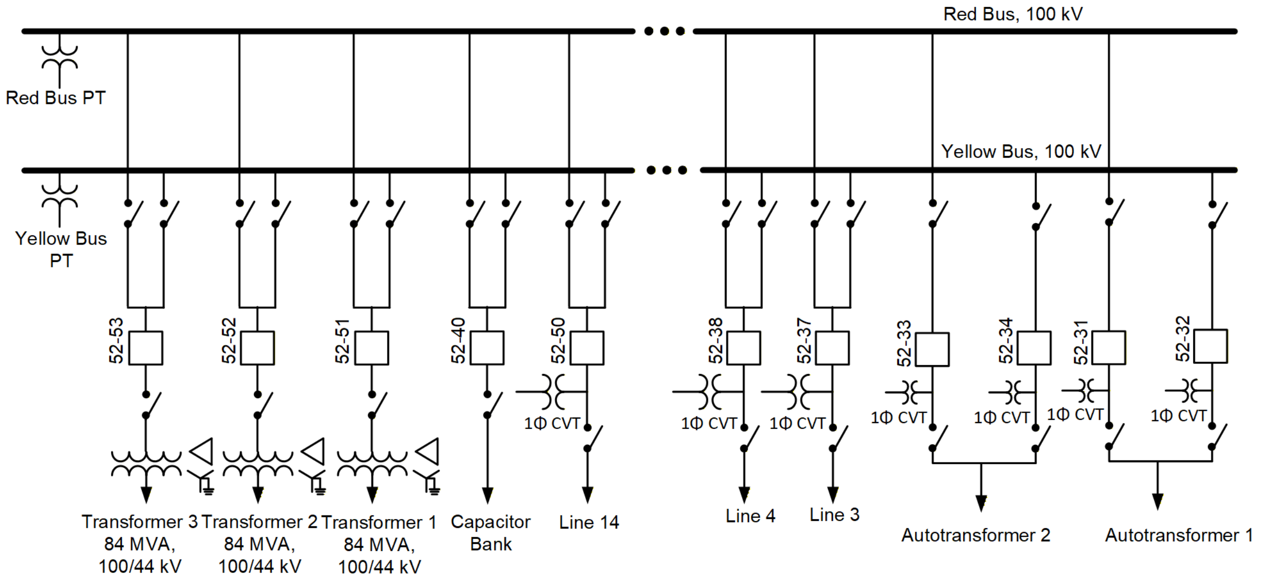

Fig. 1. Single-line diagram of 100 kV section of transmission substation at Duke Energy.

III. DUKE ENERGY'S EXPLORATION OF DSS

The use of DSS for bus protection within the substation offers some potential benefits for the utility. Some of the more commonly stated benefits are:

- Elimination of heavy CT cables run from the relay panels to the breakers
- Elimination of CT handling hazards within the control house. CT handling hazards will still be present at the breakers or at the PIU boxes
- Potential reduction in costs
- Potential for labor savings of installing fiber over cable
- Continuous monitoring of secondary system
- Flexibility in protection design

The potential benefits of copper reduction are obtained with the addition of some different/additional costs in other areas. Additional equipment/devices will be required. Additional engineers and field technicians with new/different skillsets will be required, along with a robust development plan. The following sections list some of these items that will offset the potential benefits of using an IEC 61850 process bus-based protection design. The additional devices and comparisons of the older historical schemes versus a newer IEC 61850 design are detailed further in this paper.

A. Additional Equipment for IEC 61850 Ethernet-Based Solution

- PIUs
- Network Switches
- More fiber-optic cables
- Landing fibers—Patch panels/Splice boxes for fiber-optic cables
- PIU enclosures
- Larger battery and charger

B. Additional Resources With Ethernet-Based Solutions

- More devices to program
  - PIUs
  - Network Switches
- Additional field resources and skill sets
  - Installation, testing, troubleshooting, programming/configuration, etc.
  - Field testing and commissioning changes. Change management issues
- Additional engineering resources and skill sets
  - New skill sets for Network Devices and Programming
  - Databases for network devices
  - New engineering drawings for fiber optics
  - Engineering compliance related activities
- Cybersecurity and compliance challenges—All Ethernet-based designs like IEC 61850 bring new challenges of having Ethernet protocols both inside and outside of control house.
  - Additional security requirements for devices in yard

C. Additional Items Identified for Success

- Dedicated lab for testing
- Dedicated resources to develop repeatable standards and lab test
- Completion of change management plans [1]

IV. BUS PROTECTION DESIGN

In this section, bus protection design for the transmission substation under study is discussed. The existing substation uses electromechanical high-impedance bus IEDs for protecting both Red and Yellow Buses. The secondary system and its associated protection and control devices for the existing bus protection are presented first. Next, process bus-based distributed bus protection design for the same substation is described. In the new design, Duke Energy's requirement of full redundancy is maintained. Copper wires from the CTs and circuit breakers are replaced with PIUs, network switches, and fiber-optic cables in the new design.

A. Existing Bus Protection Design

As discussed in Section II, the transmission substation consists of two 100 kV buses (Red Bus and Yellow Bus) and 20 breakers. During normal operation, 10 breakers are connected to the Red Bus and the remaining 10 breakers to the Yellow Bus. All breakers run normally closed. Autotransformer 1 and Autotransformer 2 are connected to both buses (refer to Fig. 1). The rest of the network elements can be connected to either bus by using two manual disconnects associated with each breaker. This design allows all network elements to be connected to one bus when the second bus needs maintenance.

Each breaker houses four CTs, two bushing CTs on the line side and two bushing CTs on the bus side. The current sources for bus protection are the bushing CTs on the line side of each breaker. Redundant bus protection is applied with two sets of bus differential IEDs. Primary and secondary bus protection uses two separate bushing CTs. Fig. 2 shows the secondary connection and IEDs for the primary bus protection of both buses. Due to the large number of breakers and the ability to manually configure the bus connections, high-impedance bus differential protection is used. For primary protection, the first set of the line-side CTs are utilized, labeled "P" in Fig. 2. Electromechanical (EM) high-impedance bus differential relays are installed to provide bus protection on a per-phase basis. For each phase, the currents from all ten breakers are physically summed and connected to the corresponding high-impedance differential IED. Phase A currents are summed up and applied to the Phase A bus differential IED, with identical implementation for Phase B and Phase C, as illustrated in Fig. 2. Additionally, current selector switches are included to form a single bus differential zone to cover both buses during bus maintenance. This switch effectively allows the Yellow Bus and Red Bus to become one large, protected differential zone. For an internal bus fault, the bus IEDs energize dedicated master trip relays (ANSI: 94), which then trip all breakers associated with the bus zone. A similar scheme is used for the substation's secondary bus protection, with the second set of breaker bushing CTs (labeled "S" in Fig. 2) and second set of EM high-impedance bus differential relays. The existing bus protection design uses twelve high-impedance bus differential IEDs, two current selector switches, and four master trip relays.

