

Practical Experience in Designing and Transitioning to Digital Secondary Systems: AEP's Story and Roadmap

Daniel Musci, Jason Byerly, and Manish Thakur
American Electric Power

Andrew Dulmage, Bryan Seyfert, Chris Burger, and Syed Aarsal Hussain
Schweitzer Engineering Laboratories, Inc.

Revised edition released October 2026

Originally presented at the
53rd Annual Western Protective Relay Conference, October 2026

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Daniel Musci, Jason Byerly, and Manish Thakur, *American Electric Power*

Andrew Dulmage, Bryan Seyfert, Chris Burger, and Syed Aarsal Hussain, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Transitioning to a digital secondary system (DSS) in a substation represents a major shift from conventional protection and control (P&C) design, testing, and maintenance. This paper discusses new considerations utilities must address when adopting DSS technology.

American Electric Power (AEP) began its official DSS transition in 2025 after making the strategic decision to fully implement DSS across the system—from 12 kV distribution stations to 138 kV transmission stations. The successful completion of multiple in-service projects in 2025 and 2026 demonstrates the ability of the utility to modernize design standards, testing procedures, and commissioning processes to support digital architectures. As deployment continues, the utility expects DSS designs to evolve and become more streamlined and efficient. Continued advances in test strategies; improved human-machine interfaces (HMIs) for field services, testing, and commissioning; stronger manufacturer integration; and modernized maintenance practices are anticipated to deliver faster, more flexible, more affordable, and more reliable outcomes for the organization and the end users.

This paper outlines the DSS transition of the utility through a high-level roadmap, detailing how design, testing, and maintenance practices differ between digital and traditional substations. It also examines key challenges that emerge after committing to DSS adoption. Finally, the paper highlights the long-term vision of the utility for DSS, with a particular emphasis on consolidating P&C functionality to achieve greater reliability, operational simplicity, and affordability for customers, while enhancing overall system efficiency.

I. INTRODUCTION

American Electric Power (AEP, hereafter referred to as the utility) owns and operates a vast electrical transmission and distribution network spanning 11 states. Across its service territory, the utility maintains approximately 1,350 transmission substations and more than 40,000 miles of transmission lines. On the distribution side, the company operates approximately 1,800 substations and serves end users through an extensive network of roughly 225,000 miles of distribution lines, making it one of the largest electric utility systems in the United States.

The financial outlook of the utility reflects an unprecedented period of infrastructure investment driven by growing energy demand and grid modernization needs. The utility has increased its 2026–2030 capital plan to \$78 billion, with visibility to invest more than an additional \$10 billion beyond the current plan [1]. This investment is supported by rapidly growing end-user demand, including 69 GW of incremental contracted load

expected by 2030, highlighting the scale of new industrial, data center, and economic development activity connecting to the grid [1].

The near-term outlook highlights the scale and urgency of the utility grid expansion efforts. In 2026 alone, the utility plans to invest approximately \$13 billion in capital projects while supporting 7 GW of incremental contracted load growth, reflecting the accelerating demand being driven by large industrial facilities, data centers, and broader economic development across its service territory [1]. As the volume of new substations and grid interconnections increases, traditional approaches to engineering and construction will be challenged to keep pace with deployment schedules.

To address these challenges, the utility explored and ultimately adopted the digital secondary system (DSS) approach, focusing on scalable architectures that enable faster deployment, commissioning, and life cycle management of protection and control (P&C) systems. After performing extensive research and acceptance testing, developing new DSS standards, commissioning and maintenance procedures, and operating several in-service stations, the utility is sharing experiences and lessons learned.

Once the utility selected DSS as a strategic direction, establishing standards became critical to achieving deployment at scale. As utilities pursue DSS modernization, standards provide the foundation for deploying new technologies at scale while maintaining reliability, safety, and cost effectiveness. Standardization enables repeatable engineering and design practices, leverages economies of scale in procurement, improves construction efficiency, and simplifies long-term maintenance and support. Equally important, common designs improve quality control, facilitate workforce mobility across geographies, and create a consistent operational environment that enhances human performance and safety. By focusing on life cycle value rather than initial project cost, standards help DSS investments deliver sustainable benefits across planning, engineering, construction, operations, and asset management.

A successful DSS roadmap must also balance innovation with disciplined change management. While emerging technologies can significantly improve data visibility, automation, communications, and operational performance, introducing new standards too frequently can create disruption, increase costs, and reduce productivity. For this reason, new technologies should be evaluated through structured pilot

programs, stakeholder collaboration, and documented business cases before being adopted as enterprise standards. Once proven, changes should be carefully governed through formal processes, clear communication, and user training for successful adoption. This approach allows utilities to continuously modernize their substations while preserving the stability, consistency, and long-term value that standardization provides.

DSSs offer an opportunity to reduce field wiring, standardize designs, simplify testing, and accelerate the delivery of protection, automation, and communications functions across a growing portfolio of projects. When combined with enterprise standards and disciplined technology adoption, these capabilities can help the utility deploy infrastructure more efficiently, improve consistency across projects, and support the rapid expansion required to serve increasing load while maintaining reliability and operational performance.

II. SELECTING A DSS SOLUTION

Over the years, power system protection technology has steadily evolved. Single-function electromechanical relays are often replaced by multifunction microprocessor-based relays that are prevalent on today's grid.

Within these systems, relays provide system protection against adverse conditions. They do this by monitoring current and voltage measurements, then providing reactionary control to primary equipment. These systems typically use current transformers (CTs) and potential transformers (PTs) in conjunction with secondary copper cabling to get the measured signals to the relays, and then, when needed, relays send control signals over direct-current (dc) circuits to primary equipment.

In such applications, relays reside in a control house with numerous long copper connections routed to the substation yard housing the CTs, PTs, circuit breakers, and more.

In the late 1990s and early 2000s, the concept of merging units (MUs) became more prevalent in P&C architecture discussions. An MU is a device that typically resides in the substation yard close to, or within, primary equipment. The purpose of this device is to digitize the measurement and control signals between the primary equipment and the relays. This approach is often referred to as a DSS.

Conceptually, there are several reasons why this alternative approach to secondary wiring for P&C systems can be beneficial for power system owners and operators, including simplified drawing packages, lower material costs, rapid deployment timelines, improved performance and monitoring, and increased operational safety [2].

There are two prevailing approaches to using MUs. The first is a network-based approach, leveraging Ethernet networks to share data between various relays and MUs. This approach relies on a protocol called Sampled Values (SV), which is defined within the IEC 61850-9-2 standard [3]. As part of this method, Global Positioning System clocks are required to provide time alignment for most protection functions.

The second approach uses a simplified point-to-point (P2P) architecture that eliminates the need for external time-

synchronization sources and Ethernet switch infrastructure. The communications between relays and MUs in a P2P system are nonroutable by design, reducing network complexity and limiting exposure to external communications paths. Measurements received from multiple MUs are inherently time-aligned within the protocol, providing synchronized data acquisition without reliance on external clocking systems. Additionally, the P2P MUs are nonconfigurable and do not require settings administration or firmware management, which further reduces deployment and maintenance requirements.

The utility conducted various tests and evaluations on both DSS architectures with promising results in leveraging the benefits that these systems can offer, including significant reduction of field wiring, panel quantities, comparative panel and control-house lead times, and improved system self-monitoring.

After testing both approaches, the utility chose to move forward with pilot projects and full standardization with P2P DSSs. This was due to the P2P DSS approach aligning more closely with conventional processes and practices than a network-based approach. The adopted solution offers MUs without settings or device management, requires no specialized networking knowledge for protection applications, and eliminates additional protection requirements such as a high-accuracy time source. The selection of P2P architecture established the foundation for the DSS program. The next step was developing the standards, drawings, settings, and work processes necessary to support utility-scale deployment.

III. CREATION OF DSS STANDARDS

Standards establish the guiding principles for transitioning to DSSs. Each new standard expands the knowledge surrounding the technology, addresses identified challenges, and establishes standard documentation to support training and propagation throughout the company. Without standards, transitioning from concept to production at a large utility scale is extremely difficult.

The utility maintains detailed standards for each protection application. Each standard includes detailed documents that support implementation by engineering and field teams, such as standard drawings, relay settings templates, Distributed Network Protocol (DNP3) lists, and application guides. These documents provide guidance for all the work performed on the utility system and serve as primary resources for understanding the standard and answering questions.

The utility is in the process of developing P2P DSS protection standards for lines, buses, transformers, shunt reactors, and shunt capacitors, as well as bay control and distribution station centralized protection and control (CPC) applications. Each protection standard contains several variations to cover different scenarios using the same protective relays. Examples of standard variations include single-phase versus three-phase transformers and various reactor-bank, bus, and line configurations.

During the standard development stage, existing protection philosophies and designs must be examined to determine whether changes or updates are required. Throughout this

section of the paper, several protection philosophy changes are discussed, along with the decisions made by the utility.

A. General Strategy

The strategy for transitioning to a P2P-based DSS focused on leveraging the similarities between existing traditional hardwired relays and new digital secondary relays. During the initial standards development, the utility strategically selected DSS-compatible models of existing standard relays when possible. This approach preserved many of the existing standards and facilitated a transition to DSS without a complete redesign. By minimizing the changes to the overall protection philosophy, the utility can focus education and demonstration efforts more on the new technology than on changes to the protection scheme.

Additionally, as part of their overall strategy for P&C, the utility uses two fully redundant systems for both transmission and distribution. This practice ensures reliability as well as compliance with applicable standards. As such, during the transition to DSS, careful attention must be given to maintaining those two fully redundant systems. Placement of MUs, selection of dc power, assignment of tripping outputs, and sharing of MUs between relay systems must all be considered. The loss of a single MU must not disable both the primary and backup protection systems or impair the ability to trip using both trip coils. The philosophy of preserving proven protection concepts while minimizing workflow disruption guided many DSS design decisions.

