Practical Considerations, Best Practices, and Lessons Learned From Large Utility Station Upgrade Projects

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***Abstract*—Growth in renewable energy is, in many cases, driving the need to upgrade and reconfigure aging existing power system substations. In one such application, a new 13 terminal breaker-and-a-half substation was built to replace an existing substation about a half mile away that had ties to a generation plant. A creative new technology solution using a digital secondary system (DSS) was chosen for the protection of five tie lines in this application. DSS was used to protect the entire zone from the new station breakers to the neutral current transformers (CTs) on the generator, allowing the short line, unit transformer, and generator to be covered by dual differential protection. Cost savings and schedule efficiency improvements were realized using this and other such practical considerations.**

The purpose of this paper is to discuss the best practices and solutions applied on the project, such as developing stage-wise construction sequence documents, implementing a temporary wind farm line configuration to overcome supply chain challenges, applying creative protection and control solutions with DSSs, and repurposing multiple relays during different construction stages of the new substation for operational efficiency. The paper also documents best practices involved in considerations for using bypass switches on breakers, protecting generator-to-utility tie lines, and designing breaker failure protection for generator unit breakers. A caution on using motor-operated disconnect switch auxiliary contacts in protection and control trip and close logic schemes is discussed.

I. Introduction

Fig. 1 and Fig. 2 show a before-and-after simplified one-line diagram of one of several switch station upgrade projects executed in the Western Farmers Electric Cooperative (referred to as “the co-op” throughout this paper) system. The existing 138 kV main-and-transfer bus arrangement station (Fig. 1) was upgraded to a breaker-and-a-half substation arrangement (Fig. 2). The new switch station was built 0.5 miles from the existing switch station. The existing switch station also includes a generation plant. (A complete existing and new station simplified overall one-line diagram is shown in the Appendix, Fig. 29 for reference). The main goal of this paper is to share practical considerations, best practices, and lessons learned from such large utility station upgrade projects.

The paper concentrates on the multiyear project to upgrade a transmission switching station in the South Central region of the U.S. The project is a good representative of the co-op’s recent upgrade projects. Experience from the other projects is included.

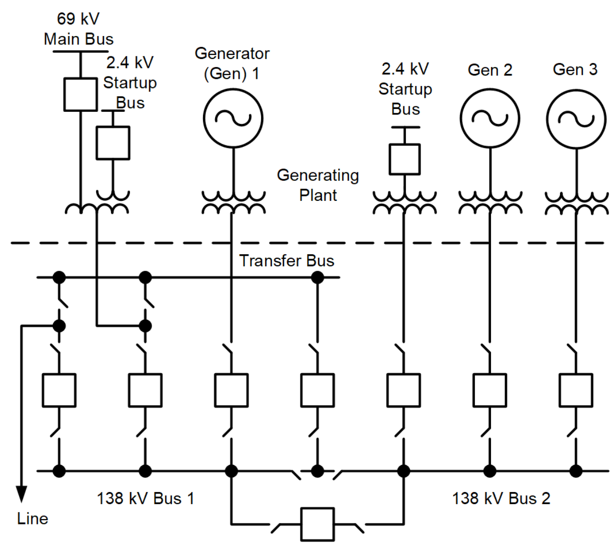

Fig. 1. Partial simplified one-line diagram of the existing switch station. One of seven lines shown.

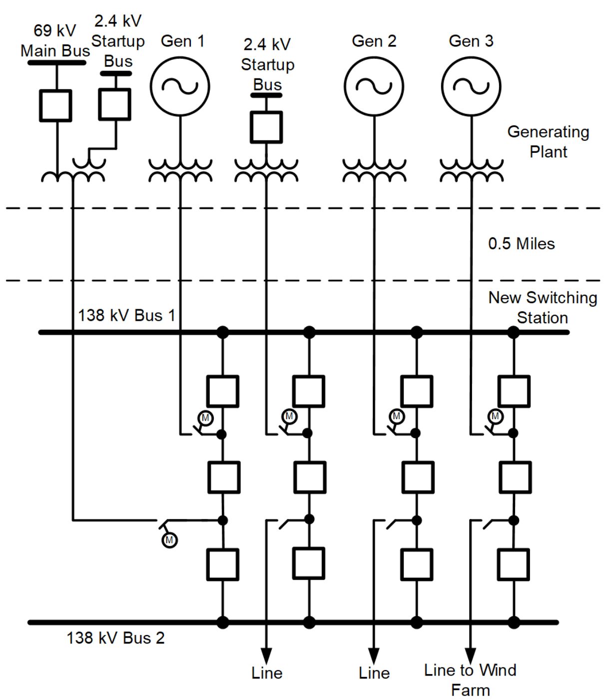

Fig. 2. Partial simplified overall one-line diagram with new 138 kV switch station (only four of seven bays shown).

The core goal of this project was the interconnection of a new wind farm to the new 138 kV transmission switch station. The existing station was a 12 breaker main-and-transfer bus station with multiple 138 kV line connections, including two interconnections with another utility but no new bays to accept a new transmission line connection. Additionally, much of the equipment at the existing station had reached life expectancy, was deteriorating due to age, and was close to being overdutied for the state of the system. This problem would be exacerbated by the interconnection of the new wind farm. The decision was made to rebuild the 138 kV station at a new nearby location and migrate all the transmission line and generator connections to the new station.

In addition to the interconnection of the wind farm, the co-op's goals for the project were as follows:

- Improve safety by installing modern equipment, new grounding grids, and circuit breakers that were not overdutied.
- Improve reliability, operation, and maintenance flexibility by upgrading to a more robust bus configuration.
- Demolish the existing outdated protective relay devices in favor of modern digital relays with more advanced features.
- Remove outdated and confusing protection schemes, such as the main-and-transfer bus-tie breaker scheme, that were no longer suitable for use on the system.
- Update the station controls to the co-op standard format that is far more familiar to the technicians.
- Create new, high-quality drawing sets for the new station that would be far superior to the decades-old and often unreliable existing station drawings.

The project involved both greenfield and brownfield design. Since the existing switch station had single breaker topology with main-and-transfer buses, the existing generator plant protection design and relay settings had to be modified to incorporate dual breaker topology for the new switch station.

The project scope involved providing a turnkey solution including substation engineering; procuring a control house, panels, and secondary equipment; protection and control (P&C) engineering and the development of relay settings; and onsite installation, demolition, and commissioning support.

As is typical of such projects, it was not possible to take a full station outage to transfer the circuits to the new station; hence, the project was implemented in a staged construction sequence. The goal was to transfer the circuits, with no or minimal disruption to existing load and generation, with planned minimum circuit outages, all while maintaining the highest safety and quality standards. The transmission line construction, energization, and commissioning were executed in ten main construction sequence stages. Design drawings, fault studies, relay settings, and commissioning plans were developed for each stage. For some stages, protection schemes were repurposed to significantly save time and expenses.

II. Construction Sequence

A critical element in the success of this complex project was the development and use of a construction/outage sequence document. The main purpose of this document was to ensure all departments were aligned with respect to the scope, execution, and safety needs for each stage. A concise one-page document per stage proved invaluable, outlining the detailed schedule and steps for each phase, with a particular focus on outages or periods when parts of the substation terminal(s) and associated equipment were offline. The Appendix includes Fig. 29, Fig. 30, Fig. 31, Fig. 32, Fig. 33, which show Stages 0A, 0B, 1, 4, and the final construction sequence configurations, respectively, for reference. These stages are discussed in more detail later in this section. Despite its compact format, each phase was meticulously detailed, as follows:

- Stage number
- Detailed station one-line representation of existing and new station
- Stage name (e.g., transmission line or generator terminals to be moved)
- Construction duration
- Outage duration
- Scope of work
  - A brief description of the work to be performed in that stage
  - Engineering scope
  - Construction scope
  - Testing/commissioning scope
- Points of isolation
  - List of breakers and switches to be opened
  - Terminals to be de-energized
- Points of energization: terminals, breakers, and switches to be energized upon completion of the stage

This document remained dynamic, evolving as the project progressed. For example, while the initial functional design specification outlined ten stages, five intermediate stages were added to align with operation flexibility, improving schedule efficiency while minimizing outage requirements. This flexibility was made possible because the document offered a comprehensive view of the entire project, enabling adjustments while maintaining a clear overall perspective on high quality and safety.

A. *Stakeholder Contributions*

The construction and outage sequence for the switch station project required extensive collaboration between multiple contributors to ensure seamless execution while maintaining system reliability and stability. Key stakeholders included more than ten internal and external teams comprising the co-op Planning Department, P&C Engineering, Substation Physical Engineering, Transmission Line Design Engineering, Project Management, Construction, and Operations teams. Each played a critical role in addressing specific technical and operational considerations.