High-impedance bus differential protection is typically chosen when simplicity and scalability are prioritized. High-impedance differential schemes function by placing a very high-impedance across the paralleled CTs of the protected zone; any differential current forces a measurable voltage across the IEDs internal impedance. Because the relay only sees one current due to the parallel CTs, there is effectively no limit to how many lines a high-impedance differential scheme may protect. CTs in a high-impedance differential scheme must share the same CT ratio and perform similarly under all conditions, or risk misoperation [3]. Furthermore, in protected zones with large amounts of incoming and outgoing connections, costs may become considerable due to the additional copper and labor needed to make the necessary secondary connections.

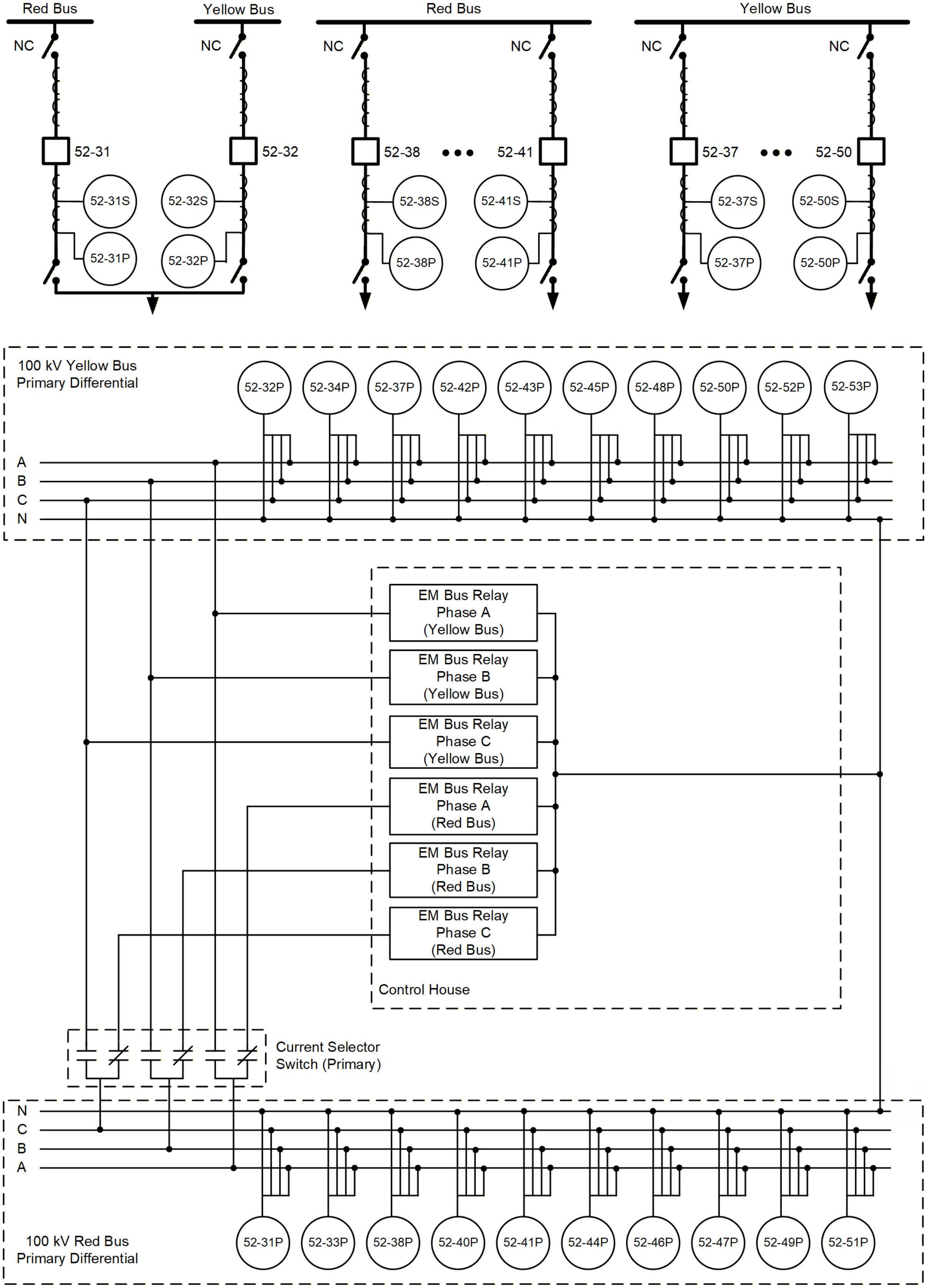

Fig. 2. Existing bus protection design for primary Red and Yellow Bus.

B. Process Bus-Based Bus Protection Design

In an IEC 61850 process bus-based substation, PIUs digitize voltage, current, and switchgear status information and transmit the data to the IEDs for protection and control applications. Reliable operation of the process bus requires network switches and dedicated external time sources. Typically, all IEDs and PIUs are time-synchronized using network-based Precision Time Protocol (PTP). The external time source enables PIUs to accurately time stamp SV messages. IEDs time-align SV messages received from multiple PIUs by compensating for sampling time variations and network-induced delays prior to using the messages in P&C functions. Loss of the external time source can affect SV time alignment and may impact the operation of protection and control functions. For this reason, incorporating redundancy in external time sources is a recommended practice for process-bus architectures.

The SV bus IED used in this study supports high-speed, low-impedance bus differential elements. Each IED provides six protection zones and three check zones. One IED can protect as many as seven terminals in three-phase mode, and as many as twenty-one terminals when one IED is used per phase. Because the IED receives currents as SV messages, it does not rely on fixed CT wiring. Bus zone assignments are created in logic, and the IED can update them automatically during switching operations. The IED can also compensate for CT ratio differences and CT saturation, which is important when different CTs from multiple merging units are used in the same system. Low-impedance bus differential protection algorithm is implemented in the SV bus IED, which provides both security and fault detection. Additional functions, such as check-zone logic, directional and voltage supervision, breaker-failure elements, and fault-detection logic, improve reliability [4] [5]. These features make low-impedance bus protection better suited for modern bus bar applications.