B. MU Selection and Placement

When selecting an MU strategy for a DSS, there are several options for MU placement near or within the equipment, depending on space constraints and the number of MUs required. MUs can be installed inside equipment cabinets, mounted to the outside of equipment, or housed in independent pedestal-like cabinets located near monitored and controlled equipment. When the size of the MUs makes placement inside existing equipment cabinets difficult or impossible without a complete cabinet redesign, independent pedestals (i.e., cabinets designed to attach to the support structures of existing equipment) are often used as an intermediary that can be standardized and deployed across the system.

When using P2P DSS technology, the number of resulting connections must be considered when placing MUs, as there are a fixed number of ports available on both the DSS relays and the MUs. For example, while placing one MU per phase on a single-phase transformer may seem logical, this implementation would use three of the eight ports the utility has available on the selected relay. Likewise, the selected MUs can connect to up to four different relays. Therefore, at a bus PT or coupling capacitor voltage transformer (CCVT), where more than four relays need to connect to an MU, additional MUs will be required.

With these considerations in mind, the utility decided to place MUs at each piece of equipment that provides data to or requires an output from the relay. This includes placing MUs at each line or bus PT and CCVT rather than running cables to an MU located at the nearest breaker, which has both advantages

and disadvantages. A significant advantage to this approach is separation of the MUs, such that standard MU input/output (I/O) layouts can be created and combined across different application standards. One disadvantage to this approach is that it increases the number of MUs and MU cabinets. Careful consideration must be given when designing the standards to ensure the number of required port connections does not exceed the capabilities of the selected hardware.

The number of MUs installed at each piece of equipment varies based on the standard design. In the utility designs, a typical breaker has four MUs located either in the control cabinet or in a pedestal nearby. This breaks down to two MUs for the application on one side of the breaker and two MUs for the application on the other side of the breaker. The utility needs four MUs to meet the redundancy requirements and for the multiple-manufacturer system, which was carried forward from the conventional utility standards. While not the standard practice of this utility, using a single manufacturer could reduce the number of required MUs because the P2P MUs are optimized for each manufacturer and are not interoperable. Therefore, a single-manufacturer system provides more opportunity for sharing MUs between devices.

The primary MU selected, which is applied wherever practical, includes four CT and four PT connections. However, one common exception to this includes transformer applications where an MU model with eight CT connections is used. The eight CT inputs allow currents from both sides of the transformer to be wired into a single device. A similar approach could be taken when currents from both sides of a breaker are required.

This discussion demonstrates that an important aspect of DSS standards is the selection of MU locations, quantities, and types, as these factors drive other design decisions.

C. Design Considerations

When developing P&C standards using P2P DSS technology, existing application standards, the selected MU integration strategy, and desired DSS feature sets may result in significant variation for what the ideal DSS solution looks like for each user. This section introduces several areas of consideration and shares the utility approach.

1) Relay Settings

It is possible to maintain relay operating principles, protection elements, and custom logic when transitioning to a DSS. The primary changes are related to new settings, which define the connected MUs, the relay-to-MU port connections, and the digital mappings between the MU and relay I/O, as well as between the MU data streams and relay internal current and voltage sources. Some DSS relays maintain the same current and voltage winding nomenclature present within the conventional relay models, which further reduces the number of settings changes when transitioning to a DSS.

While many of the relay settings can be preserved, there are new features available in DSSs, such as active link monitoring. This feature allows the relay to be configured to alarm, disable select protection elements, or switch to alternative signals if communications with an MU are lost.

The utility implementation consisted of a like-for-like approach where practical, with additional logic implemented for DSS health monitoring. The utility was able to directly translate the core protective functions and primary relay logic from the existing standards. However, a minimal amount of relay logic had to be altered or added to adapt to the new P2P connections. Minimal changes were made to the relay front-panel displays, limited to additional alarms to display issues with the P2P technology.

It should be noted that not all relays or control schemes are directly adaptable today to P2P due to some manufacturer devices not supporting P2P technology. Ultimately, some protection schemes were updated by changing the relays to DSS-compatible relays or through minor philosophy changes to adapt to the technology. In the future, some control schemes will require editing or different control inputs to adapt to a DSS environment.

2) Tripping and Closing Philosophy

One of the most significant design considerations is the approach to breaker tripping and closing. While this may seem straightforward, there are several different options to consider with benefits and drawbacks for each. One approach is to set each device to trip only the previously assigned trip coil. A second option is to set each device to simultaneously trip both trip coils. A third option is to assign each MU tripping output in a way that minimizes MU-output sharing between relays and functions. For example, the MU may have one output assigned to a protective relay for the initial protection trip, a different output assigned for a breaker failure (BF) trip or retrip, and possibly a third output assigned for a different reason, such as locking out the breaker. Each of these options ultimately accomplishes a similar end. The utility selected an approach in which different applications use different outputs. A simplified diagram showing this approach for a line and bus breaker application is illustrated in Fig. 1.

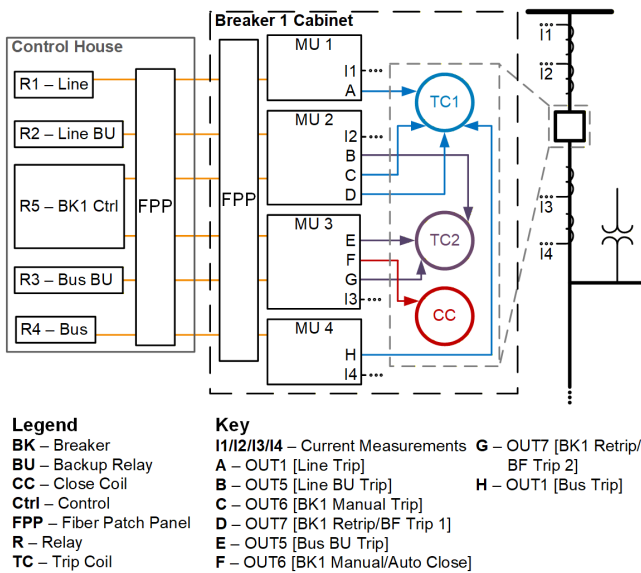


Fig. 1 MU Outputs for Breaker Tripping and Closing

In some cases, a single MU trips the same trip coil from different outputs. The advantage of this method is that it keeps

the applications separate. It is easy to tell whether the breaker relay (BR) is the device that trips the breaker, since all of the relays connected to that MU can monitor that same output. This method also increases flexibility in the field by maintaining the separation of relay-system tripping outputs, such that each relay ideally has an MU tripping output per breaker, which can be isolated through a traditional test switch. This allows field personnel to fully isolate a single relay by physically opening the trip circuit without affecting the other relays that trip through the same MU. The settings also remain as consistent with the traditional copper secondary substation variant as possible.

3) Lockout Relay Implementation

Another significant change is lockout relay implementation. Lockout relays (86) are used to trip for bus faults, BF faults, transformer faults, etc. via direct wiring to breaker trip coils in the conventional designs of the utility. A common bus lockout application is depicted in Fig. 2 for reference.

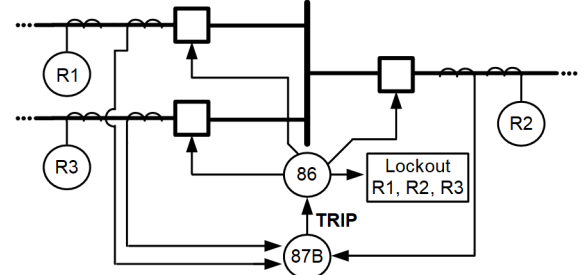


Fig. 2 Standard Lockout Relay Application

With a full DSS solution, trip and close circuits are no longer available in the control house, so lockout relays can no longer physically lock out or trip a breaker. In contrast, the lockout signal must now go through one or more relays connected to the correct MU(s) to trip the breaker(s). In addition, the lockout must now tell the relay(s) controlling the breaker(s) to enter a lockout state, using either virtual lockout logic or a digital input. This is a significant departure from the physical act of opening a connection on the close string of the breaker to cause the breaker to lock out.

Due to the breaker lockout being implemented in relay logic, DSS lockout philosophy is highly configurable. All logic for the lockout and breaker-closing prevention can exist in one relay, be distributed among multiple intelligent electronic devices (IEDs), or use an auxiliary device, such as a traditional lockout relay, as a contact multiplier to transmit the lockout signal to other IEDs.

Certain MU models offer the option to lock out a breaker using Form B contacts that can be held open to mimic a traditional lockout relay. This method offers a feature where each relay connected to the same MU can monitor each output status of the MU, facilitating easy lockout-status sharing between all relays connected to the MU performing the Form B lockout. This option presents a deviation from traditional lockouts and would require updates to P&C design philosophy.

To address the migration to a DSS, the utility implemented two notable lockout design alterations. The first design alteration includes maintaining the panel lockout relays for use

as auxiliary relays to signal the breaker control relays to either trip or lock out, depending on the scheme. The BF lockout relays signal adjacent breaker control relays to trip and lock out, while protection lockout relays (bus, transformer, line, etc.) signal all appropriate breaker control relays to lock out. The second design alteration includes connecting the relays to all necessary breaker MUs to trip the breakers directly, where feasible. This combination allows for the relays to mimic the existing scheme and provides the fewest settings changes.

For BF lockouts, the utility implemented a digital lockout latch within each breaker control and failure relay. This design makes the BF relay responsible for tripping and locking out the breaker for adjacent BF scenarios. Within this design, BF lockout tripping consists of tripping both Trip Coil 1 and Trip Coil 2 via its connected MU for the breaker. To maintain field familiarity, the choice was made to include a traditional lockout relay on the BF relay panel to transmit the BF signal to the appropriate breaker control and lockout relays via hardwired relay inputs. A comparative bus lockout relay application is illustrated in Fig. 3.