1. Operations Department
  - Objective: Ensure system reliability and continuity of service with minimal operational disruption.
  - Focus areas:
    - Minimizing outages during construction
    - Implementing temporary load transfers to maintain grid stability and operational performance
2. P&C Engineering
  - Objective: Maintain effective system protection during phased construction while minimizing costs, reducing potential for undesired operation, and improving safety.
  - Focus areas:
    - Utilizing existing protection relays for temporary tie interconnections to improve efficiency and realize cost savings.
    - Designing protection schemes to ensure system safety and reliability throughout project transitional stages.
3. Substation Physical Engineering
  - Objective: Maximize system reliability through optimized physical layout and terminal placement.
  - Focus areas:
    - Methodically placing terminals on breaker-and-a-half station bays (sometimes referred to as rungs) to avoid generator sources being located on the same rung and simplifying construction.
    - Implementing designs that improve reliability and facilitate ease of maintenance.
4. Transmission Line Engineering
  - Objective: Simplify design and optimize cost while ensuring structural and electrical performance.
  - Focus areas:
    - Avoiding transmission line crossings whenever possible to reduce design complexity.
    - Reusing existing structures where feasible to manage costs effectively.
5. Construction Team
  - Objective: Ensure the feasibility and practicality of all terminations and phased construction activities.
  - Focus areas:
    - Verifying design constructability during execution.
    - Coordinating construction timelines to align with system outage schedules and maintenance windows.

B. Construction Sequence Overview

1) Stage 0: Construction of the New Switch Station and Temporary Wind Farm Line

Stage 0 (later renamed to 0B) involved constructing and testing the new 138 kV breaker-and-a-half switch station. This included 20 breakers and associated station equipment installed in 7 breaker-and-a-half station bays (rungs). The station was built about 0.5 miles away from the existing substation. This new substation build would require no outages or system interruptions. A drop-in control house module with 18 panels was installed in the new switch station as part of this stage. Full functional factory acceptance testing (FAT) of the control house and panel internal P&C design was performed at the factory, prior to shipment.

This stage also included full final stage functional testing of all field wiring to the control house and the relay settings. All relays were tested for full functionality, as far as possible, with any end-to-end testing remaining for individual stages. The goal was to minimize outage time requirements during each stage.

As discussed before, one of the main goals of the project was to tie in a wind farm line to the new station. The goal was to accomplish this by a date that was critical to the wind farm owner and the co-op. There were liquidated damages tied to the interconnect agreement. Due to the COVID pandemic and subsequent supply chain disruptions, the interconnection date to the new station appeared to be at risk. As a result, the team had to consider alternative solutions, leading to the development of a temporary configuration solution that was included as Stage 0A in the construction sequence. A simplified before-and-after version of the solution is shown in Fig. 3. Details of construction sequence Stage 0A are shown in Fig. 29 for reference.

As shown on the left side of Fig. 3, Before Stage 0A, the construction of the new wind farm line was completed up to the last pole before the new station. As part of Stage 0A, Line 1 was split into two sections. A temporary jumper was utilized to connect the wind farm line to the Line 1 section going to the existing station. This formed a two-terminal line from the wind farm to the existing station Line 1 terminal position (as shown on the right side of Fig. 3, After Stage 0A). Another temporary jumper was installed between the second Line 1 section (going to a remote terminal) and Line 2, to form a three-terminal line. This freed up the existing substation Line 1 terminal position for the temporary interconnection of the new wind farm line. Fig. 30 of Stage 0B shows (on the top upper left) the wind farm line connection and the adjacent three-terminal line connection. During the temporary configuration, the wind farm generation had to be limited to 143 MVA to avoid exceeding the 600 A continuous ampacity rating of the disconnect switches in the existing switch station.

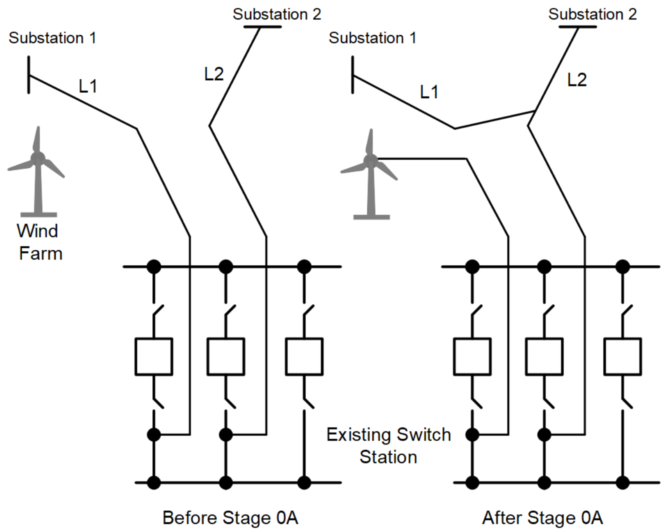

Fig. 3. Stage 0A temporary wind farm line.

From a protection configuration viewpoint, the new wind farm line along with the Optical Pilot Ground Wire (OPGW) fiber connections for dual line differential protection was to be built to the new station. This OPGW was not available for this temporary stage configuration to the existing substation. The team worked around this challenge by utilizing line relays with instantaneous overreaching step distance zones covering the line and part of wind farm end transformer with a direct transfer trip (DTT) sent via serial radio communications to the wind farm. These radios were later repurposed and utilized in subsequent stages for efficiency gain. The team also installed temporary metering equipment, including current transformers (CTs), voltage transformers, and meters, as required per the wind farm agreement.

The three-terminal line was protected using a permissive overreaching transfer trip pilot scheme using existing communications channels. The electromechanical relays at the existing switch station were upgraded to microprocessor relays. Drawings and relay settings were developed in Stage 0A for implementing the temporary line configuration.

2) Stage 1: Relocation of Two Line Terminals

Fig. 4 shows the simplified Stage 1 construction sequence configuration. Full details of construction sequence Stage 1 are shown in the Appendix, Fig. 31, for reference. Two terminals (L5 and L6) were prioritized for relocation in this stage. These two terminals were in close proximity to the new switch station and existing line routes, simplifying construction logistics. These two terminals were placed in the two southernmost positions (on Bays 6 and 7) of the new switch station to

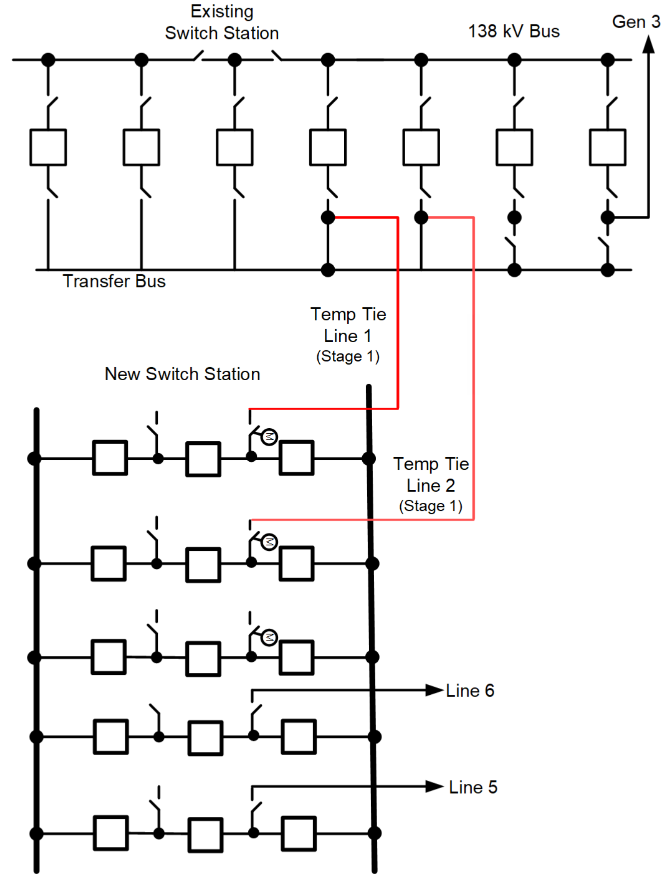

Fig. 4. Relocation of Lines 5 and 6. Temporary tie line between existing switch station and new switch station (not all lines and generators are shown).

minimize transmission line crossings and design complexities. As part of this first stage of transferring line terminals, it was important to connect the two substations electrically. The team designed temporary tie lines connecting the new switch station to the existing switch station to maintain system stability and uninterrupted load flow. These tie lines were later repurposed in subsequent stages for ties to generator terminals, gaining cost and schedule efficiency.

3) Subsequent Stages (Stage 2–Stage 10)

Fig. 32 shows the Stage 4 construction sequence diagram for reference, as terminals were moved from the existing to the new station. The team planned to sequentially fill positions at the new switchyard from south to north to streamline construction. Outage windows were aligned with predetermined maintenance schedules of the plant, planned months in advance.