Fig. 3 shows process bus-based bus protection design for the transmission substation under study. Three SV bus IEDs are used for the Red and Yellow Bus primary protection, with one IED assigned to each phase. Each bus IED receives current information from all twenty CTs via SV. The primary protection system uses twenty-two PIUs. Twenty PIUs measure currents from breaker CTs and a single-phase voltage from CVT, and two PIUs measure three-phase voltages for both buses. Each PIU has two sets of three-phase CT inputs. One set is used for bus protection, and the other set is used for bay protection, such as line or transformer protection. Because of this design, each PIU publishes two SV streams. One stream is sent to the bus IED, and the other is sent to the bay protection IED. Breaker and disconnector status inputs are wired to the PIUs. These positions are transmitted to the IEDs via GOOSE messages. Trip commands from the IEDs are also sent to the PIUs via GOOSE, and the PIU output contacts are wired to the breaker trip coils.

The communication network that carries SV, GOOSE, and PTP messages is shown in Fig. 3. Two independent clocks provide time synchronization signals to PIUs and IEDs by using PTP [6] [7]. All PIUs, IEDs, and clocks publish their data on two Ethernet LANs, shown as solid blue lines for LAN A and dashed red lines for LAN B. These two networks operate based on PRP, so all the devices continue to send and receive data even if one communication path fails [8]. The Ethernet switches in the control house forward all SV, GOOSE, and PTP messages to the three busbar IEDs. Similarly GOOSE messages from the IEDs and the PTP messages from the clocks are also delivered to each PIU through both LANs. This PRP arrangement removes single-point failures and ensures continuous data availability across the entire process-bus network [6].

In the SV bus IED, all ten current signals from Red Bus are assigned to Bus Zone 1 and the remaining ten current signals from Yellow Bus are assigned to Bus Zone 2. During normal operation, Bus Zone 1 and Bus Zone 2 operate independent of each other and provide bus protection to Red Bus and Yellow Bus respectively. When one of the buses needs maintenance, all network elements are connected to another bus. During maintenance period, Bus Zone 1 and Bus Zone 2 are connected internally via logic in the SV bus IED to form a combined Bus Zone 1 and 2. No current selector switches are required, and no CT circuits need to be changed or switched with this design. All zone selection is performed in logic, which keeps wiring simple and improves response time. Because one SV bus IED can protect both single-phase bus zones, the design needs only one IED per phase. This results in three SV bus IEDs in total for all three phases. In contrast, the existing high-impedance design requires a full per-phase set for each bus, resulting in six IEDs for two buses. The low-impedance, process-bus approach eliminates this duplication. One set of three IEDs supervises both zones and all twenty terminals, reducing the number of IEDs from six to three while maintaining full busbar protection functionality.

The process bus-based bus protection design for the secondary Red and Yellow Bus is similar to that of primary bus protection design. The secondary system also has twenty-two PIUs, three SV bus IEDs and uses the time synchronization from the additional ports of two clocks from the primary system. The PIUs use second set of CTs on both sides of the breakers for the secondary system. Hence, the primary and secondary bus protection designs are completely independent of each other.

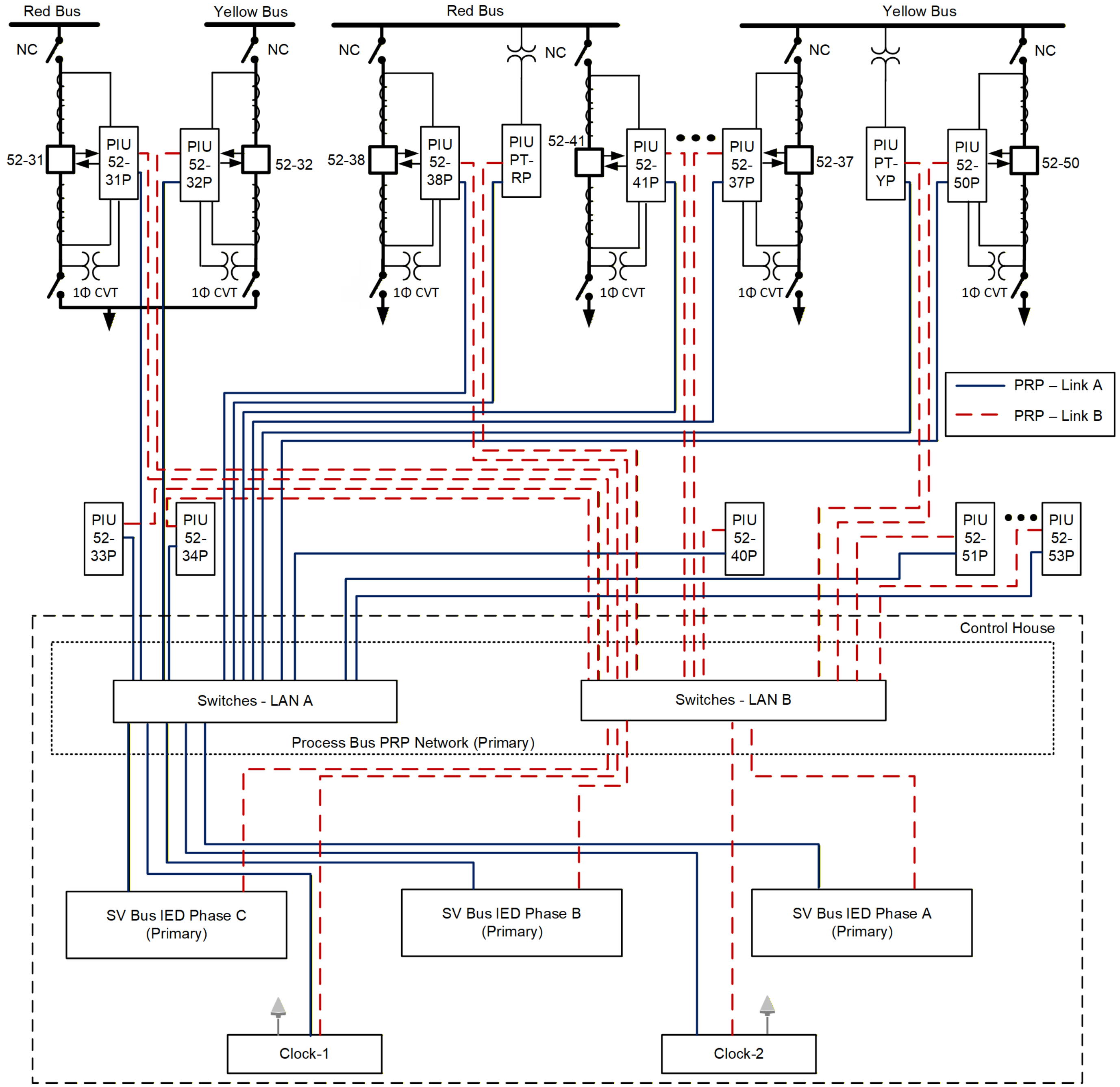

Fig. 3. Process bus-based bus protection design for primary Red and Yellow Buses.