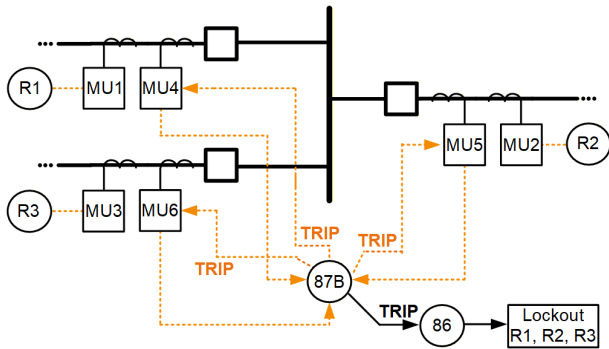


Fig. 3 DSS Lockout Relay Application

D. Drawing Packages

The P&C drawing package must be reviewed and updated when transitioning conventional P&C designs to DSS designs.

MUs must be included in the alternating-current (ac) and dc schematics, and detailed fiber drawings must be developed to document the end-to-end connections between the relays and the MUs. The addition of new functional drawings may be required due to differences between conventional and DSS designs.

The utility chose to implement multiple new concepts in their standard drawings to support DSSs. The first drawing affected was the one-line diagram. Since the utility includes relay connections on the one-line diagram, it also chose to include MUs on the one-line diagram for DSSs. The utility developed multiple iterations of one-line diagrams with MUs before selecting a simple representation for each MU while maintaining the existing relay symbols. These symbols include the internal current and voltage source information, which was deemed to be valuable to retain on the DSS one-line diagrams. The digital connections between the MUs and the relay currents and voltages are represented with dashed lines, as shown in Fig. 4.

Like the one-line diagram changes, the utility discovered that the relay ac schematics also required updates for DSS due to the physical decoupling of the instrument transformers and relays. The utility deemed it insufficient to simply swap out the relays with MUs in these drawings. It would show the ac wiring of the MUs, but it would not show the digital connections between the MU currents and voltages and the relay internal current and voltage sources. To address the issue, the utility developed a concept similar to the one-line diagram improvements, in which dashed lines were also added to the ac schematics to represent the digital connections between the MUs and the connected relay current and voltage sources. An example of this concept applied to a current circuit is shown in Fig. 5. This solution allows field personnel to clearly identify where each relay receives the analog data without needing to reference relay settings. This solution also reduces process changes for the utility field personnel who are accustomed to referencing drawings during testing and commissioning.

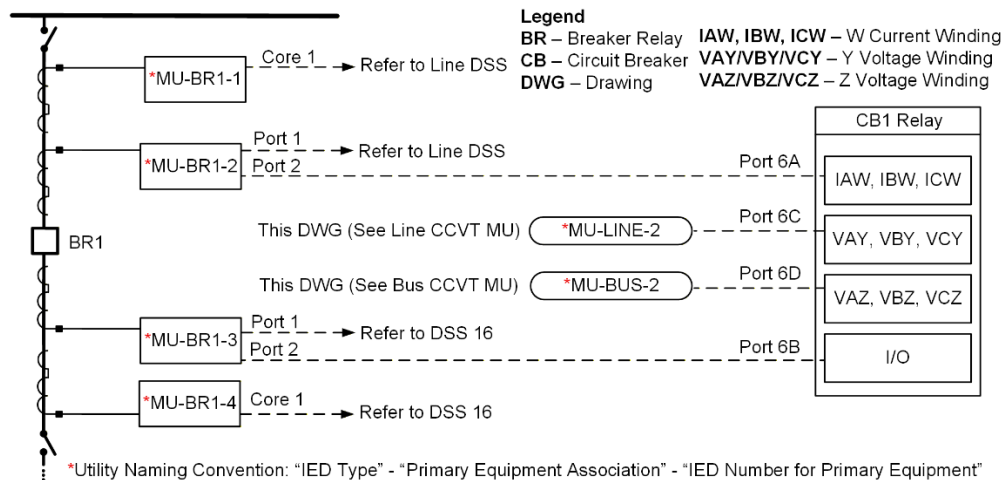


Fig. 4 The Utility DSS One-Line Diagram Example

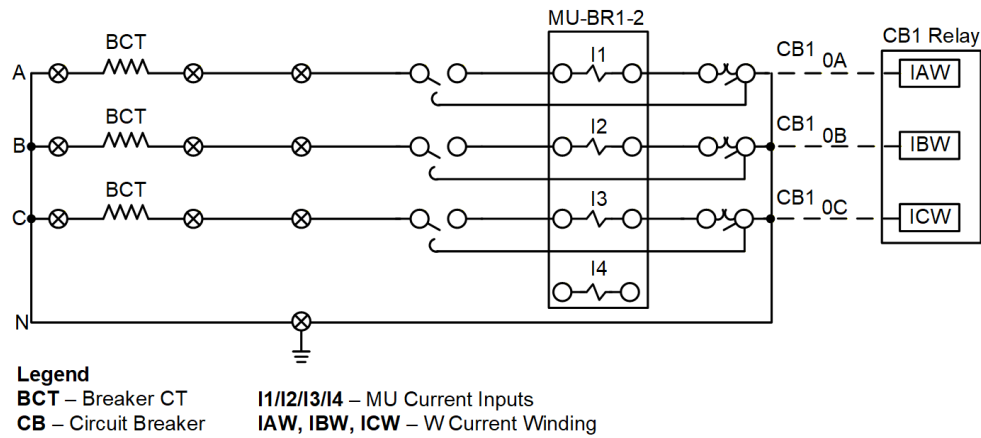


Fig. 5 The Utility DSS Relay AC Schematic Example

Changes were also made to the relay dc schematics due to the simplification of the drawings with the DSS approach. In DSS designs, much of the relay I/O is physically moved off the relay and into the switchyard, so naturally the relay dc schematics include less information when compared to conventional systems. New MU dc schematics were created to detail the MU I/O, but this was deemed insufficient as it was not readily apparent which I/O was controlled by each connected relay. To avoid requiring field personnel to reference relay settings to see this information, the utility piloted the addition of remote I/O tables in the relay dc schematics. These

tables show the MU I/O mapped to a given relay. An example of one of these tables is shown in Table I.

Even with these drawing updates, additional drawing improvements may be required when implementing DSS depending on the amount of digitization. If all relay-to-relay signals are digitized using a method such as Generic Object-Oriented Substation Event (GOOSE) protocol, additional drawings showing the relay logic and networking path may be considered. The current utility implementation of P2P DSS does not require these additional details since the process bus data are communicated over direct fiber-optic links and not over a network.

TABLE I EXAMPLE REMOTE I/O IN RELAY DC SCHEMATICS

79/551-CB1 Relay MU Remote I/O			
	MU	Contact	Function
Outputs	MU-BR1-2	OUT06	MANUAL TRIP
		OUT07	RETRIP/BF TRIP 1
	MU-BR1-3	OUT06	CLOSE
		OUT07	RETRIP/BF TRIP 2
	MU-LINE-2	NONE	N/A
Inputs	MU-BUS-2	NONE	N/A
	MU-BR1-2	IN01	CB 52A
		IN04	CB 52B
		IN05	CB ALARM 1
		...	...
		IN12	CB ALARM 8
		IN13	CB TRIP COIL MONITOR 1
		IN16	MU TEST
	MU-BR1-3	IN01	CB 52A
		IN04	CB 52B
		IN13	CB TRIP COIL MONITOR 2
		IN16	MU TEST
	MU-LINE-2	IN16	MU TEST
	MU-BUS-2	IN16	MU TEST

IV. ELECTRONIC SECURITY PERIMETER AND NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION CONSIDERATIONS

In North America, the North American Electric Reliability Corporation (NERC) maintains and enforces multiple standards surrounding the use of IEDs for the P&C of the bulk electric system (BES). An IED designed and used for this purpose is known as a BES Cyber Asset (BCA). One or more BCAs make up a BES Cyber System (BCS). Compliance with these standards is mandatory if the asset or assets are identified as part of a BCS.

The adoption of process bus architectures and yard-based MUs introduces new considerations for applying NERC Critical Infrastructure Protection (CIP) requirements at medium-impact substations. The utility prefers the implementation strategy of using nonroutable P2P communications between protection relays located within the control building and the MUs located in the field-mounted equipment cabinets. This architecture enables many of the operational and life cycle benefits of DSSs while minimizing the cybersecurity complexity often associated with network-based process bus implementations. For medium-impact facilities, the primary compliance consideration is NERC CIP-006-6 R1, Part 1.1 (physical access control), which can be addressed through physically secured MU cabinets and access controls aligned with existing medium-impact physical security practices.

A key aspect of this strategy is the distinction between BCA classification and electronic security perimeter (ESP) requirements. The MU may reasonably be considered a BCA if its loss, degradation, or misuse could adversely impact the operation of a BES protection system within 15 minutes. Because the MU performs an essential role in collecting and delivering current and voltage information to the protective relay, a malfunction or compromise could have a direct impact on protection system operation. Consequently, the determination of whether a device is a BCA should be based on its effect on BES reliability rather than whether it supports routable networking, remote access, or firmware updates.

While the MU may satisfy the criteria for a BCA, the position of the utility is that the presence of a BCA alone does not automatically require extension of the ESP into the substation yard. NERC CIP-005-7 is focused on the protection and monitoring of Electronic Access Points (EAPs) and externally connected communications endpoints that provide a path for electronic access into a BCS. In the proposed architecture, the MU communicates exclusively through dedicated P2P, nonroutable connections and does not provide a routable network interface, remote access capability, engineering workstation access, or any other practical means of electronic entry into the station network. As a result, the MU does not introduce a new EAP that would require expansion of the ESP beyond the control house.

This distinction is important because the security risk associated with the yard-based MU is fundamentally physical rather than electronic. An individual cannot gain access to the station network, relay configuration, or other BCAs through the

MU communications interface because no routable path exists. The only credible method to affect the device is through physical access to the equipment cabinet. Therefore, applying physical protection measures under NERC CIP-006-6 directly addresses the primary threat vector without creating the additional compliance burden associated with extending the ESP into the yard. This approach maintains a clear and defensible relationship between the applied security controls and the actual risk presented by the device.