Fig. 33 shows the final configuration with all terminals moved and the existing switching station ready for demolition.

By integrating detailed technical planning, stakeholder collaboration, and phased execution, the project achieved its objectives while maintaining system reliability, optimizing costs, preventing undesired operations, and preparing for future system growth.

III. Applying a Digital Secondary System (DSS) to Protect Utility-Generation Tie Lines

The new 138 kV switch station (Fig. 2) includes five utility-to-generation tie lines that tie into three, unit-connected, gas generator, main step-up transformers, one startup transformer, and one tie transformer.

The co-op typical standard protection for short transmission tie lines includes dual independent, line differential protection systems. Each system has a relay at each line terminal that provides tripping and control for that terminal. Each system has a communications channel independent from the other system that communicates measured currents and digital signals between the relays, often over optical fibers. Each relay is connected to dedicated CTs, if available. If one line terminal is a unit-connected generator step-up (GSU) transformer, the relays measuring currents at the GSU transformer provide plant trips for line faults or transfer trip signals from the switch station.

Each transformer shown in Fig. 2 has only one set of CTs on the high side of the transformer. These CTs were used for existing transformer differential protection with modern digital relays that were to be kept throughout and at the conclusion of the project. To apply the co-op standard dual redundant line differential protection for the short tie lines with acceptable isolation and simplicity between all protection systems, new 138 kV transformer bushing CTs or free-standing CTs would be needed for all five transformers. Considering there are 5 tie lines between the gas generating plant and the new switch station, a total of 15 CTs had to be installed to implement the line differential protection. This presented an opportunity for significant cost, schedule, and efficiency savings, if the need for adding these additional 138 kV CTs could be eliminated. The use of a DSS by forming an overall zone of protection from the generator neutral CTs to the newly built switch station transmission breaker CTs was considered. The DSS solution, featuring time-domain-link enabled differential relays, was chosen for protecting the utility-to-generator tie lines. With independent, dual DSSs, this novel approach provided dual redundant tie line protection, fiber communications paths for the exchange of trip and control signals between the plant and new switch station, and an additional layer of redundancy to both generator and GSU transformer protection. The DSS solution implemented to protect the five tie lines resulted in project cost savings and improved efficiency, while maintaining desired operational flexibility. The adaptability of the DSS solution to protect short transmission lines with different terminations throughout the project stages proved to be beneficial and is discussed later.

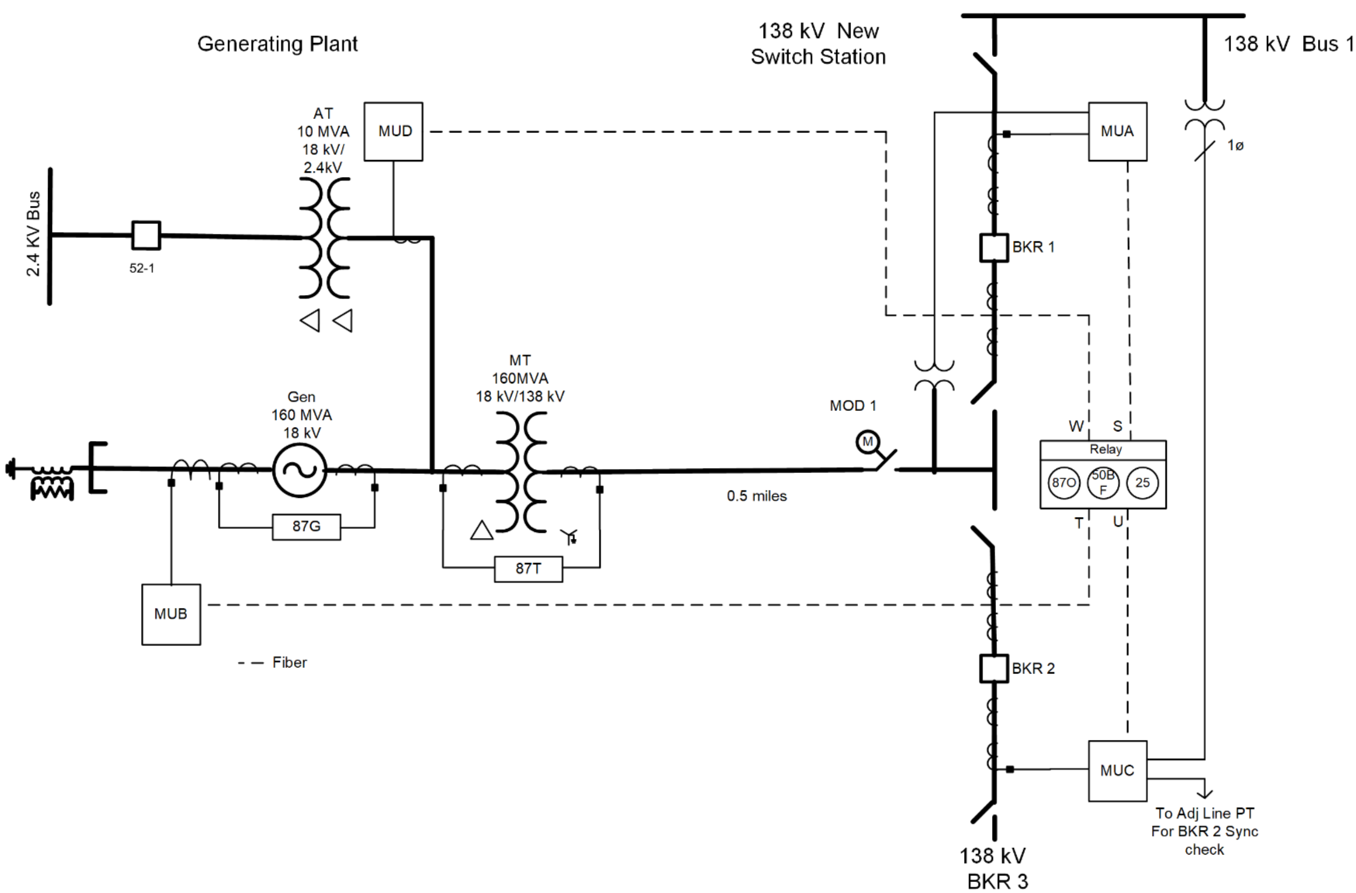

Fig. 5. Simplified protection one-line diagram for DSS tie-line application.

A simplified protection single-line diagram for one DSS in this application is shown in Fig. 5. Two merging units, MUB and MUD, are in the plant connected to the generator neutral-side CTs and the auxiliary transformer high-side CTs, respectively. Two merging units, MUA and MUC, are in the new switch station and connected to the 138 kV breaker CTs. The merging units are connected to the relay with optical fibers. For this application, the merging units are installed inside the control house at the new switch station and inside the retrofitted existing panels on the plant side to ensure the scheme complies closely with the co-op design standards. Two completely independent DSSs with separate merging units and separate fiber paths are included to provide redundant protection for the tie lines. Redundancy in CTs was maintained and improved as far as practically possible.

A. Zones of Protection

For the tie lines with generators, the overall differential zone (87O) protects the generator, GSU transformer, and short transmission line between the GSU transformer and the switch station. Existing plant protection includes dual differential protection (87G) for the generators. The GSU transformers have dedicated transformer differential protection (87T), which is retained for additional sensitivity. For the tie line with autotransformer, 87O protects the transformer and the short tie transmission line. For the tie line with startup transformer, the 87O only covers the short tie line. The startup transformer is covered by existing dual redundant transformer protection. Two time-domain-link enabled transformer differential relays are used for each zone of protection to provide overall differential protection redundancy. The differential relays located at the switch station are also used, per the co-op standard, to provide synchronism check supervision, breaker failure protection, and breaker open and close control.

On the plant side, the relay panels housing the new plant-side merging units with fiber connections and the existing generator and GSU transformer protection relays are located on the second floor of a building. The proximity of the independent fiber-optic paths from the building entry point to the second floor created a concern for a single point of failure, affecting the critical redundancy of protection communications. Out of an abundance of caution, a third relay with a separate open-air radio communications channel was installed at the switch station in a dedicated panel for each tie line to provide backup protection. The backup relay provides distance (21) protection for the tie lines and also transfers and receives protection trip signals between the plant and the switch station. The radio equipment and some distance relays were from Stage 0A, used for temporary wind farm configuration and repurposed for the backup protection scheme in final configuration.

Replacement of the existing generator and GSU transformer protection at the plant was not part of the scope of the project. Logic settings updates related to the change in configuration from single breaker to breaker-and-a-half were implemented as necessary for each tie line.