1) Importance of PRP in Process Bus Applications

In an IEC 61850 process bus, SV and GOOSE messages published by PIUs traverse through fiber-optic cables and Ethernet switches before they are subscribed by IEDs. If a fiber-optic link breaks or there is any issue with the Ethernet switch, SV and GOOSE messages are unavailable to IEDs. Loss of these critical messages can result in unavailability of protection and control functions. Hence, PRP is highly recommended in process bus applications. In a PRP process bus network, PIUs and IEDs transmit identical Ethernet frames simultaneously over two independent networks, LAN A and LAN B. The receiving device processes the first frame received and discards the duplicates. PRP provides seamless recovery from an Ethernet switch failure and fiber-optic cable damage. As a result, there is no single point of failure in the communication network and protection functions remain operational during network issues.

Fig. 4 shows an operation of an SV Line IED during a fault and the simultaneous link failure on a PRP LAN A network. The test was conducted in a lab with an SV Line IED receiving SV and GOOSE messages from multiple PIUs in a PRP network. During the test, the test set injects fault signals to the PIUs and sends a control signal to a link breaker to interrupt a fiber-optic cable in PRP LAN A associated with a PIU. The top and middle plot shows the current and voltage samples received by the SV Line IED. The bottom plot shows that PRP LAN A link failed during three-phase fault time interval while PRP LAN B remained available. The SV Line IED continues to receive SV messages through PRP LAN B during this event. As a result, its protection elements remained available, and it issued trip command for the three-phase fault. This test demonstrates the importance of PRP in a process bus. As more utilities start to deploy process bus applications in transmission substations, it is critical that they implement PRP for seamless and zero-recovery-time redundancy.

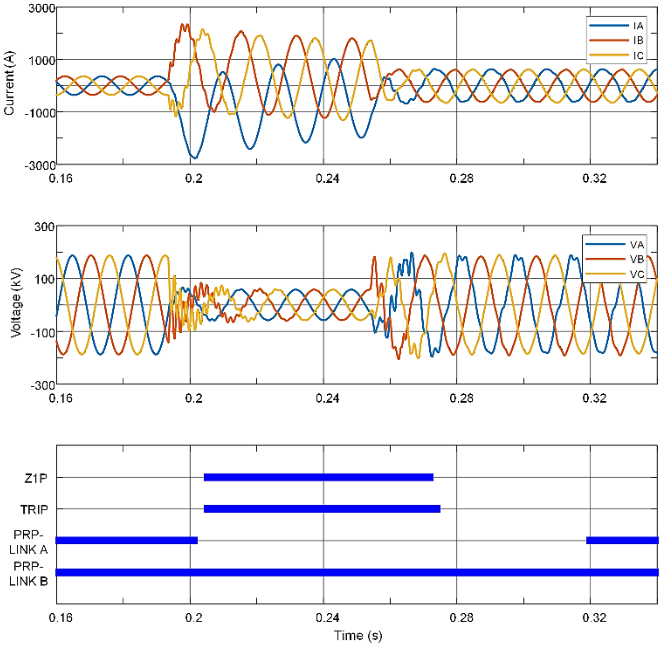

Fig. 4. Protection function remains operational during LAN A link failure in a PRP network.

2) *IEC 61850-9-2 LE and IEC 61869-9 SV Profiles*

To implement process bus-based bus protection, multiple SV profiles are available in PIUs and SV bus IEDs. Initial adoption of SV was accelerated by the publication of IEC 61850-9-2 LE guidelines in 2004 [9]. The IEC 61850-9-2 LE SV profile uses a fixed data set of four currents and four voltages. Similarly, the sampling rate is also fixed at 80 samples per cycle. In contrast, IEC 61869-9 is a fully standardized SV profile that supports configurable datasets and multiple sampling rates [10]. The flexibility in IEC 61869-9 SV profile has direct impact on the SV payload and the network bandwidth requirements.

As discussed earlier, each PIU measures two three-phase currents from two CTs, one from the bus side and another from the line side. For simplicity, we are not considering single-phase CVT signal connected at the line for this analysis. The line-side CTs are used for bus protection and the bus side CTs are used for line, transformer, and capacitor bank protection. For primary protection, 20 PIUs at required and each PIU needs to publish two SV streams. There is a total of 40 SV streams for currents for primary protection. Each three-phase CT signals can be published using IEC 61850-9-2 LE or IEC 61869-9 SV profile. When IEC 61850-9-2 LE SV profile is used, unused analog channels (fourth current channel and all four voltage channels) are populated with zero. For IEC 61869-9 SV profile, we can include three current channels in its data set. Moreover, it supports multiple Application Service Data Unit (ASDU) structure, allowing one or multiple sampled measurements in one SV message.

Table I shows the SV bandwidth for IEC 61850-9-2 LE and IEC 61869-9 SV profiles [9] [10]. Further, IEC 61869-9 SV profile with one and two ASDUs are listed. The fourth column shows the total network bandwidth for 40 SV streams, and the fifth column lists the reduction in network bandwidth with respect to IEC 61850-9-2 LE profile. When IEC 61869-9 2 ASDU SV profile is used, the bandwidth requirement reduces by 42.5 percent. Whenever available, preference shall be given to IEC 61869-9 SV profile, as it optimizes network switch usage. With this profile, same network infrastructure can carry far more SV streams than with IEC 61850-9-2 LE profile.

V. COMPARISON BETWEEN EXISTING AND PROCESS BUS-BASED BUS PROTECTION DESIGN

This section analytically compares two bus protection designs by using device count, protection scheme unavailability, and bus protection operation speed as criteria. The analysis highlights the advantages and challenges associated with adopting a process bus-based bus protection design for a large transmission substation.