Under this model, the ESP remains bounded by the control house, where the station network, protective relays, and other network-connected BCAs reside. The nonroutable communications links between the relay and the MU are treated as dedicated communications paths rather than EAPs. Accordingly, the ESP remains unchanged while the yard-mounted equipment cabinets receive appropriate physical security protections, such as lockable enclosures and controlled access by personnel already authorized for medium-impact facilities. This preserves the cybersecurity architecture used today, while allowing DSS technologies to be deployed outside the control building.

As DSSs continue to evolve, the long-term objective of the utility is to minimize or avoid routable communications outside the control building wherever practical. Maintaining nonroutable process bus architectures reduces compliance complexity, limits potential electronic attack surfaces, and allows cybersecurity programs to focus on protecting actual EAPs rather than extending ESP boundaries throughout the switchyard. Future projects will continue to evaluate emerging technologies, end-user-owned facility applications, and evolving NERC CIP requirements, including NERC CIP-004-8. However, the current approach provides a practical framework for deploying DSSs while maintaining a strong cybersecurity posture and a clear separation between BCA classification and ESP applicability.

V. THE UTILITY EXPERIENCE

A. Design Standard Challenges

The standards development plan spans many applications and allows for the normalization of operation and control. However, not all situations can conform exactly to the standards. DSS standardization is especially challenging in hybrid and brownfield substations.

1) *Mixing Traditional Copper and DSS Within Hybrid Stations*

When transitioning from a traditional substation to a DSS substation, some scenarios may require mixing traditional copper and DSS solutions. This could be due to the desire to pilot the technology on a single line or because a scheme is awaiting a DSS solution, but the substation needs to go into service. While it is possible to develop solutions for these projects, it can be challenging to apply a standard to the application and can create confusion.

One challenge is the number of physical I/Os on the DSS relays as a result of their design. Recently, some DSS relays have been released with additional physical I/Os on the relay

board. However, each additional board reduces the amount of I/Os available to be digitally mapped for the MUs. Many blended copper and DSS solutions use physical I/Os for relay-to-relay communications and thus create a bottleneck.

Another challenge is design philosophy. Simple functions, such as tripping a breaker for a lockout operation, become more difficult in a hybrid application. For example, if a BF relay uses DSS and operates a traditional lockout relay, should the lockout relay trip all breakers directly, only the breakers not using DSS, none of the breakers, or a combination of options depending on the surroundings? While the lockout relay may physically lock out the non-DSS breakers, it can virtually lock out the DSS breakers. This adds complexity to the P&C design.

A third challenge lies in testing and maintenance. Testing and maintaining a hybrid substation requires different philosophies and practices to be used in different areas of the substation. This includes differences in device isolation, relay testing, and possibly the equipment required for testing. These differences are explored in the Testing, Commissioning, and Maintenance section of this paper.

The final challenge noted is an operational philosophy limitation. Since DSS relays operate the devices in the field based on programming, physical elements such as block close strings lose the practical effect because they are no longer located in the control path. In a copper station, disrupting the close breaker control path would result in preventing the breaker from closing. In a DSS station, disrupting this path may or may not result in preventing the breaker from closing depending on the programming and how it is reset. Moving these functions from physical to digital does not reduce the reliability or safety of operation, but it does change the operational philosophy within the substation, where some substation device close supervision can be reset using the lockout relay, while others must be reset at each individual breaker control relay.

2) *Brownfield Substations*

Brownfield substations pose a particularly difficult challenge. These substations often contain older relaying, cannot be fully removed from service, and are irregular when compared to new, standardized greenfield substations. Implementing a DSS solution in a brownfield substation can generally follow one of two approaches—either a full replacement or a partial replacement. Both options require existing equipment to be retrofitted with MU cabinets located in the substation yard. The location, age, and style of the equipment may vary significantly in these types of installations.

A partial replacement or hybrid substation approach is particularly difficult with a brownfield substation due to the wide variety of potential relay types. The interactions of DSS relays and electromechanical relays may not be the same compared to more modern microprocessor relays. One method to save I/O for a DSS hybrid conversion is to explore the use of IEC 61850 GOOSE messaging for relay-to-relay control signals. This may not be possible in a brownfield substation depending on the age of the relays. Additionally, adding legacy functionality such as control handles to a DSS may be impractical. Although this type of hybrid substation is feasible,

it may be inefficient and add confusion in a hybrid greenfield substation.

A full replacement of relaying in a brownfield substation may be easier, as the implementation can be planned around the installation of the new protection and any compromises are temporary.

With this strategy, it is possible to maintain the existing protection during the installation of the new MU cabinets. By installing the test switches in the cabinets, the wires can be installed and the MUs removed from the current, voltage, and trip circuits until the protection is ready to be used.

3) *P2P With Multiple Manufacturers*

Proprietary P2P DSS installations with multiple manufacturers introduce additional complexity when trying to effectively leverage the new technology. Using multiple manufacturers may require additional MUs, and it reduces the potential for interoperability offered by DSS technology. One major advantage of DSS is the capability for plug-and-play applications, where the loss of an MU can be quickly addressed by swapping in a replacement unit or, potentially, by moving the fiber connection to a functioning MU until a replacement can be installed. With multiple-manufacturer systems, this advantage is lessened because there is less overlap between the MUs. Additionally, any software advantages designed to make creating, installing, and programming devices simpler in a DSS may only be available on one of the two or more manufacturer systems.

Conversely, two-manufacturer solutions can maintain hardware and algorithm diversity in the P&C design. This can be beneficial to help cover any gaps as DSS technology evolves.

B. *Application Examples*

The utility currently has multiple in-service DSS applications with additional installations in progress. This section of the paper examines three examples of commissioned DSS installations. The first is a breaker-and-a-half installation at a hybrid substation featuring line and breaker protection. The second is a bus relay installation at a brownfield substation. The third is a centralized P&C design that uses DSS.

1) *Example—Line Protection and Breaker Controls*

The utility has piloted DSS on one 138 kV transmission line and both line breakers at a new greenfield substation. Some of the challenges faced throughout the design and implementation of this project are summarized below.

The first design limitations encountered were the I/O limitations present with the DSS relays. The utility completed this project before the I/O board expansions became available on select DSS relays, and additional I/O was needed for interfacing with the conventional schemes. Thus, an extra device was required to be added to the DSS breaker control relays to provide extra I/Os. The extra device was connected using a serial-to-fiber converter and communicated with the relay digitally.

For this installation, the utility leveraged a hybrid design for the measurement and control circuits of the associated breakers by including local MU integration while maintaining hardwired

connections for use with traditional relaying systems that provide protection for adjacent zones. In the context of a pilot project with a hybrid substation design, this makes logical sense because it allows the traditional copper relaying to maintain all functionality without needing to interact with the DSS equipment. Since the relaying was not being replaced due to a problem such as age or distance, there was no reason at this installation to use DSS relaying as a medium for tripping from the traditional relays. However, this creates scenarios where traditional relaying and DSS relaying operate differently. One notable difference is circuit breaker lockout. The circuit breakers with traditional BRs use traditional hardwired lockout circuits, while the two DSS line breakers use a virtual lockout through the DSS breaker control relays.

Traditional utility designs include a hardwired emergency trip (ET) switch on the BR panel for each transmission breaker. The decision to maintain the copper cables at this installation meant the ET switch for the DSS breakers could still be hardwired; however, this design was not selected. In a fully DSS substation, the ET design must be rethought because there is no copper trip circuit to the breaker from the control house. The utility chose to maintain the ET switch but repurpose it to trip the BF lockout relay. This design allows both zones on either side of the breaker to be cleared in the event of an emergency situation in which the BR or its MUs have failed. The utility also implemented a time-delay control switch (see Fig. 6) in the breaker cabinet to provide a hardwired trip and close path to the breaker for nonemergency situations. This time-delay control switch provides an instantaneous trip or close, as well as a 10-second delayed operation.



Fig. 6 Circuit Breaker Time-Delay Control Switch

2) Example—Bus Protection

The utility implemented DSS bus protection on a 138 kV bus at one brownfield substation to replace failing

electromechanical relays, installing MUs in pedestals in a manner that is different from the standard application. Since it is a brownfield application, MUs were given their own dc power and one MU received analogs from multiple breakers. This varied from the standard design (installing a number of MUs per piece of equipment) because the design was completed before the standard was finalized. Each pedestal covered two breakers, with a third pedestal dedicated to the transformer. The shared pedestal reduced the space required for the DSS installation. Notably, the transformer low-side circuit breaker was tripped through conventional copper cables since it did not have an associated MU. This decision allowed the DSS installation to remain on the 138 kV side of the transformer, while preserving a traditional copper design on the 69 kV side. An example one-line diagram of this design is shown in Fig. 7.

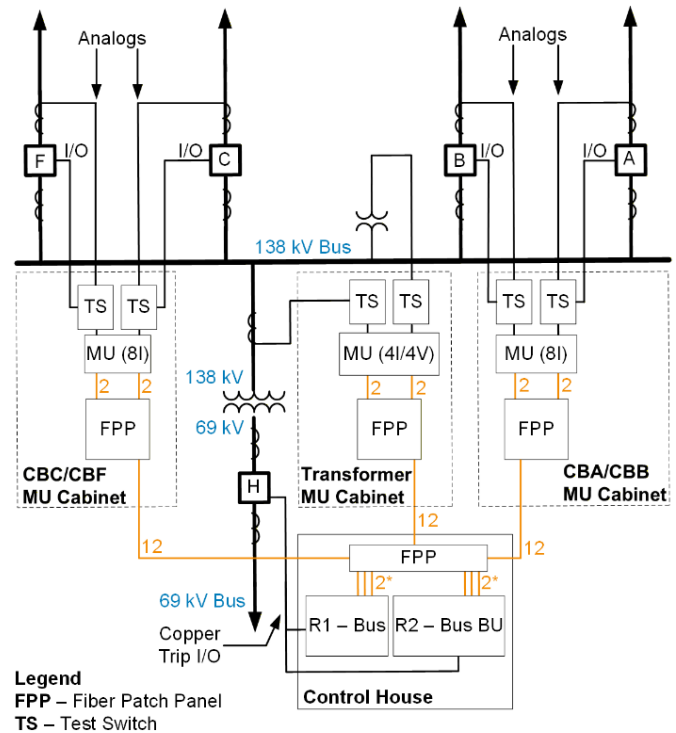


Fig. 7 DSS Bus Relay One-Line Diagram

This installation demonstrates the capability for P2P DSS to be implemented in a wide range of scenarios, although brownfield installations present unique challenges. This solution takes advantage of the remote analog data and tripping for most breakers and allows the substation to begin the transition to an entirely DSS substation while maintaining current functionality and operability.