A distance protection element was not available within the differential relay during the execution of the project. For future projects, the third backup relay could be eliminated by enabling distance protection within the same 87O differential relay.

One of the limitations of using an overall 87O zone in dual breaker terminal applications is the differing protection performance requirements for high-side lead (tie line, in this application) and transformer zones [2]. The version of 87O relays used in the DSS application allowed for custom logic to consider splitting the 87O zone into a separate high-side tie-line zone (using a transformer high-side bushing CT) and a dedicated sensitive 87T zone. Custom logic was not preferred by the end user and, hence, not used. For transformer protection with dual breaker terminal applications, the authors recommend [1] and [2] for best practices and application considerations . As discussed in the reference papers, some newer versions of 87O relays allow for a dedicated 87 element that covers the high-side lead (tie line, in this application) and a separate 87 element dedicated to the sensitive 87T zone. This enhances protection further for such applications. The availability of two high-side transformer bushing CTs allows for desired redundancy options.

B. Fiber Considerations for Redundancy

Fully redundant protection requires separate secondary systems and equipment without a single point of failure. Trip signals must be transferred from the protective relays to the isolating equipment in completely redundant paths. For the DSS solution, it is crucial to have complete redundancy in communications channels, especially since both analogs and digitals are transferred through the communications. Fiber communications channels for System A and System B use two different underground conduits, and they are routed separately through a primary route and a redundant route. Redundant fiber routing between the plant and the switch station is shown in Fig. 6 with at least 10 feet of separation between the two paths. The conduits are routed such that there is a separate entry point for the fiber cables at the new switch station. The existing plant has only one entry point for the fiber cables, and the integrity of the structural wall was questionable. The structural design team recommended against modifications for another entry point at the plant. From the single entry point at the plant up to the second floor where the MU are, each fiber cable was routed through Panduit to provide separation and protection between the two redundant system fiber cables.

It is very important for the critical nature of the dual redundant fiber path to be communicated, planned, and approved by all parties at the early stages of the project.

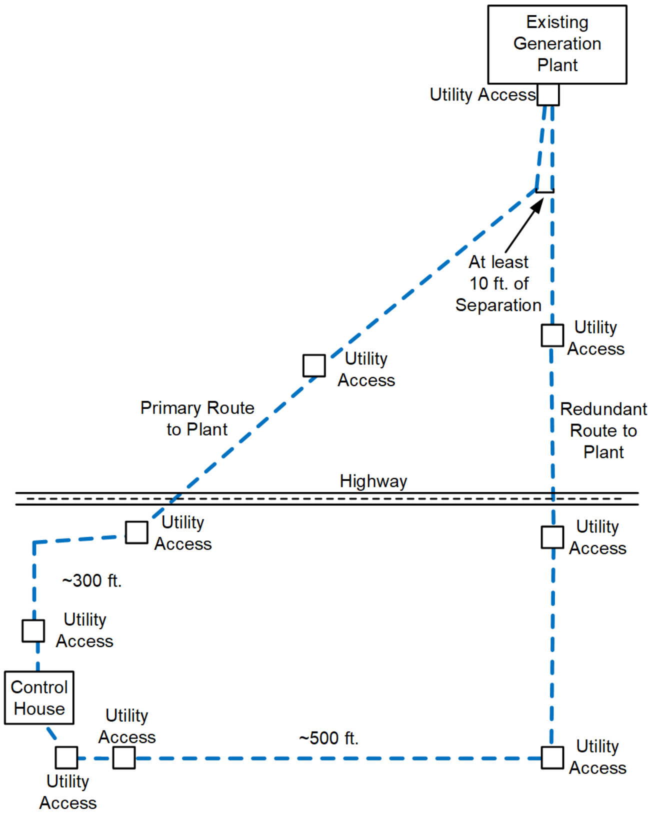

Fig. 6. Fiber routing between plant and station.

C. *Transfer Trips Between Plant and Switch Station*

DSS communications are used to transfer critical digital data, such as breaker statuses, motor-operated disconnect (MOD) switch statuses, protection trips, mechanical trips, close commands, and other control signals between the plant and the new switch station.

1) Trips From Plant to 138 kV Switch Station

The generators are unit-connected with breakers only at the switch station. In the event of a fault, the relays need to trip the necessary plant equipment, which are the generator prime mover, exciter breaker, and transfer plant auxiliary loads. The 138 kV switch station breakers also need to be tripped to isolate the fault.

In the event of a fault detected by the generator relays, GSU transformer relays, or auxiliary transformer relays, the relays trip the lockout relay (LOR) located in the plant, which trips the necessary plant equipment. The LOR trips are also transferred to the switch station to open the 138 kV breakers. Fig. 7 shows a simplified dc schematic and the signals that are transferred from the plant to the switch station for this application, based on the existing design. The plant relay LOR outputs are hardwired to the MUB located in the plant. The MUB inputs are mapped to the protective relay inputs, as indicated in Table I. When the generator differential relay 87G trips or when the plant 86GT LOR is rolled, MUB input IN1 asserts which, in turn, logically asserts the corresponding word bit IN301. IN301 is used in the relay trip logic in Fig. 8 to trip the 138 kV breakers. IN301 also initiates breaker failure logic for the 138 kV breakers that is integrated in the 87O relays.

The following drawings and logic are specific to this retrofit project. Users need to design the scheme based on the existing design and industry standards. For a DSS solution, it is recommended to show the merging unit and the relay input output mapping on the DC schematics for clarity.

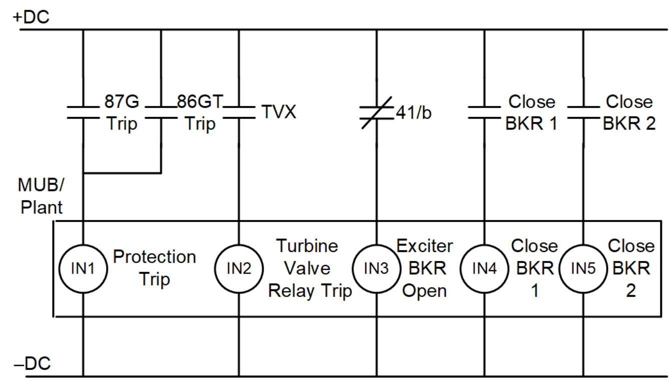

Fig. 7. Simplified dc design for transferring plant signals.

TABLE I
MU–RELAY INPUT MAP

MUB/Plant	Relay 87OA	Function
IN1	IN301	Protection Trip BKR 1 and BKR 2
IN2	IN302	Trip from Prime Mover Relay
IN3	IN303	Exciter Breaker Open Status
IN4	IN304	Manual/Autosync Close BKR 1
IN5	IN305	Manual/Autosync Close BKR 2
IN10	IN310	Manual Trip BKR 1 from Plant
IN11	IN311	Manual Trip BKR 2 from Plant

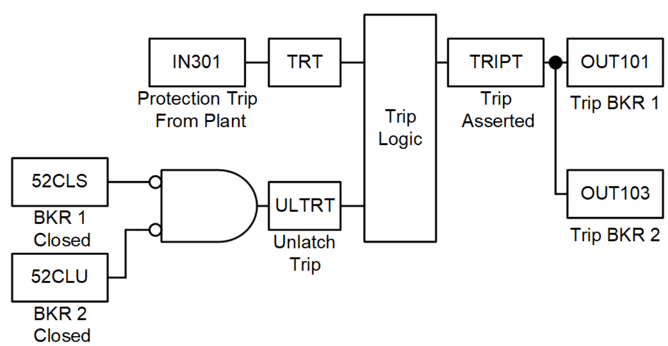

Fig. 8. Protection trip from plant to new switch station.

In the breaker-and-a-half configuration, most often when the generator is taken out of service and disconnected from the system, the switch station generator breakers may be closed for the power to flow between the two main buses. When the generator is disconnected, the MOD 1 switch, shown in Fig. 5, is opened and the 138 kV breakers are closed to complete the rung.

Trips from the plant to the switch station are segregated into protection trips and mechanical trips. The protective relay trips are always enabled, regardless of the MOD status. The generator trips from the turbine stop valve relay (TVX) and the exciter field breaker are replicated from the existing scheme. The mechanical trip from the TVX and the exciter field breaker status are supervised by the MOD status to trip the 138 kV generator breakers. When the generator is offline and the MOD is open, there will be no standing trips from the plant (provided 86GT is in the reset position), and the 138 kV breakers will be allowed to close the breaker-and-a-half rung. Transfer trip logic for mechanical trips is shown in Fig. 9.