TABLE I
SAMPLED VALUES BANDWIDTH FOR DIFFERENT PROFILES AT 60 HZ

SV Profile	ASDU	Bandwidth Per Stream (Mbps)	Bandwidth for 40 Streams (Mbps)	Reduction in Bandwidth (%)
IEC 61850-9-2 LE (4I4V)	1	5.376	215.040	--
IEC 61869-9 (3I)	1	4.147	165.888	22.9%
IEC 61869-9 (3I)	2	3.092	123.648	42.5%

A. Device Count

Table II lists various devices and secondary systems used for bus protection in the existing substation. A total of 12 high-impedance bus differential IEDs are used, six for primary protection and the remaining six for secondary protection of both Red Bus and Yellow Bus. The high-impedance bus relays send trip signals to the master trip relays, which then trips the breakers in the faulted bus zone. Copper cables connect line-side CTs to the high-impedance bus IEDs and connection between breakers and IEDs for control. The total copper cable length of 42,380 ft is calculated for overall bus protection by using 4c12 cable type for CTs and 3c8:9c12 cable type for control.

TABLE II
DEVICES USED IN THE EXISTING SUBSTATION BUS PROTECTION

Description	Units
EM bus relay	12
Master trip relay (94)	4
Current selector switch	2
Test switch	8
Copper cables	42,380 feet

A tabulated list of devices used in the process bus-based bus protection design is shown in Table III. Due to the capability of the SV bus IED to protect two bus zones, total number of bus IEDs decreased to six. However, the process bus-based design requires large number of PIUs, Ethernet switches, and satellite clocks. Addition of these devices helps to monitor the secondary system between PIUs and bus IEDs. The new design eliminates the need for current selector switches and master trip relays. Note that SV streams from same PIUs are used for lines, transformers, and capacitor bank protection. A total fiber-optic cable length of 33,104 ft is calculated by assuming a cable with two fibers. Adding 40 PIUs, 8 Ethernet switches, and 2 satellite clocks will require the station dc power system capacity to double. Eight Ethernet switches are selected, with four dedicated to the primary system and next four to the secondary system. The primary system uses two switches, each for LAN A and LAN B, and with 24 ports per switch, this configuration supports all device connections while providing sufficient spare capacity.

TABLE III
DEVICES USED IN PROCESS BUS-BASED PROTECTION

Description	Units
SV bus IED	6
Process Interface Unit (PIU)	40
Ethernet switch	8
Satellite clock	2
Fiber-optic cables	33,104 feet

B. Protection Scheme Unavailability

Fault tree analysis is widely used by protection engineers to compare the reliability of different protection schemes. This technique quantifies the protection scheme reliability using the laws of probability theory. A fault tree comprises a top event representing the failure of interest and a set of basic events that contribute to the top event through logic gates. The outcome of the fault tree analysis is the overall unavailability, which is the fraction of time when the identified failure occurs, and the system is unable to perform its intended function. Higher unavailability results in lower system reliability. Each basic event has an unavailability value, which is unitless, that can be calculated using (1).

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

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}).

Using fault tree, unavailability for bus protection for both designs are calculated in this subsection. Table IV summarizes the mean time between failures (MTBF) and unavailability values for each component used in the fault tree. This paper uses the average downtime per failure of two days to calculate unavailability from the MTBF value. Human failures are assumed to be 100 times less likely than hardware failures and require one year for detection and repair. Hence, unavailability for IED misapplication is calculated by multiplying the hardware MTBF by 100 and taking an inverse [11].

The existing substation uses EM high-impedance bus differential relay, whose MTBF value is unknown. EM relays have a simpler design compared to microprocessor-based IEDs. This can result in a higher MTBF value for EM relays. However, these EM relays usually do not have any self-test alarms. If there is a failure in an EM relay, it could remain undetected until the protection scheme goes through its scheduled maintenance (which may take years). EM relays can have higher MTBF and much higher downtime per failure. In the absence of these data for EM bus relay, the unavailability values for existing EM bus relay, SV PIU, and SV bus IED are assumed to be equal for simplicity. If the reader has these values, they can plug them in the fault tree and compute overall unavailability for their bus protection.

TABLE IV
UNAVAILABILITY FOR EACH COMPONENT

Component	MTBF (Years)	Unavailability (10^{-6})
SV PIU and SV bus IED	600	9.13
EM bus relay	NA	9.13
Ethernet switch	300	18.26
Satellite clock	1,000	5.48
IED misapplication	NA	$(MTBF \cdot 100)^{-1} \cdot 1$ Year
Fiber-optic cable	5,000	1.10
Copper wiring	10,000	0.54
Circuit breaker	NA	300
DC power system	NA	50
Current transformer (per phase)	NA	10

1) Fault Tree Analysis for Bus Protection

In the existing substation, ten breakers are connected to the Red Bus during normal condition. For each bus, redundant bus protection (primary and secondary) systems are available. To evaluate and compare bus protection unavailabilities of each design, we consider a top event—bus protection fails to clear in-section fault in the prescribed time. The fault tree for the existing Red Bus protection is shown in Fig. 5. Using the bus protection design from Section IV Subsection A, the fault tree is constructed for the existing Red Bus protection. Due to redundant CTs and bus IEDs, their impact on overall unavailability is minimum. The overall unavailability value of the bus protection is primarily due to breakers and the dc power system.

Next, we developed a fault tree for process bus-based bus protection by using the design from Section IV Subsection B. For Red Bus primary protection, the design uses ten PIUs and three SV bus IEDs. Process bus design uses PRP where each PIU, SV bus IED, and satellite clock connects to both LAN A and B Ethernet switches. Top portion of Fig. 6 shows the fault tree and unavailability value for the combined Ethernet switch and clock failure for primary protection. Application of PRP network and redundant satellite clock has significantly lowered their overall unavailability value to 0.0042.