3) Example—Consolidated P&C

In addition to translating conventional transmission applications to leverage the benefits of DSS, the utility has been actively researching the feasibility of consolidating P&C functions to reduce device count in the control house. The current standard CPC solution is a P2P DSS solution consisting of MUs, two CPC relays for redundancy, and a multifunction data gateway, as depicted in Fig. 8. The technical details of this design are discussed in detail in [4].

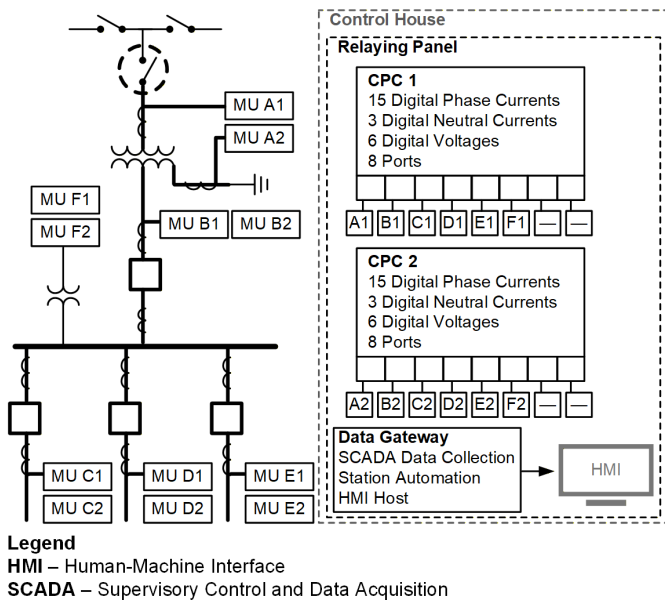


Fig. 8 Example CPC Station Design [4]

CPC solutions with DSS offer unique benefits but also introduce new challenges when compared to the distributed DSS designs that the utility has developed for transmission applications. For this reason, the utility currently reserves the adoption of CPC DSSs for select distribution substations that meet the predefined scoping criteria of the CPC standard.

One significant change in the CPC standard when compared to the utility transmission DSS solutions is the introduction of a human-machine interface (HMI). CPC often forces the use of an HMI for operator intervention due to the limited number of pushbuttons on a centralized device. To address this challenge, the utility chose to implement an HMI hosted on the data gateway.

The HMI is a new addition to substation P&C at the utility, so new processes and standards had to be developed to support it. The utility discovered that engineering teams must be equipped to develop the HMI files for each CPC standard project, and small deviations in substation topology can require additional work to update the standard HMI. Additionally, field personnel must be trained to operate the substation via the HMI instead of distributed relay controls.

While the introduction of an HMI can pose challenges, it also offers potential benefits. The standard HMI of the utility includes a visual overview of the entire distribution substation along with real-time data such as breaker statuses and power flows. The HMI also allows quick access to critical system health information such as active protection zones, system alarms, and operational notes. These are powerful visual awareness tools for field personnel to quickly assess the state of the substation, and this is a significant improvement for the utility over the distributed visualization through independent relay front panels available in non-CPC solutions.

While there are notable differences between CPC and distributed DSS solutions, the experience of the utility is that there are many areas where CPC and DSS technologies can be merged to complement one another. Both technologies reduce

control house and panel space, and the utility leveraged the two together to further reduce the Drop-in Control Module (DICM) size for a pilot project.

In addition to smaller P&C footprints, both technologies reduce copper wiring in the substation. Copper reduction in the yard is achieved through DSS, and CPC takes an additional step in virtualizing interpanel wiring in the control house within the CPC device. The utility aims to leverage these properties of DSS and CPC to improve project construction timelines.

Overall, the CPC and DSS architecture represents a significant departure from traditional distributed protection schemes; however, there is overlap with the distributed DSS schemes of the utility. The deployment of the CPC standard provides the utility with a practical implementation of CPC technology and serves as a foundation for evaluating its performance, operational benefits, maintenance implications, and long-term scalability across future substation projects.

VI. TESTING, COMMISSIONING, AND MAINTENANCE

One of the largest perceived barriers in implementing a DSS is the distributed nature of the devices, which introduces new challenges to commonly used testing methods where test signal generation and the protection device are often in the same physical location. This section reviews the journey of the utility through acceptance testing, field team training, and the adaptation of existing processes to commission DSS schemes.

The utility has gained significant experience with P2P DSSs through the successful deployment of multiple generations of early pilots and partnering with manufacturers to refine features of the technology. Like conventional systems, this process began with lab testing and verification. All standard DSS relays and MUs were installed in the lab, mimicking the newly developed DSS standard applications, with the addition of lab-specific test-plug panels to break out all relay and MU I/Os for testing.

The lab environment was leveraged to test the DSS solutions to verify that they functioned properly and performed at the same level, or better than, existing standards. Secondary injection test sets and associated software were used to simulate realistic system events and perform injection into the MUs. The relay response was then recorded and validated. Real-time hardware-in-the-loop testing was also completed for each pilot project to validate the design and settings. The method of secondary injection into the MUs was also used for hardware-in-the-loop testing.

Early in this process, numerous field services team members were brought into the lab to gain hands-on experience and collaborate on the development of processes and custom relay logic to enhance the testing, commissioning, and deployment of the DSSs. This step was crucial in multiple regards. It was instrumental in the development of standard settings that aided testing and commissioning activities for DSS schemes. It was also instrumental to the adaptation of existing conventional test plans to work with the DSS. Lastly, it helped facilitate knowledge transfer from the standards subject matter experts to the field services organization, which is anticipated to be necessary as DSS deployments continue.

After the development of the standards, the utility then took steps to integrate this technology into select portions of projects (e.g., a singular bus or line protective relay package), allowing for targeted real-world experience and the ability to refine deployment of this technology before taking larger steps. Currently having deployed multiple P2P DSS pilot projects, the utility is moving ahead with finalizing and rolling out enterprise standards leveraging this technology.

Based on experiences thus far, the utility has identified several key areas to consider when testing DSSs.

A. Manufacturer Equipment Integration

Due to rapidly growing demand in the power industry, it has been an increasingly common trend to experience historically high lead times for primary equipment.

When discussing the adoption and implementation of DSS technology, this trend has had a direct impact on the ability of an end user to rapidly implement and test new DSS designs that integrate MUs into the primary equipment control cabinets. Integrating MUs into the primary equipment control cabinets is highly desirable because it allows MUs to arrive at the utility site prewired and pretested in the factory.

These challenges may lead many initial DSSs to be deployed with conventional primary equipment that has been adapted in the field to integrate MUs into the existing cabinets (if space allows) or by using additional freestanding cabinets. Extra yard cabinets can increase material cost, project time, and complexity; however, they allow for the exploration of DSS technology without relying on manufacturer integration timelines.

Recently, the utility has made substantial progress in this area, partnering with many of their manufacturers to evaluate (and in some cases finalize) the design for incorporating MUs into standard equipment cabinets. The integrated devices have already completed P2P wiring checks, general power-ups (enabling and passing self-tests), digital I/O validation, and analog input validation. Notably, this requires the utility and the manufacturer to develop a method for MUs to be easily tested in the factory. The solution incorporates a DSS relay with special settings optimized for manufacturer testing (i.e., input visualization, output pulsing, and analog metering validations). The utility plans to leverage this optimization to gain both time and cost efficiencies during future DSS deployments to meet operational goals.

B. Secondary Cabling

In the traditional designs of the utility, connections between primary equipment CTs, PTs, alarm contacts, and trip and close coils are prewired to terminal blocks in the equipment cabinets. On the control-house side, the utility has implemented a DICM design in which relay panels are prewired within a control building and shipped to site as a complete assembly. The relay panels include test switches for easy isolation and testing. Although both approaches aid in the simplification of field wiring, numerous copper cables must still be tagged, pulled through trenches, properly terminated, landed, and P2P-checked for continuity and accuracy between the DICM terminal blocks and the primary equipment terminal blocks. A

simplified one-line diagram of the secondary cabling in a conventional relay system is shown in Fig. 9. Note that the backup relay has been omitted for simplicity in Fig. 9, Fig. 10, and Fig. 11.

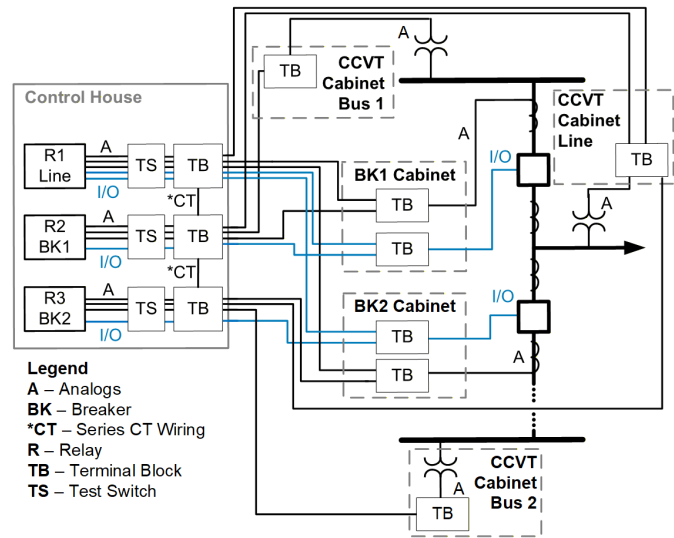


Fig. 9 Secondary Cabling in a Conventional Relay System

With DSSs, the secondary cabling design changes depending on the selected DSS architecture. When pursuing DSS, it is sensible to evaluate the digitization of relay-to-relay control signals (BF initiate, lock out, reclose initiate, alarms, etc.) from hardwired I/O to peer-to-peer or networked digital communications to further reduce cable counts. The utility is actively investigating these solutions in the lab environment, but the current iteration of DSS standards maintains hardwired relay-to-relay I/O to limit the scope of changes for field services and engineering teams.