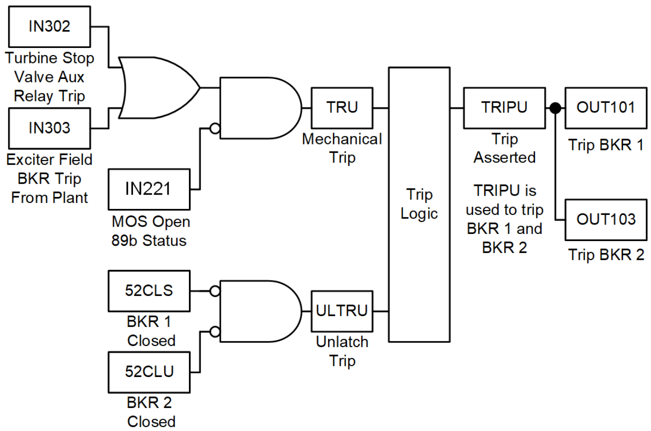

Fig. 9. Mechanical trip from plant to new switch station.

Breaker control switches for each breaker and the MOD are installed in the plant on the relay panels to provide provisions for manual trip from the plant. The plant also has provision to trip the breakers from the distributed control system (DCS). The manual trips from the control switches and DCS are hardwired to MUB inputs IN10 for BKR 1 and IN11 for BKR 2, as indicated in Table I. When a control switch or DCS control initiates a manual trip, MUB input IN10 or IN11 is energized which, in turn, logically asserts the corresponding word bit IN310 or IN311. IN310 is used in the relay logic to trip 138 kV BKR 1, and IN311 is used in the relay logic to trip 138 kV BKR 2. The breakers can be manually opened from the switch station via an 87O relay front-panel pushbutton and by SCADA.

2) Trips From New 138 kV Switch Station to Plant

Logic for transfer trips from the switch station to the plant is shown in Fig. 10 for reference. For a differential trip in the 87O relay, word bits OUT301 and OUT302 are asserted and communicated to MUB in the plant. Upon receiving the digital signals, MUB closes the corresponding mapped outputs OUT01 and OUT02 that are hardwired to the plant LORs that, in turn, trip the plant equipment. See Table II for MUB and 87O relay output mapping. For an in-zone fault, the 87O relays transfer trip to the 86GT LOR and the sudden pressure (63T) LOR in plant. Both 86GT LOR and 63T LOR trip all the plant equipment. In addition, 63T LOR turns off the GSU transformer cooling fans and pumps for transformer faults. The 138 kV breaker failure trips from the switching station are also transferred to the plant to trip 86GT LOR.

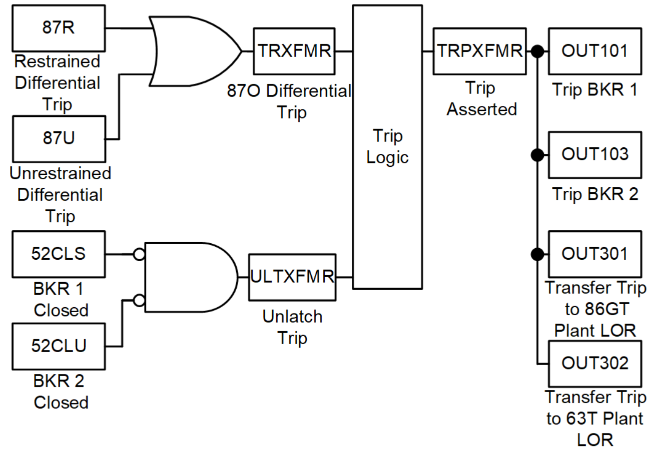

Fig. 10. Transfer trip logic from new switch station to plant.

TABLE II
MU TO RELAY OUTPUT MAP

MUB/Plant	Relay 87OA	Function
OUT01	OUT301	86GT LOR Protection Trip from Switch Station
OUT02	OUT302	63T LOR Protection Trip from Switch Station
OUT03	OUT303	138 kV BKR 1 Closed 52a Status
OUT04	OUT304	138 kV BKR 2 Closed 52a Status
OUT05	OUT305	MOD 1 Closed 89b Status

Breaker failure protection for both 138 kV unit-connected breakers is performed in the 87O switch station relays. Breaker failure protection for the bus-side breaker in the rung (BKR 1 in Fig. 5) is implemented in both primary and secondary 87O relays. Breaker failure initiation (BFI) for the bus-side breaker comes from 87O relay trips, protection and mechanical trips from the plant, and bus differential trips via inputs on the 87O relays. Breaker failure protection for the middle breaker (BKR 2) is implemented in the primary 87O relay and in the adjacent line relay that shares the middle breaker. A contact from the line relay is wired to the primary 87O relay for BFI. Protection and mechanical trips from the plant and 87O relay trips also initiate the breaker failure scheme for the middle breaker. When breaker failure is detected, a breaker failure lockout relay (86BF LOR) is rolled that trips adjacent 138 kV breakers in the switch station. The breaker failure trip is also transferred to the plant to trip the generator. Breaker failure trip word bit and 86BF LOR contact trip state is programmed to assert the word bit OUT301 in the 87O relays (not shown in Fig. 10) which, in turn, close the corresponding MUB OUT01 that trips the 86GT LOR in the plant. For a middle breaker failure event, a DTT signal is sent to the remote end of the line by the local line relays because the remote end relays cannot detect all faults or conditions in the plant that initiate tripping of the middle breaker.

Note that the 138 kV breaker statuses and MOD statuses are also transferred to the plant for generator controls. These statuses are transferred via both System A and System B relays for complete redundancy.

D. Backup Relay for Additional Fiber Failure Considerations

As discussed before, the third backup distance relay is added to the protection scheme to account for a simultaneous failure of the dual fiber channels of the 87O relays. The distance relays were also used in the prestage project configuration to protect the wind farm line in a temporary intermediate configuration. The backup distance relays protect the five tie lines. Protection trips from the distance relays are transferred to the plant via radio communications channels. Radio equipment at the plant was previously used to protect the temporary wind farm line. This equipment was repurposed in the final configuration for backup protection.

One input/output (I/O) module at the plant communicates with another I/O module at the switch station to transfer trips in the backup protection schemes for all five plant terminals. Each I/O module has eight digital bits, which are used to transfer and receive the trips between the five plant terminal relays and the corresponding five switch station backup relays. See Table III for details on how the transfer trips are assigned to the I/O modules. Fig. 11 shows the transfer trips via the backup relay. When the I/O module at the switch station receives trip signals, its corresponding outputs are asserted. These outputs are connected to the associated distance relays, which trip the breaker for the plant line terminals.

TABLE III
I/O MODULE TRANSFER TRIP FROM PLANT

IO/Plant	IO/SWC	Function
IN1/TMB1*	RMB1*/OUT1	Trip from Gen 1 to System A
IN2/TMB2	RMB2/OUT2	Trip from Gen 1 to System B
IN3/TMB3	RMB3/OUT3	Trip from Tie Auto
IN4/TMB4	RMB4/OUT4	Trip from Startup Transformer
IN5/TMB5	RMB5/OUT5	Trip from Gen 2 to System A
IN6/TMB6	RMB6/OUT6	Trip from Gen 2 to System B
IN7/TMB7	RMB7/OUT7	Trip from Gen 3 to System A
IN8/TMB8	RMB8/OUT8	Trip from Gen 3 to System B

TMB1* is a transfer digital bit that asserts for IN101 energization.

RMB1* is a receive digital bit that asserts the output contact OUT1.

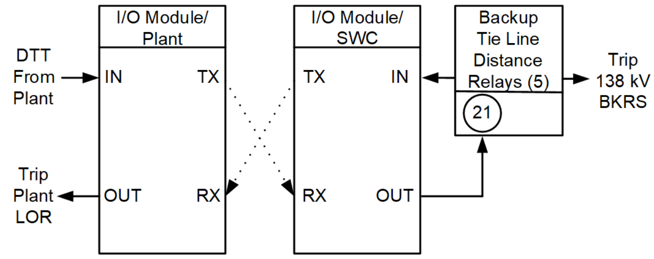

Fig. 11. Backup relay transfer trips.

E. Repurposing DSS-Based Relays for Intermediate Stages

During Stage 0, the drop-in control house module with relay panels was installed in the new switch station. Before any existing lines could be transferred to the new station, it was important to electrically tie the existing station to the new station as part of the same construction sequence stage. During the construction sequence Stages 1 and 3, three 138 kV temporary tie lines were constructed between the existing switch station and the new switch station to provide adequate power flow between generation and the new switch station line terminals. The 87O relay panels that were designed to protect the overall differential zones in the final configuration were repurposed to protect the temporary tie lines.