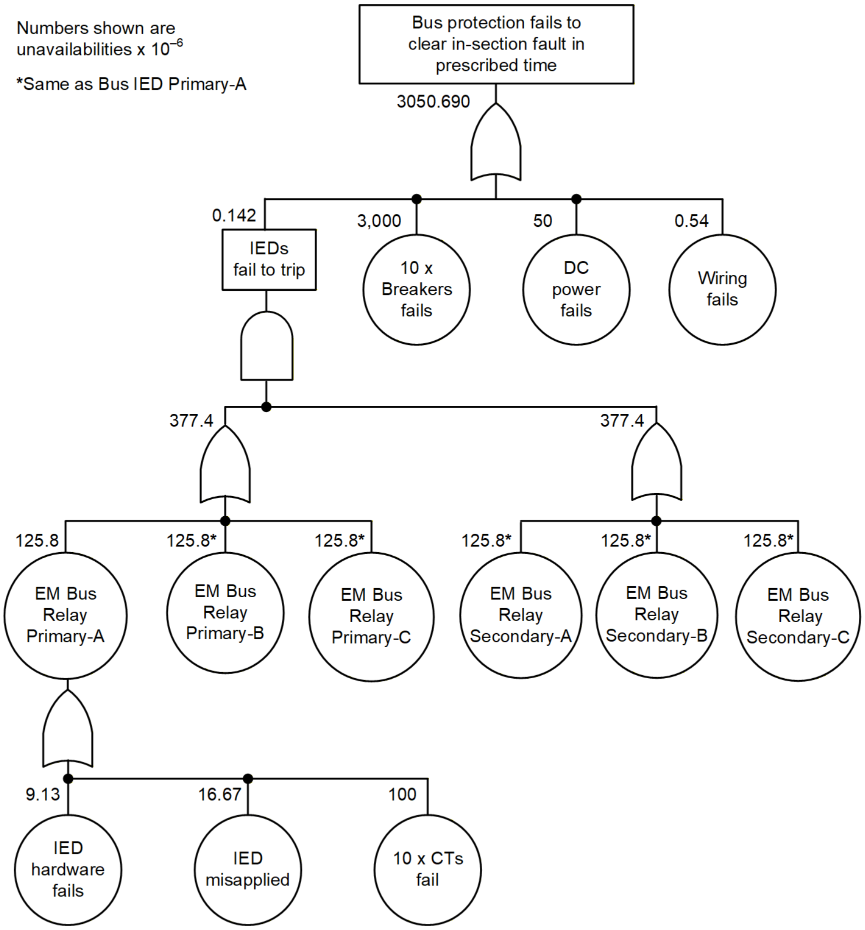

Fig. 5 Fault tree for Red Bus protection in the existing substation.

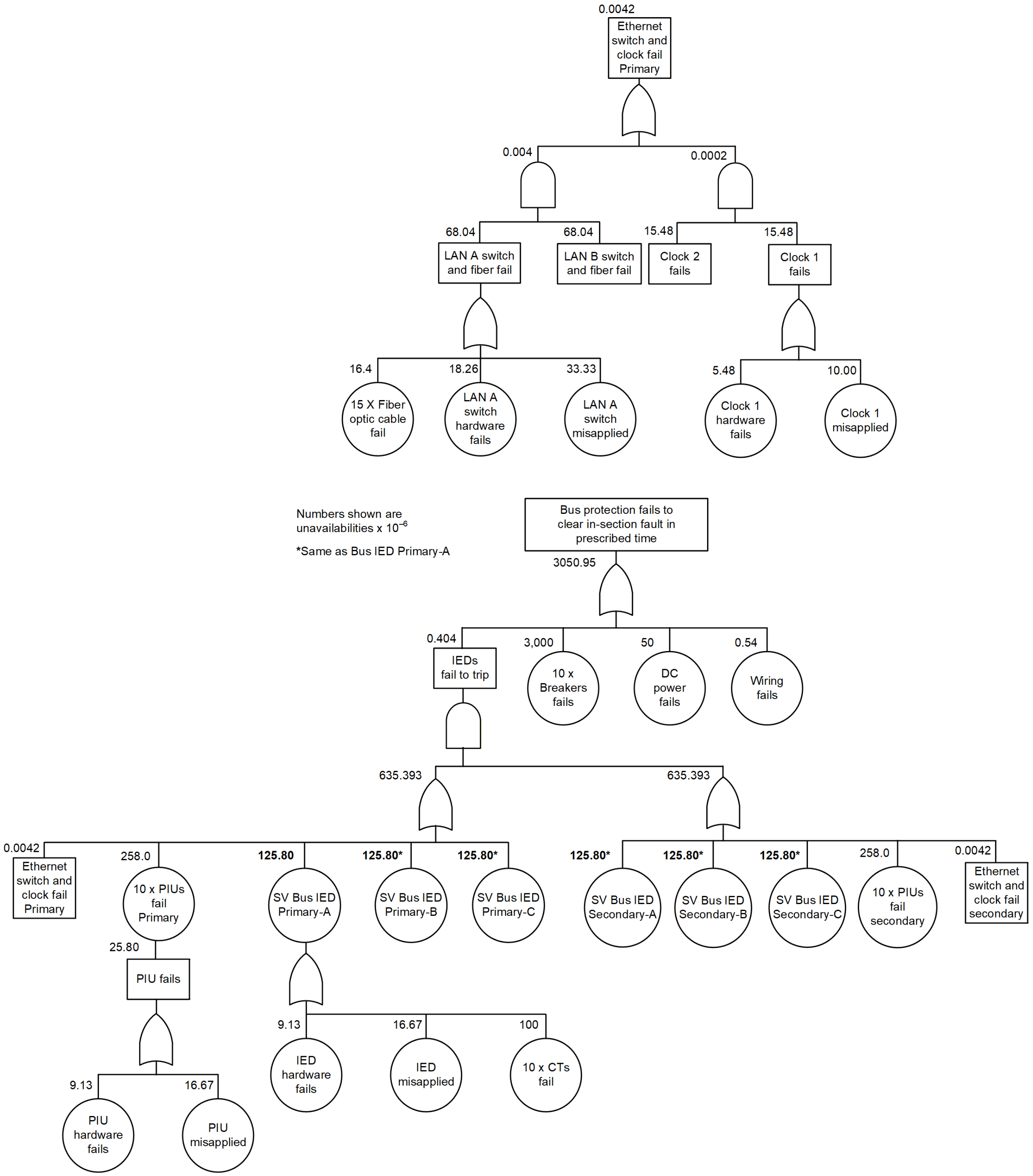

Fig. 6 Fault tree for Red Bus protection in the process bus-based design.

Fig. 6 shows the rest of the fault tree and the final unavailability value for Red Bus protection. Redundant CTs, PIUs, SV bus IEDs, clocks, and PRP network has significantly lowered their combined unavailability value to 0.404.