In the switchyard, the control cables are removed and replaced with fiber-optic links between the relays and MUs. The utility has implemented a yard fiber design where multiple fiber patch panels are used instead of continuous fiber cables. This design supports preterminated fiber connections between the devices and patch panels, which significantly reduce the total number of fiber splices that must be made onsite.

As mentioned in the Manufacturer Equipment Integration subsection, the intermediate utility DSS designs have included independent MU cabinets in the yard. In these scenarios, copper cabling must still be connected between the primary equipment terminal blocks and the MU cabinets, which is typically a much shorter distance than conventional systems. Additionally, test switches are relocated to the MU cabinet to replicate the test switch on the relay panel in a conventional design. A simplified diagram of the secondary cabling in the intermediate utility DSS is shown in Fig. 10.

Within their current standards, the utility has chosen to implement a centralized yard fiber cabinet at transmission stations, allowing the use of a consolidated home run fiber cable to be run most of the distance into the yard to support rapid integration of primary equipment during future substation expansion. For simplicity, the second cable run and backup system is not shown in the diagram (see Fig. 11).

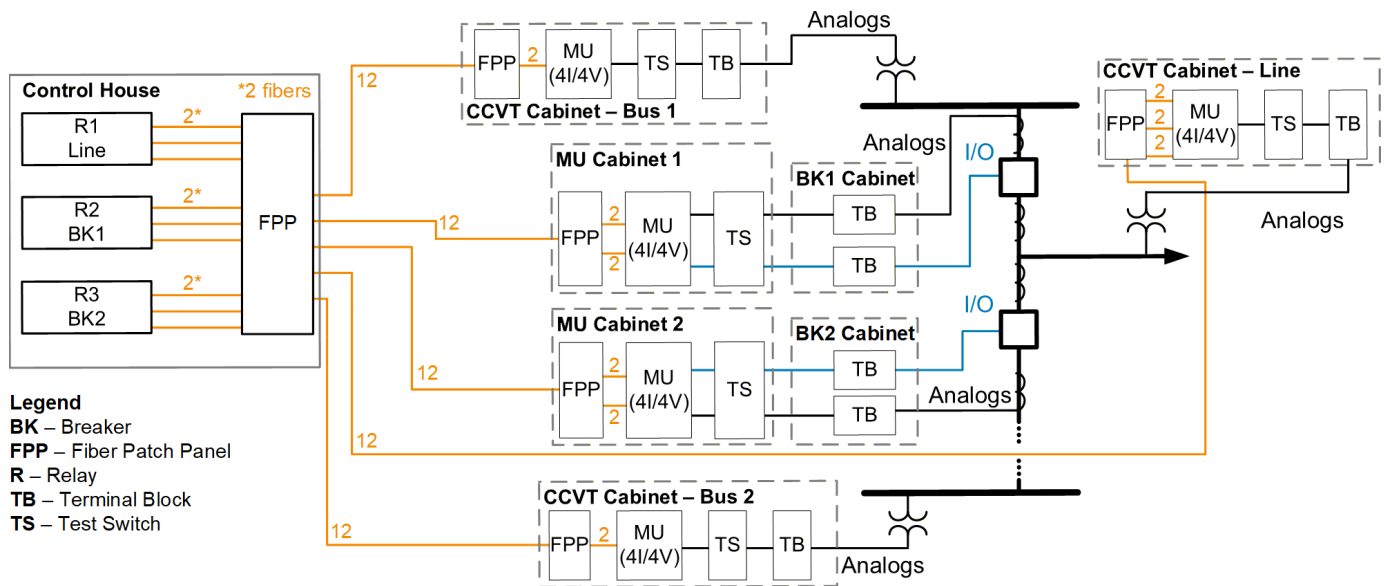


Fig. 10 Secondary Cabling in an Intermediate DSS

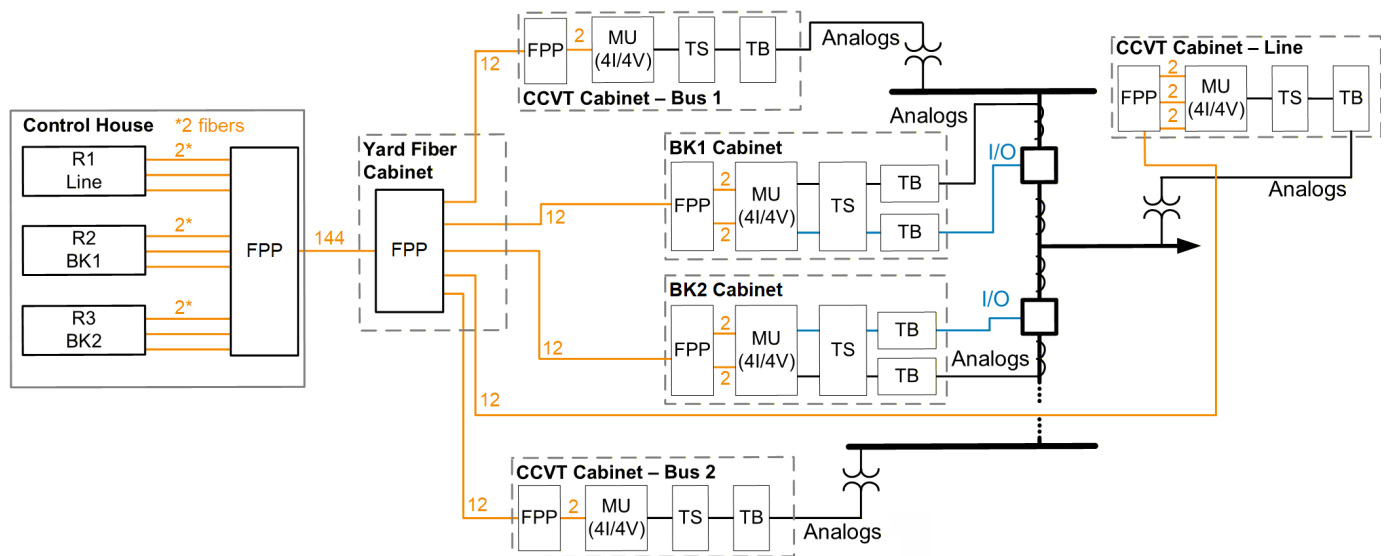


Fig. 11 Secondary Cabling and Standard DSS Design

C. Relay Settings

In collaboration with the field services teams, the utility standards team developed new settings tools to aid in the testing and maintenance of DSSs. Three of these new tools are MU Test Mode, MU Out of Service, and the implementation of the IEC 61850 Blocked Mode.

1) Merging Unit Test Mode

The utility developed an MU test mode concept based on the status of an MU binary input. DC is wired through a normally closed test switch into an input on each MU. These MU test inputs are continuously asserted under normal operation. However, when the test switch is opened, the test input will drop out, causing all connected relays to generate a front-panel message indicating that the specific MU is in Test Mode, generates an abnormal system condition alarm and enables a virtual switch within each connected relay to enable certain test and maintenance operations. For example, breaker trip testing through the MU is supervised by the MU test switch so that

only an MU in Test Mode can trip the breaker for a manual trip test operation. This solution allows individual MU contacts to be forced for trip testing, but only when the MU is in Test Mode. This solution provides a streamlined method for the manual operation of an individual breaker under maintenance or during commissioning, adding an extra layer of protection to prevent inadvertent tripping of the incorrect breaker.

2) Out-of-Service Logic

The utility-developed MU out-of-service (OOS) logic is enabled through a virtual input on the relay. When the MU is taken out of service, the relay removes the associated currents from the active protection elements and disables the corresponding alarms. This provides an easy process for taking a breaker with MUs out of service for maintenance without generating alarms or requiring the relay to be removed from service. The utility also expects this to be useful in the future in the event of BF replacement projects where the breaker includes integrated MUs. Additionally, the MU OOS logic

improves the flexibility of testing DSS relay systems. During testing, rather than requiring active connections to all in-service MUs or a complete mimic setup, duplicate connections can be made to a single MU, or a subset of the required MUs can be connected without changing relay settings (e.g., connecting only one of two high-side breaker MUs on a transformer). The utility anticipates this to be extremely helpful in testing DSS bus, transformer, or three-breaker line applications, where traditionally only two three-phase currents are injected at a time.

3) IEC 61850 Blocked Mode

The IEC 61850 standard contains the concept of Test and Blocked Modes, which the utility chose to implement via a front-panel pushbutton [5]. When a relay is in Blocked Mode, the current states of all output contacts (local and MU contacts) are frozen [6]. Because Blocked Mode is implemented at the relay level, if an MU shares connections with other relays, only the signals from the unit in Blocked Mode are affected.

In the current utility implementation, Blocked Mode generates a front-panel indication of Relay in Blocked Mode, asserts an abnormal system condition alarm, and generates a Sequence of Events log due to the importance of understanding when a device is in an abnormal operating state like Blocked Mode.

Within the selected manufacturer device, entering any control mode other than On (i.e., normal operation) will cause the front-panel-enabled LED to flash as an additional indication.