For the final configuration, an 87O relay protection zone includes a generator, GSU transformer, and 0.5 miles of transmission line. For an intermediate stage, the relays are configured and set to protect only the short transmission line between the existing switch station and the new switch station, which is shown in Fig. 12. The Appendix includes the construction sequences for Stages 1 and 4 (Fig. 31 and Fig. 32), which show the temporary Tie Lines 1, 2, and 3 between the two stations. The protection zone for temporary tie lines includes three breakers, one in the existing station and two in the new breaker-and-a-half switch station. Three CT inputs, one from each breaker, were required to protect the temporary tie line. This was fewer than the CT inputs in the final configuration. The time-domain-link-enabled relays were configured with a total of three merging units per temporary tie line protection: two merging units in the switch station and one in the existing station. The 87O transformer differential relay is used to protect the temporary tie line by turning off transformer protection-related settings, such as harmonic restraint and harmonic blocking. Drawings, fault studies, relay settings, and commissioning and testing plans were developed for each stage, specifically for the three temporary tie lines to maintain protection reliability and safety. Repurposing the same relays, merging units, and panels for different intermediary stages allowed for significant cost and schedule benefits while enhancing safety and quality.

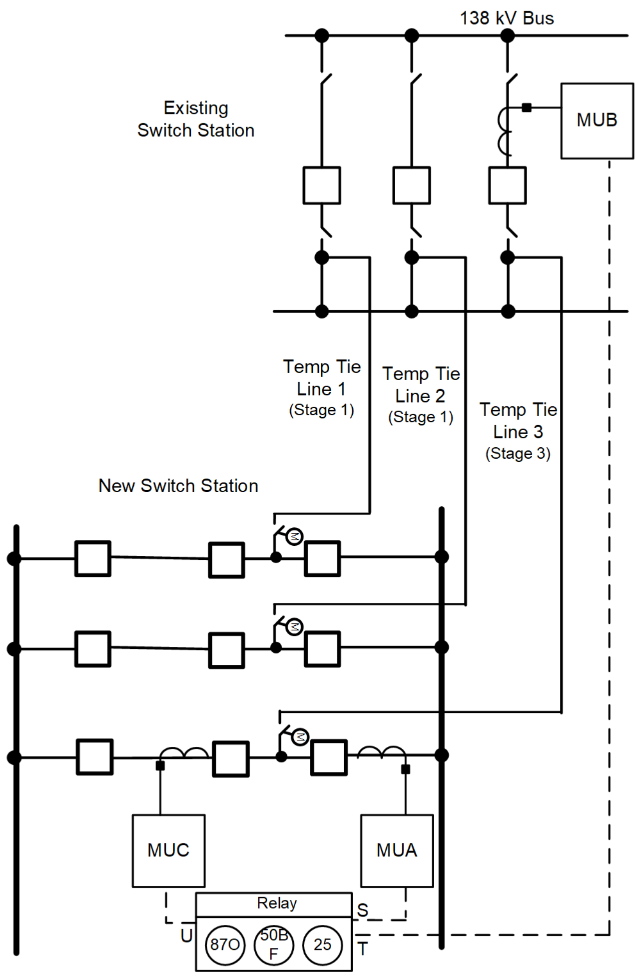

Fig. 12. Temporary tie-line protection by repurposing 87O relay and merging units.

IV. Best Practices and Lessons Learned

One of the core goals of any station build or upgrade project is to maintain the highest level of safety and quality. Reducing the likelihood of undesired operations in P&C applications is key. The best opportunity for a P&C error to be identified and corrected is in one of the following six execution phases of the project: 1) P&C design origination, 2) P&C design review, 3) settings origination, 4) settings review, 5) functional testing during FAT, and 6) functional testing before onsite energization. This section discusses several best practices and lessons learned scenarios that could be useful during project execution phases. One may consider building a checklist, which is routinely updated, to capture and share similar best practices and lessons learned for future applications. These checklists should be used in one or more of the origination, review, and testing phases as part of a quality review process. The key is to catch an error before it goes through all layers of quality review and testing.

A. Generator Protection Trip and Close Considerations With MOD Use

Fig. 13 shows the simplified one-line diagram of the original configuration of the generator unit connection to the system. In this setup, the single generator unit breaker acts as the point of isolation for the generator unit to the system.

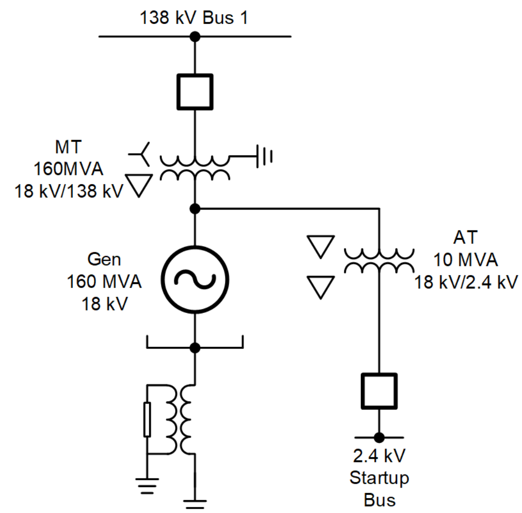

Fig. 13. Original unit generator/transformer configuration.

This system was upgraded to the new breaker-and-a-half substation configuration as part of the upgrade project. A simplified one-line diagram of the upgraded configuration is shown in Fig. 14. As seen from the figure, a MOD switch is typically installed between the breakers at the substation and the high side of the GSU transformer. The main purpose of the MOD switch is to be the isolation point between the plant and the transmission switch station. It is typical for the plant and transmission station teams to be independent of each other and have different operating needs for the breakers.

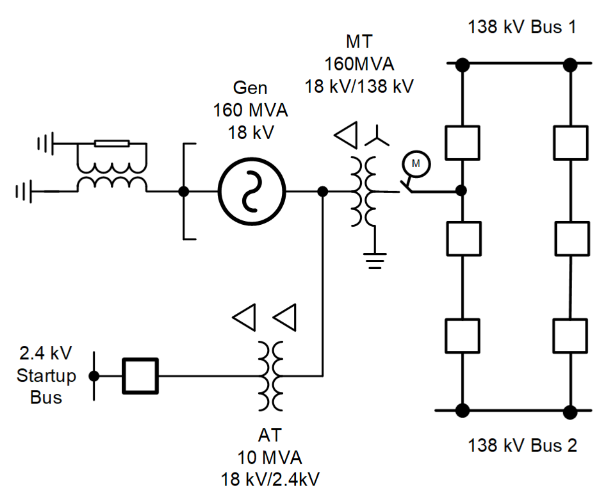

Fig. 14. A typical breaker-and-a-half station with MOD as the point of isolation for a generator unit.

For this project and other such typical applications, the MOD status plays an important role in the overall operation of the protection and operating configuration. The MOD status (89a or 89b contact, or both) is wired to the protective relay inputs and available as a status indication to both plant and transmission station teams.

Manual and SCADA tripping of the unit breakers are allowed by plant and transmission teams, irrespective of MOD status (open or closed). However, the closing of the breakers is dependent on MOD status. With MOD closed, only the plant can close a breaker with synchronism (live line—live bus) established. With MOD open, the transmission team can control the breakers and issue close commands under all conditions except dead line—dead bus. With MOD open, the transmission team can maintain control of the breakers as transmission breakers and close/open the breaker-and-a-half rung as necessary for maximum transmission operation flexibility and system reliability. Opening or closing operations of MOD can occur only when both breakers are open. There are physical and logic interlocks for this.

For protection trips coming from the plant (e.g., generator relay protection and/or other similar trips), a transmission team settings engineer may consider supervising the generator protection trips to the breakers with MOD status. See Fig. 15 for example logic for this configuration. IN301 represents a protection trip coming from the plant, supervised by NOT IN221 or NOT of MOD 89b status. Only when MOD is closed, as shown by the 89b status contact, will the protection trips go through. This could potentially help the transmission station team to avoid any standing trips when MOD is open and to be able to close the generator rung breakers for maximum operating flexibility. Extreme caution is advised when considering this approach. Critical protection could be blocked when needed the most.

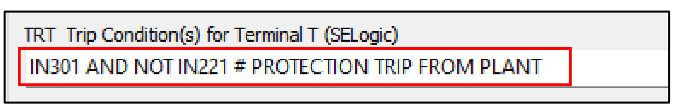

Fig. 15. Example trip logic from plant (not recommended to use MOD status).

Per IEEE C37.102-2023—*IEEE Guide for AC Generator Protection*, Section 6.3.3.3, disconnect switch auxiliary contacts are not considered reliable. “Due to contamination, adjustment, and linkage problems, the auxiliary contacts may not properly close, and vital protection may be out of service when needed most. Several very serious accidents may be traced directly to using disconnect switch auxiliary contacts to disable protection and this practice is NOT recommended” [3].

MOD contact supervision should NOT be applied to protection, manual, or SCADA trips. Non-protection trips (mechanical or operational) may, in some cases, still need to use MOD supervision to maintain existing scheme configuration.