Table V shows the unavailabilities for bus IEDs and overall bus protection. Although the unavailability of bus IEDs for process bus-based design is 2.85 times higher than that of the existing system, the overall bus protection unavailability is comparable between designs. It is because the overall unavailability is dominated by breaker and dc power system. System unavailability can be reduced by using high-quality components with higher MTBF values, simpler system designs, or adding redundancy. While redundancy enhances dependability, it may reduce security and increase system complexity and cost [12].

TABLE V
BUS PROTECTION UNAVAILABILITY (10^{-6})

Solution	Bus IEDs	Overall Bus Protection
Existing system	0.142	3050.690
Process bus-based system	0.404	3050.950

C. Bus Protection Operation Speed

Power buses serve as a common connection point for multiple network elements. A fault on the bus requires that all network elements contributing fault current be disconnected to isolate the fault. As modern power systems are increasingly operated near their stability limits, high-speed bus protection is essential. Fast bus protection operation speed results in faster fault clearing time. Fast fault clearing improves personnel safety, reduces equipment stress and damage, and enhances overall power quality.

Fig. 7 shows the test setup used to measure bus protection operation speed. The existing bus protection uses EM high-impedance bus IEDs. These IEDs are quite old and were not available for testing. Instead, a traditional microprocessor-based low-impedance bus IED was used to replace the existing high-impedance bus IED for the test. The SV bus IED is identical to the traditional microprocessor-based bus IED except for the fact that it receives analog and binary signals via SV and GOOSE messages. The SV bus IED also includes high-speed output contacts that can be used for tripping. The current outputs from the test set is wired to the traditional bus IED and then daisy-chained to four PIUs. Since the test set has limited current channels, some current channels were daisy-chained multiple times in the traditional bus IED and PIUs to match the bus configuration of the existing substation. The high-speed output contacts from the traditional bus IED, SV Bus IED and all four PIUs are wired back to the test set to monitor trip signals. Four PIUs, SV bus IED, and two satellite clocks are connected to two Ethernet switches to form a PRP network. The SV bus IED receives current signals as SV messages from all PIUs and then sends trip signals back to PIU as GOOSE messages. Both bus IEDs are configured with the same protection settings to protect a single-phase bus.

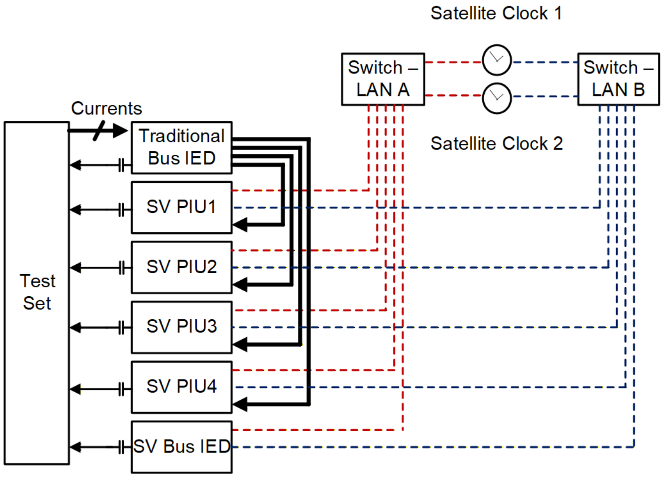

Fig. 7 Test setup to compare bus protection operation speed between traditional and SV Bus IEDs.

To compare the operation speed of both bus IEDs, an internal bus fault is applied and the IEDs response is recorded. Fig. 8 shows the time-aligned event reports from both bus IEDs following the fault. The top plot shows the current waveform recorded by the traditional bus IED during the test. The bottom plot shows the trip signal from both bus IEDs. As evident from the bottom plot, traditional bus IED operates faster than the SV bus IED. The SV bus IED receives SV messages from four PIUs, time-aligns those messages and uses the signal for bus protection. To account for PIU sampling time variation and network delay associated with SV message transmission, SV IEDs have a user-configuration time setting to handle these variations. In the SV bus IED, it is set to the default value of 1.5 milliseconds. As a result, operation of SV bus IED is delayed around the setting value. PIUs on the other hand receives bus protection operate signal from the SV bus IED as GOOSE message and then converts this message into its own trip signal. Hence, the operation of PIUs is further delayed by factors like SV bus IED GOOSE publication, network latency, GOOSE reception and processing time in PIUs, and operating time of PIU output contact used.

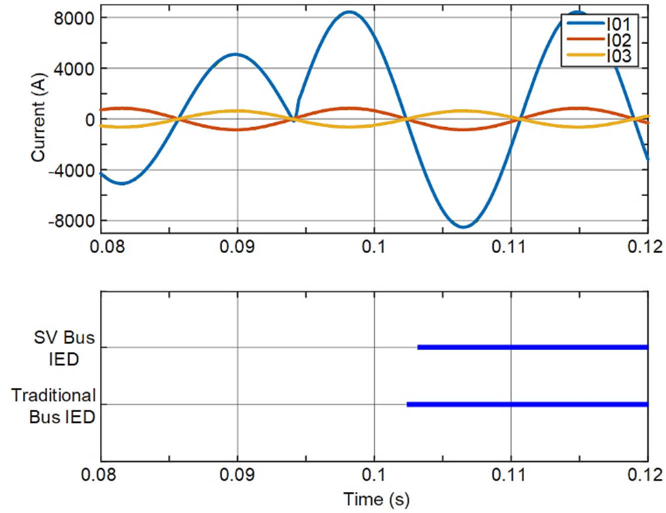

Fig. 8 Bus protection operation time between traditional and SV Bus IEDs.

Round-trip time is the interval between fault inception and receipt of the trip signal. To compare the round-trip time of a bus protection element, a fault is repeated 20 times using the test setup described earlier. The round-trip times measured by the test set for traditional bus IED and SV bus IEDs are illustrated in Fig. 9. Each blue dot represents a test point, with the red dot being the average operation time. The variations in the round-trip times are primarily due to the data acquisition and processing pipeline of the IEDs.

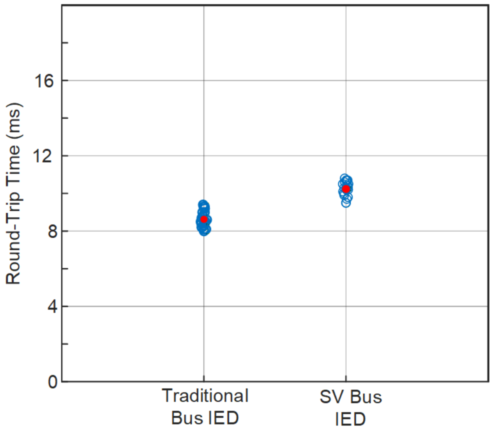

Fig. 9 Round-trip time for traditional bus IED and SV bus IED.