In addition, within the utility-selected devices, Blocked Mode does not prevent the relay logic from evaluating analog or digital inputs or updating relay element and output logic. Therefore, the active state of a device can be evaluated before it is removed from the blocked-mode state (i.e., confirm the device is not actively issuing a trip and close signal).

In general, Blocked Mode provides a simple and effective method of virtually isolating an entire relay. It can be used for a variety of applications, including settings changes, firmware updates, and other maintenance activities, while simplifying the isolation process.

D. Relay Validation

In conventional systems, test switches are often used to isolate relays from copper CT and PT circuits, and to allow a secondary injection test set to be connected to the relay through the insertion of a test paddle into the test switch. The test sets are used to run multiple test plans to simulate various fault and system conditions, and the relay responses are recorded and validated.

It is possible to leverage the same workflow with a DSS, but the test switches are now distributed throughout the substation yard in various equipment and MU cabinets. This makes secondary injection testing more complex and may require multiple test sets that are synchronized to a common time source simply due to the location of the MUs.

Alternatively, the utility has developed a test procedure using an in-house-designed MU test box. The test box houses two MUs and breaks out all fiber ports, analog inputs, and

digital I/O to test jacks, facilitating easy reconfiguration for testing in the field.

A concept drawing of the MU test box is shown in Fig. 12. In practice, this test box will be used within the control house to replicate the MU connections expected from the field (a maximum of eight connections).

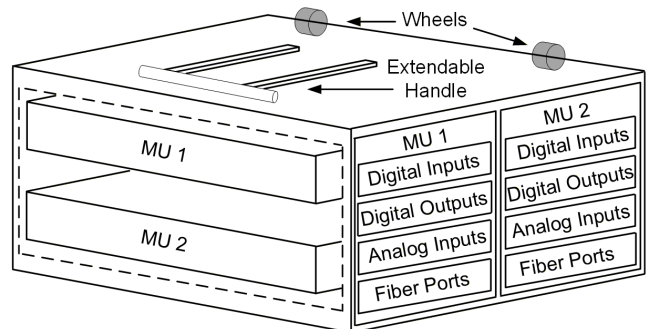


Fig. 12 Utility MU Test Box Concept

Based on current field experience, the utility designed two variants of this test box, each containing a different combination of MU types. One variant, which is designed for line and BR applications, includes two units with four current inputs and four voltage inputs, and the other variant, which is designed for transformer and bus relay applications, includes one unit with four current inputs and four voltage inputs and a second unit with eight current inputs [7]. The primary goal of these test boxes is to facilitate element testing of DSS relays without requiring changes to in-service settings (i.e., no digital remapping). Although in some cases, such as transformer or bus differential applications requiring numerous MU connections and associated currents, the utility MU OOS logic will likely be required to limit testing to only simulating two breakers at a time to align with standard test practices.

During commissioning, in-service fiber connections will be removed and connected to the test box, simulating the exact number of in-service connections expected by the relay. A specialized command will then be issued to the relay causing it to commission and accept the connected test box MUs, regardless of the type or duplicate connections.

Once this is complete, a secondary injection test set can then be connected to the test box using the same methods as injecting into test paddles, and the same standard test plans can be run for relay element and setting validation, as shown in Fig. 13.

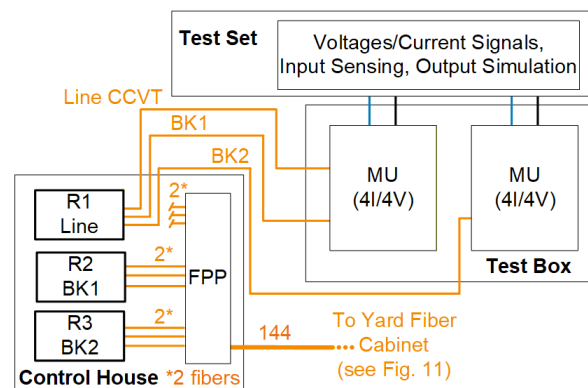


Fig. 13 Relay Testing in a Control House Using a Test Box

E. MU and In-Service Fiber Testing

Once the relay settings and operation have been fully evaluated in the control house and the in-service fiber connections are restored, the MU hardware, fiber health, and fiber connectivity must still be validated. The utility has developed the following process based on field experience.

The first step of this process is conducted inside the control house. A command is issued to the relay to validate the real-time status of each connected MU, including the MU type, serial number, connection health, and transmit (TX) and receive (RX) signal strength measured by the local fiber port. If any issues are detected during this process, an error report will be generated. If there are no issues, the relay then undergoes digital commissioning, which resends the MU digital mapping and allows the relay to automatically validate the MU type and connection health, as well as enable data exchange with the in-service MUs.

Next, a secondary injection test set is moved into the substation yard, MU test switches are opened, and basic stepped-metering injection is performed on each test switch using a test paddle. This step verifies that the relay meters the correct quantities (magnitudes and phase angles) on the correct inputs. This step is then repeated with the CT and PT circuit test switches closed by establishing connections at the primary equipment secondary terminal blocks. The purpose of repeating this step with a different injection point is to validate the copper secondary wiring between the secondary terminal blocks of the equipment and the MUs. This process is represented in Fig. 14 and is repeated for all MUs.

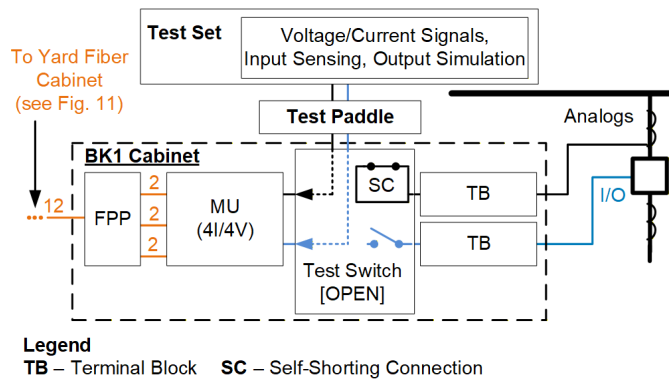


Fig. 14 MU and In-Service Fiber Validation

F. MU I/O and Breaker Operation/Alarm Test

The utility has a historic practice of validating BR I/O through manual operation of the breaker via the trip, retrip, and close outputs. Breaker alarm conditions are simulated using real breaker mechanisms to exercise the breaker alarm contacts. These checks serve to fully exercise and validate the relay I/O, dc circuitry, breaker circuitry and mechanisms, and supervisory control and data acquisition (SCADA) alarm points.

The utility maintained this process in their current implementation of DSS. The only notable differences are that the physical relay I/O is replaced with MU I/O in the test procedures, and the relay-to-MU fiber connections are effectively retested.

At this time, the DSS relay system has been fully tested to the same validation level as conventional systems, with relay elements, digital mapping, secondary connections (fiber links, secondary copper cabling), analog-to-digital (A/D) conversion, the dc system, digital outputs, dc cabling, trip and close coils, breaker and transformer alarms, and digital inputs all functioning as designed.

For a more detailed description of how the utility combines all the commissioning and testing features described in Section VI, refer to the Appendix.

G. Relay Maintenance

DSSs using P2P MUs introduce changes to the maintenance and verification of current- and voltage-sensing circuits. Rather than relying solely on verification of copper secondary circuits and relay A/D checks, DSS includes fiber-optic communications channels and MUs as integral portions of the measurement path.

To support reliable operation of these digital measurement paths, the utility plans to leverage the self-monitoring capabilities inherent in modern relays. Communications channel health is continuously supervised through optical transceiver diagnostics and validates communications integrity. Abnormal conditions generate alarms when signal levels, communications loss, or other device failures fall outside the acceptable ranges established by the equipment manufacturer. This monitoring provides continuous awareness of communications path health and enables corrective action. The approach is intended to support operational reliability and is not currently relied upon for NERC Protection and Control (PRC) 005-7 maintenance compliance.

In addition to periodic maintenance and testing, the utility has developed and deployed asset health monitoring techniques [8] designed to identify abnormal instrument-transformer behavior before it results in equipment failure or relay misoperation. These methods compare remeasurements from redundant protection systems using either synchrophasors and centralized analytics or IEC 61850 GOOSE messaging with analytics in one of the protection systems. Detection of unexpected magnitude or angle deviations could indicate transformer degradation, secondary circuit abnormalities, or relay measurement issues.

While these monitoring capabilities provide valuable operational information regarding instrument-transformer condition, the utility does not currently rely upon these methods to satisfy the continuous monitoring provisions of NERC PRC-005-7 for current- and voltage-sensing devices. Rather, the monitoring function provides situational awareness and transmits alarms to SCADA for proactive maintenance on the protection system.

Trip-control circuitry maintenance similarly evolves in DSS applications. Traditional verification of relay outputs, trip wiring, auxiliary relays, and breaker trip coils remain necessary; however, maintenance must now verify the MUs. The utility is evaluating additional methods to simplify and automate the verification of protection system trip paths [9]. One concept under consideration is the use of SCADA to

actuate individual breaker trip coils from the control system. Such an approach could provide a means to periodically verify portions of the end-to-end trip path, including relay outputs, MU interfaces, control circuits, and the breaker trip coils, while producing documented evidence of successful operations. This concept remains under evaluation, and no programmatic deployment has been implemented at this time.

VII. ROADMAP

The near-term utility roadmap focuses on the completion of the initial DSS standards for each P&C application up to 138 kV. A pilot project has been identified for each standard to work through commissioning challenges and incorporate lessons learned into the standard before final release. Pilot projects for transmission bus, transmission line, and transmission breaker control have already been completed, and pilot projects for distribution CPC and transmission transformer applications have been designed and are awaiting construction.

Following the completion of the initial DSS standards and pilot projects, the utility will focus on expanding the use of the DSS standards and training field and engineering personnel on the new designs. The utility expects that further deployment of the DSS standards will continue to refine and mature the standard designs and testing and commissioning procedures. In parallel, the utility plans to pursue stronger manufacturer integration to reduce the number of MU cabinets and increase options for equipment with built-in MUs.