A similar lesson learned was noted by the authors in a lower-voltage industrial switchgear application (not related to the switch station upgrade projects discussed in this paper). In that application, the protection engineer had inadvertently utilized the 52a contact in relay logic to supervise manual and SCADA trips. During a typical maintenance routine, a need was identified to trip a switchgear breaker. However, due to a failed 52a contact status, the end user was not able to issue the trip. Additional unwanted safety risks would need to be considered to trip the breaker. The logic was subsequently modified on all applications to remove the 52a supervision.

For breaker close logic, MOD contact status is likely going to be needed as part of relay logic. As noted before, if MOD is closed, only the plant can close the breaker under synchronism check conditions. If MOD is open, the transmission team can control the breakers by issuing a close command under desired permissive requirements. Hence, the actual physical status of MOD becomes critical.

As a lesson learned and best practice recommendation, consider adding physical field verification of MOD status in any close operating process, prior to any associated operation. Simply relying on MOD status in logic could result in unwanted challenges with close under unexpected conditions, affecting the safety and reliability of the system. In addition, consider adding logic for MOD contact disagreement. Consider unlatching close for this event so that a close is not allowed to go through when an active MOD status disagreement exists. Consider adding an alarm for this condition to alert the operator and to resolve the discrepancy as soon as possible. Fig. 16 shows an example of MOD disagreement logic. Consider adding these lessons learned and best practices to your checklist for future projects.

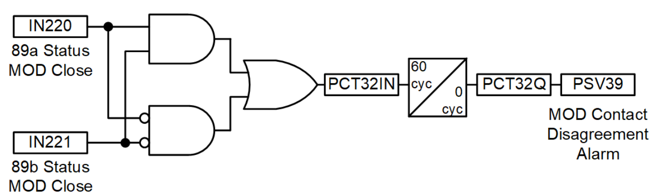

Fig. 16. Contact disagreement alarm for MOD.

Another potential, easy-to-miss consideration is the use of low- or no-current condition logic in the breaker failure schemes of transmission breakers that are for unit-connected generators. Many conditions that can cause severe damage to the generation system are not accompanied by high currents [3]. Typical transmission station relaying standards may not include additional no-current logic for the breaker failure schemes and adding the logic may easily be missed. The lower AND gate of Fig. 17 shows one option for implementing breaker failure logic for low- or no-current condition utilizing breaker status. Application considerations for generator low-current breaker failure can be reviewed in [8].

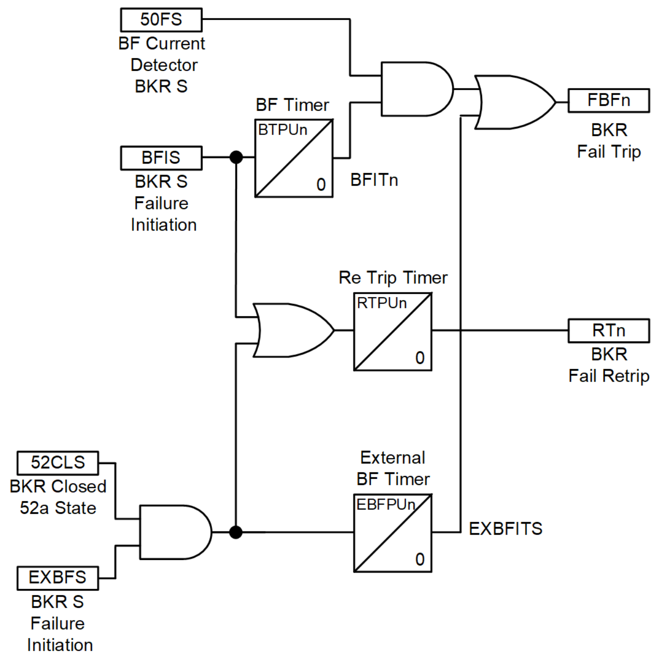

Fig. 17. Breaker failure scheme with low- or no-current logic.

It is recommended to consider disabling reclosing on unit-connected breakers [7]. In breaker-and-a-half or ring bus applications, when the adjacent shared middle breaker circuit is a line, it is important to disable reclosing and manual close of the middle breaker from line relays that share the middle breaker with a generator-utility tie line.

B. *Verifying As-Built Station Physical Layout vs. Issued-for-Construction (IFC) P&C Three-Line Drawings*

Station physical layout drawings are typically developed by the station design team and are included in the overall station design drawings package. The station physical layout shows detailed information on how each piece of substation power system equipment, such as transformers, breakers, and other equipment, will be laid out and connected physically in the substation. The construction team utilizes this drawing package for substation construction. Fig. 18 shows a snapshot of one such station physical layout. Note how the A-phase is shown connected to Bushings 1 and 2 of each breaker (B172 and B272). Similarly, B-phase is connected to Bushings 3 and 4, and C-phase to Bushings 5 and 6. Per each individual utility standard, the phase connections are established and shown accordingly on the station physical layout. Typically, the station physical layout drawing is developed well in advance of the P&C design drawings package and is used as a reference in developing the protection package.

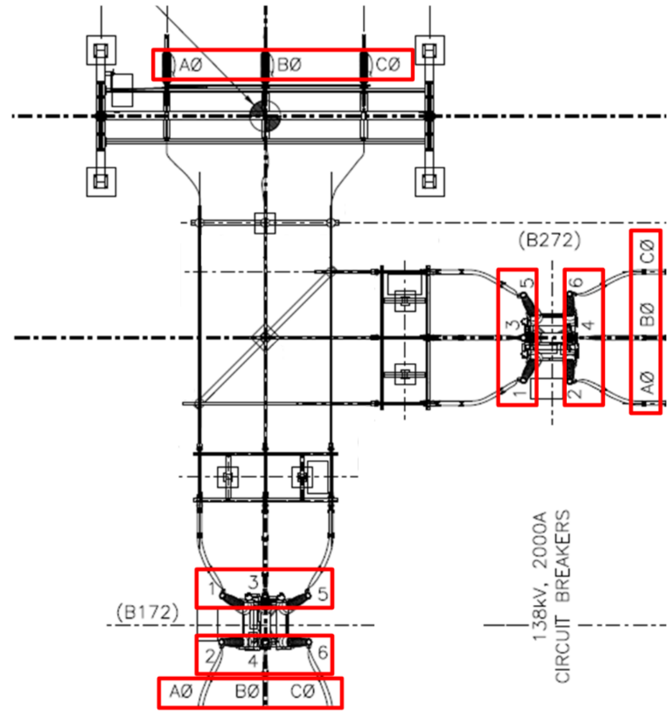

Fig. 18. Simplified station physical layout drawing.

Protection three-line drawings are developed by the P&C design team and are part of the set of drawings that show instrument transformer connections to relay ac inputs. Fig. 19 shows an example of a protection three-line drawing that was developed based on the station physical layout shown in Fig. 18. As shown in the protection three-line diagram, and identical to the station physical layout, A-phase is connected to Bushings 1 and 2 of each breaker. Similarly, B-phase is connected to Bushings 3 and 4, and C-phase to Bushings 5 and 6. The ac connections to the relay panels are made and tested in accordance with the P&C design drawings.

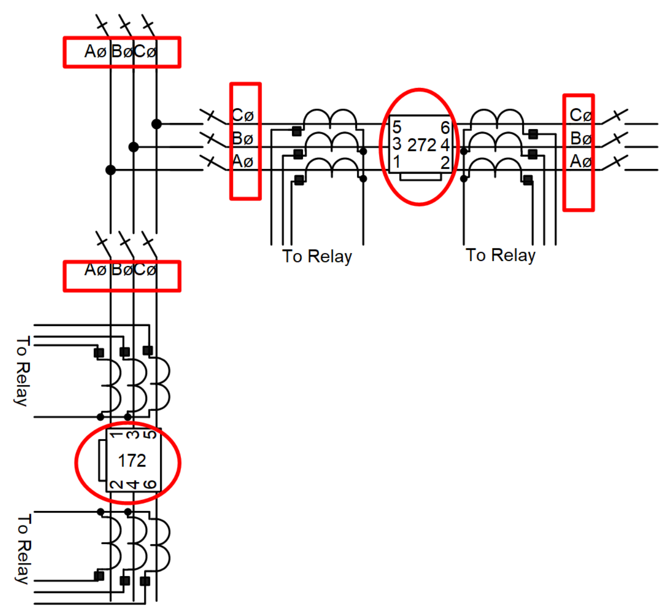

Fig. 19. Simplified P&C three-line diagram.