The average round-trip times for bus protection are tabulated in Table VI. The average round-trip time is lower for the traditional bus IED than for the SV bus IED. Similar tests results for other protection elements for traditional and SV-based IEDs can be found in [13] [14]. The difference between the maximum and minimum round-trip time for each IED is around 2 ms, which corresponds to the processing speed of the IEDs.

TABLE VI
AVERAGE ROUND-TRIP TIME AND DIFFERENCE WITH RESPECT TO TRADITIONAL BUS IED

Solution	**Bus Protection**	
	Trip Time (ms)	**Difference (ms)**
Traditional Bus IED	8.625	NA
SV Bus IED	10.235	1.61

VI. LESSONS LEARNED AND FUTURE PLANS

There were several lessons learned from this case study on process bus-based bus protection. First is the stated goal and benefit of copper wiring reduction and reduction in wiring complexity, both in the yard and in the control enclosure. This is frequently stated as the primary goal of digitizing substation protection, and the benefit is real and removes potential safety issues with energized CT cables from the control enclosure. The process bus-based design, like the P2P design, allows for monitoring of the secondary systems and allows for quick alarming in the event of protection equipment failure from the CT to the IEDs. In addition, the reliability and speed of protection are equivalent to both the older electromechanical design, as well as the newer bus protection designs Duke Energy employs with IEDs as the bus protection relays, so there is no loss to the protective capabilities of the process bus-based design. The flexibility of process bus-based design is also a great benefit. The ability to program bus differential protection for all associated breakers in one set of bus protection IEDs allows for a great degree of granularity in the bus arrangements and the associated protection, far greater than what is currently in use with the CT switches. Being able to control through the relays' logic which breakers are used in which differential scheme provides a benefit to the operations personnel and the field technicians.

There are some challenges associated with the process bus design. First, the total number of devices in the protection scheme increases when compared to both the older electromechanical devices and the newer IED-based designs. The number of devices that require settings from engineering increases by 4 to 14 times, depending on whether an electromechanical or IED design is being replaced. The increase in dc-powered devices would necessarily increase the size of the battery and the dc system in general. In some of the larger stations at Duke Energy, battery size is already becoming a design challenge due to the footprint of the required batteries. Increasing the battery size due to the increase in dc-powered devices would add strain on top of this. This is of particular concern as Duke Energy wished to look at the bus protection using process bus specifically in larger stations where manufacturer proprietary point-to-point digital protection struggle with the number of breakers involved. The increase in the number of programmable devices, while reducing the complexity of wiring and construction, increases the complexity and engineering effort for the settings engineer and the field technician responsible for commissioning those settings. The PIUs, the switches, and the clocks all need to be programmed and commissioned in addition to the protective relays. Programming and commissioning these devices requires new skill sets for the typical protection engineer and field technician, and comprehensive training must be provided. The customization of switch programming also poses a potential challenge for the settings engineer. Standards settings templates at Duke Energy currently have a protective relay preset to handle any configuration that relay may need to be placed in. During the application, the different configurations may be turned on and off in the template with very minimal programming from the production engineer. This allows for quick turnaround, a small number of maintained settings templates, and a reduction in human error. To achieve the same level of standardization that Duke has historically had, protection engineers and network engineers would need to work together to create all new workflows and processes.

Duke Energy is interested in applying digital substation technologies. However, the challenges that currently exist for fully applying a process bus-based design in large substations means that Duke Energy will probably wait on applying a full process bus-based design. We will continue to gain familiarity with digital substation technology using the proprietary P2P technology available in smaller substations initially. At the same time, Duke Energy will continue learning about and evaluating process bus technology. Considerable engineering and network resources will be required to develop repeatable and standardized modular designs before this technology will be used. The initial steps require extensive lab testing and development before moving forward.

VII. CONCLUSION

Duke Energy's plans to explore digital substation technology prompted us to do a case study with SEL on a theoretical application of a full process bus protection design for a bus protection scheme at a large transmission substation with voltages at 44 kV, 100 kV, and 230 kV. The process bus design would perform comparably in speed and reliability to the existing electromechanical based bus protection design and the newer microprocessor-based bus protection design. The process bus-based design also provides much greater flexibility in application and operation of the bus protection scheme while reducing the number of copper cables and the wiring complexity both in the control enclosure and out in the substation yard. The process bus-based design at a larger substation does cause a large increase in the total number of devices and thus puts a much larger load on the dc system. In addition, the reduction in wiring complexity is accompanied by an increase in settings complexity. Due to the additional requirements associated with the full process bus system, Duke currently plans to continue with implementation of proprietary P2P digital substation technology. Process bus technology advancements will continue to be studied, and if Duke Energy's settings requirements are met, process bus may be implemented in the future.

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IX. 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 & Services, and Duke Energy Corporation since 1987. Mr. Ladd has held engineering positions in Substation Apparatus, Protection & Control, and Asset Management. He is currently a Principal Engineer in the Transmission System Standards group.

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Md Aamir Rahmani holds a Diploma in electrical engineering from Jamia Millia Islamia in 2008, India, BS in electronics and instrumentation engineering from Galgotias College in 2011, India, and MS and PhD in electrical engineering from Michigan Technological University in 2021 and 2024, respectively. He joined SEL in May 2024 where he is a Lead Integration and Automation Engineer with Protection systems department in R&D. Aamir began his career in the power industry as a Project Engineer with Schneider Electric in 2011, where he specialized in Substation Automation Systems and has since gained 14 years of experience in various roles across industry and academia. He is a member of IEEE, and IEEE PSRC, and has authored 3 technical papers.

Mauricio Gadelha da Silveira is an electrical engineer who earned his Bachelor of Science degree from São Paulo State University in 2013. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2014 and has since held roles in engineering services, sales and customer services, and research and development (R&D). He is currently a Senior Engineer in R&D. His work focuses on the development of protective relay protocols and communications, network design for critical infrastructure, power system modeling, and cybersecurity assessment. He is a U.S. TAG member of IEC TC 57 WG 10 and IEC TC 38 WG 37.

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