The next step in the journey beyond DSS for the utility is to evaluate and pilot the use of station buses for relay-to-relay signals within the control house. The utility already leverages station bus technology for noncritical data exchange between protection relays on the substation local area network. However, it has historically avoided relying on the network for critical protection signals such as trip, lockout, and BF initiate. The utility plans to evaluate this approach through structured lab tests with the goal of further reducing panel and control house wiring while improving panel manufacturing and project execution speed.

The long-term vision of the utility is to continue to develop, implement, and refine DSS solutions with a focus on consolidating P&C functionality. The distribution CPC design will continue to be refined, and experience gained from this solution will be leveraged to evaluate consolidated solutions at the transmission level. Current offerings in the market for transmission CPC solutions rely on virtualization technology and IEC 61850-9-2 (or IEC 61869-9) SV data streams; however, the utility plans to partner with manufacturers to develop and evaluate future transmission CPC solutions.

VIII. CONCLUSION

The transition to DSSs represents a significant evolution in the way P&C systems are designed, commissioned, operated, and maintained. For practical experience in designing and transitioning to DSSs, the experience of the utility demonstrates that the DSS approach is not simply a replacement for copper conductors with fiber-optic cables but a broader shift towards simplified field installations, improved monitoring, and more

flexible P&C architectures. The selected P2P DSS approach preserves many familiar protection philosophies while reducing network complexity, eliminating the need for external time synchronization, and limiting exposure to networked communications paths. This alignment with existing utility practices has allowed the utility to take incremental, practical steps towards DSS adoption while maintaining the redundancy, reliability, and operational discipline required for protection systems.

The early DSS deployments of the utility have shown that successful implementation requires more strategizing than simply selecting the appropriate relay and MU technology. Standard drawings, relay settings, testing tools, commissioning procedures, vendor integration, cybersecurity interpretations, and maintenance expectations must all evolve together. Lessons learned from greenfield, brownfield, and hybrid projects have helped identify where DSS can simplify designs and where it introduces new engineering, operational, and testing considerations. In particular, the movement of I/O and CT and PT interfaces from the control-house relays to the yard MUs requires functional drawings, fiber documentation, remote I/O mapping, test modes, and end-to-end validation of measurement and trip paths. The utility roadmap is intentionally progressive. The near-term focus is to complete and mature DSS standards through pilot projects, expand training for engineering and field personnel, and continue to refine testing and commissioning practices. In the longer term, the utility plans to evaluate additional DSS capabilities, including reduced yard cabinet requirements, station bus applications for relay-to-relay signals, and future consolidated P&C architectures. These efforts support the broader objective of delivering P&C systems that are scalable, maintainable, reliable, and cost effective while helping the utility meet the increasing infrastructure demands. The experience gained to date indicates that DSS can become a foundational technology for future substation designs when it is implemented through careful standardization, practiced testing methods, strong manufacturer partnerships, and a clear understanding that digital architectures change the life cycle of P&C systems.

IX. APPENDIX

The utility has consolidated the topics discussed within the Testing, Commissioning, and Maintenance section of this paper into the following standardized commissioning procedure for the deployment of future DSSs. This is being shared with the hope that it may provide a starting point for other organizations adopting DSS technology.

A. Precommissioning Assumptions

Notably, this procedure includes the following precommissioning assumptions:

1. DICM and primary equipment (breakers, transformers, CCVT cabinets) are delivered to the site with integrated relays and MUs prewired and wire-checked at the factory. This includes preterminated fiber jumpers between the relay and DICM patch panel, as well as between the MU and remote patch panel. Ideally, relay

and MU analog inputs, digital inputs, and digital outputs have been tested for proper operation prior to arriving onsite.

2. The telecommunications team has already terminated, labeled, and tested fiber-optic connections between the DICM patch panel and primary equipment patch panels.

In the future, the substation field services team plans to enhance their knowledge and experience with fiber-optic communications links such that they can effectively install and troubleshoot DSSs. The utility believes this will become increasingly important as DSSs continue to be deployed throughout the system.

B. Standardized Commissioning Process for Future DSS Deployment

1) Validate Equipment Power and MUs

Inspect the DICM and primary equipment cabinets for healthy dc power and enabled lights, and log unique MU serial numbers based on equipment location.

2) Configure the Relays

Obtain as-issued relay settings and send them to the relays to establish the expected field assignments of MU connections, digital mapping of analogs, and I/O operation. (The step requiring the relays to validate that MUs are physically connected and meet all intelligent self-checks for expected type [i.e., four CT and four PT connections versus eight CT connections] and connection health is intentionally omitted at this time.)

3) Isolate the Relay From In-Service Connections

Temporarily remove in-service fiber connections from the back of the relay.

4) Connect the MU Test Box to the Relay for Settings Validation

Use the MU test box to mimic expected in-service MU connections to the relay. Due to traditional relay test plans using only one or two sets of three-phase current (or voltage) injection at a time, test all protection elements in the relay through a combination of protection element disabling and various test-set-to-relay port connections. Issue a specialized test commissioning command to the relay bypassing smart checks for proper MU type, allowing additional flexibility for relay testing using a common test box.

5) Validate Relay Settings Through Secondary Injection

Connect a secondary injection test set to the test box with the same methodology as a conventional relay, and execute traditional test plans. Note that minor deviations may be required, including monitoring both MU signals and interrelay signals, such as BF initiate.

6) Restore In-Service Fiber Connections

Disconnect the test box from the relay, and restore the in-service fiber connections.

7) Validate Fiber Connections and Health

Issue an MU status command to the relay to obtain diagnostic information on the real-time MU connections,

including MU type, serial number, and relay fiber-port TX and RX signal strength. Use the field notes taken in Section IX.B.1. (i.e., Step 1) to validate proper MU-to-port connections based on serial number. Log TX and RX values as a link-budget baseline, and compare them to system specifications.

8) Digitally Commission the Relays

Resend the in-service digital mapping settings to the relays, and use the MU manufacturer software to commission the relay-to-MU connections. During the commissioning process, the relays validate the MU type, learn and lock the connected serial numbers, check for acceptable system health, and enable the relay processing of connected analogs and digital I/O. This process results in the generation of a commissioning report for select relays that can be reviewed and stored as a commissioning record.

9) Validate MU A/D Health, Fiber, and Port Connections

Perform a secondary injection into the MU test switches in the yard, and verify the metering quantities on the relay (correctly observed current and voltage signal, correct magnitude, correct phase angle). Repeat this process for all CT and PT circuits, but move the secondary injection point from the test switch to the primary equipment secondary terminal blocks to validate the copper secondary wiring. Repeat this process for all MUs.

10) Validate MU Inputs and Breaker Coils

Perform a manual trip (Trip Coil 1 validation), a retrip (Trip Coil 2 validation; manual trip with Trip Coil 1 opened), and a close (close coil validation). This process validates that all in-use MU outputs, dc circuitry, and breaker elements are working as intended. This also validates the 52a breaker-status MU input.

11) MU Input Validation

Simulate breaker alarm conditions using real breaker mechanisms, and validate alarms at both the relay and the SCADA. This step validates all in-use digital inputs on the breaker.

This concludes the current utility commissioning plan for DSSs, offering a comprehensive yet streamlined process for primary equipment, MU, relay, secondary wiring, and fiber connection validation.

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XI. BIOGRAPHIES

Daniel Musci received his BS in electrical engineering from Ohio Northern University in 2019. He joined American Electric Power (AEP) in 2019 as a protection and control engineer. He currently serves as a principal engineer in the Transmission Protection and Control Standards department at AEP. He is a registered professional engineer (PE) in Ohio.

Jason Byerly is a consulting engineer at American Electric Power (AEP). He joined AEP in 2004 and has held several roles in protection and control engineering. He earned a BS from The Ohio State University in 2004 and an MSEE from the University of Idaho in 2026. He is a registered professional engineer in Ohio, a senior member of IEEE, a contributor to the IEEE Power System Relaying and Control Committee, and a member of the IEC 61850 working group.

Manish Thakur is the managing director of transmission engineering at American Electrical Power (AEP), bringing 30 years of experience in protection and control (P&C). His current responsibilities at AEP include transmission and distribution standards—including P&C—enterprise-wide compliance, and transmission relay misoperation investigations for systems up to 765 kV. Manish’s areas of expertise include high-impedance fault detection, line protection, reactive power compensation applications on extra-high voltage systems, transient and real-time simulations, NERC PRC-027, and digital secondary system technologies. Prior to joining AEP, Manish worked with ABB and General Electric as a P&C application and consulting engineer. He earned his Bachelor of Science in India and his Master of Science from the University of Manitoba, Canada. Manish is a member of IEEE and a licensed professional engineer (PE) in the state of Ohio.

Andrew Dulmage received his BS in electrical and computer engineering from The Ohio State University in 2009. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2009, where he works as a senior automation application engineer in the Sales and Customer Service division. Andrew is a senior member of IEEE.

Bryan Seyfert received his BS in electrical engineering with a concentration in power systems from the University of Pittsburgh in 2018. He joined Duquesne Light Company in 2019 where he was a protection engineer working in both transmission and distribution. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2024, where he works as a project engineer in protection. Bryan is a member of IEEE.

Chris Burger received his Bachelor of Science degree in electrical engineering from Virginia Polytechnic Institute and State University in 2015 and his Master of Engineering in electrical engineering from the University of Idaho in 2022. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2015, where he works as a senior protection application engineer in the Sales and Customer Service division. Chris also obtained his PE certification in the state of Ohio in 2021.

Syed Aarsal Hussain received a BTech degree in electrical and electronics engineering from the National Institute of Technology Karnataka, India, in 2018, and an MS degree in electrical power systems engineering from North Carolina State University in 2019. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2020, where he is currently a project engineer in automation within the SEL Engineering Services, Inc. (SEL ES) division.