Experience has shown that in some cases, during construction, it may not be physically feasible to orient certain major electrical equipment such as breakers, in accordance with what may have been originally planned and shown on the station physical layout drawing. In such cases, for example, a breaker may get installed 180 degrees off from the original position. An example of the revised station physical layout with this change on B172, is shown in Fig. 20. The bushing locations on B172 are now flipped, with A-phase shown connected to Bushings 6 and 5, B-phase to Bushings 4 and 3, and C-phase to Bushings 2 and 1. If because of last-minute schedule challenges, lack of communication, or other unforeseen factors, the P&C design or settings team is not made aware of this change, the relays would still be wired per the original protection and control three-line drawings (as shown in Fig. 19). The relays in this case would now be wired to incorrect bushing CTs, with incorrect polarity and phase connections, leading to a case of undesired operation if undetected. Note also that the breaker itself would lose overlapping zones of protection for the above configuration, if left undetected.

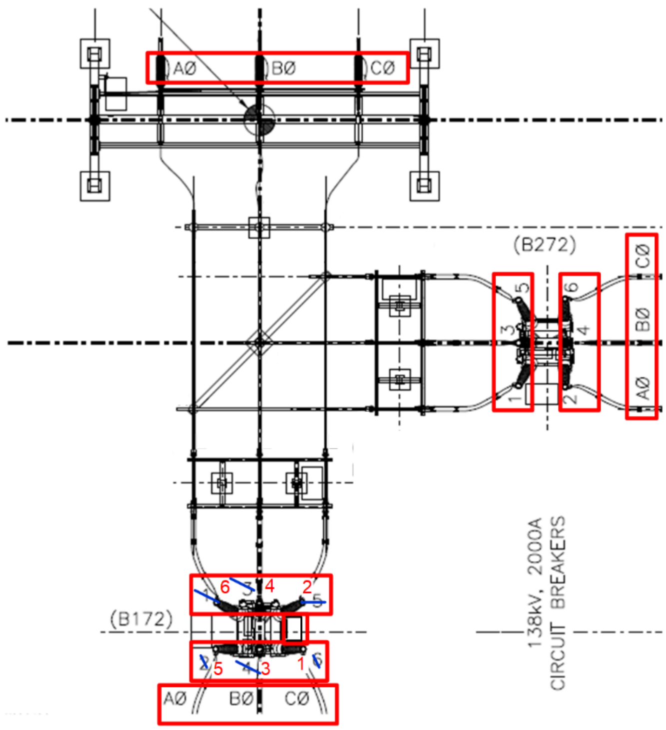

Fig. 20. B172 physical arrangement flipped.

Actual cases of undesired operations and last-minute scrambles to update drawings, settings, and wiring in the field during critical outages because of the physical orientation of equipment being different than the orientation on the P&C drawings have been noted.

As a lesson learned and best practice recommendation, the P&C design drawings team and settings team (originator and reviewer) must review as-built station physical layouts and compare them to the IFC protection three-line drawings as part of the design and settings development process. Field verification of actual connections versus the connections shown on these drawings is also recommended. The importance of communicating any such field changes to all team members (the end-user station design, construction, and protection teams) must also be emphasized.

C. Verifying Transformer Nameplate With As-Built Station Physical Layout and IFC P&C Three-Line Drawings

A similar best practice must be considered with respect to use of the actual transformer nameplate as part of the protection design drawings and relay settings development process for transformer protection. In many cases, the authors have seen reliance on nameplate data shown on P&C design packages, which may have been copied from another project or inaccurate for some other reason, potentially leading to incorrect design or settings errors and an undesired operation.

Another example is when the transformer delta winding configuration connections, as shown on the nameplate, are drawn incorrectly on the three-line drawing and/or the phase connections to the transformer bushings are shown incorrectly. Fig. 21 shows a field case of a transformer nameplate (only the delta winding shown for this discussion) with the field verified ABC phase connection to transformer low-side Bushings X1, X2, and X3.

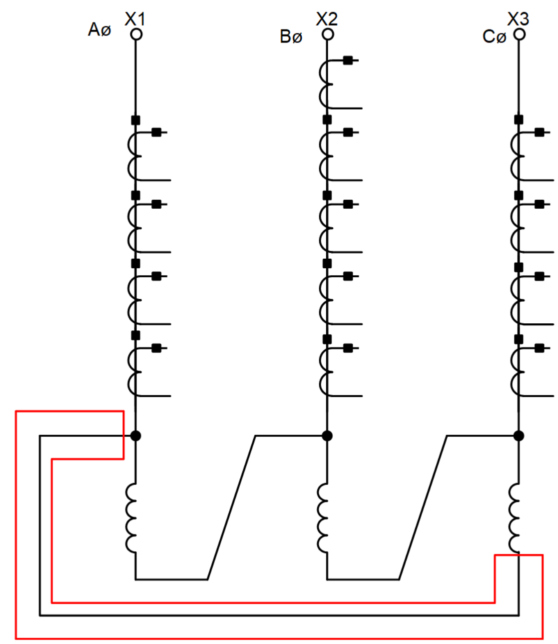

Fig. 21. Transformer nameplate (DAC configuration).

As shown on the nameplate, with the polarity of X1 (A-phase) connected to the non-polarity of X3 (C-phase), the actual physical connection of the delta is in a DAC configuration.

Fig. 22 shows the protection three-line drawing for the same project. This drawing incorrectly shows polarity of X1 (A-phase) connected to non-polarity of X2 (B-phase) or a DAB configuration, which represents an incorrect configuration on the three-line drawing. The protection settings engineer may inadvertently be challenged by such discrepancies for transformer protection settings, causing the transformer CT compensation settings to be incorrect. (Detailed considerations with respect to transformer connection configuration, compensation settings, and other challenges are covered in [4].)

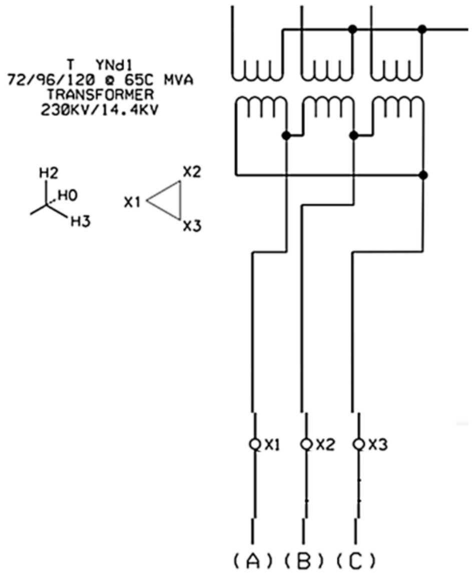

Fig. 22. Transformer three-line diagram—incorrect DAB configuration that does not match the nameplate.

The authors recommend the following best practices and lessons learned for both design and settings teams with respect to this discussion.

- Consider using and reviewing the actual transformer nameplate for transformer P&C applications.
- Consider verifying that the transformer internal connections shown on the three-line drawings match the nameplate.
- Consider verifying that the phase sequence connected to the transformer bushings on protection three-line drawings matches the phase sequence indicated in the substation general arrangement (station physical layout drawings) or by field verification. (For example, the A-phase connected to H1/X1, B-phase to H2/X2, and C-phase to H3/X3 for bushing connections).

Review best practices and recommendations in [4]. Following these practices will help avoid incorrect CT compensation settings being applied in transformer differential relays.

D. Breaker Bypass Switch

Fig. 23 shows a simplified one-line diagram of a 138 kV/69 kV/2.4 kV autotransformer with the 69 kV feeding a downstream station. The 69 kV breaker feeding the downstream system has a bypass switch installed. Although not very common throughout the co-op system, some legacy substations at 69 kV and lower have breakers with bypass switches. The main purpose of the bypass switch is to allow the downstream load to be fed in the event of a maintenance or repair requirement on the breaker. This autotransformer is protected by dual microprocessor-based transformer differential protection relays. The primary relay (87O) zone consists of an overall differential zone from the 138 kV breaker-and-a-half bus breaker CTs, 69 kV breaker CTs, and 2.4 kV delta tertiary breaker CTs. The secondary relay (87T) zone uses the 138 kV high-side transformer bushing CTs, 69 kV breaker CTs, and 2.4 kV delta tertiary breaker CTs for a dedicated sensitive transformer differential zone. Detailed autotransformer protection concepts are not covered in this paper but can be found in [5].

As shown in Fig. 23, and of interest for this discussion, the 69 kV breaker bushing CTs are used as part of autotransformer (ampere-turn-based [1]) differential protection zone relays. Bypassing the 69 kV breaker with the bypass switch would result in the 69 kV CTs feed to the differential zone to be bypassed. Differential protection loses one of the CT inputs and would not be secure during this operating condition. The co-op legacy practice for such applications has been to disable the high-speed differential protection using a cutoff switch on the relay panel and rely on backup elements to provide protection during this bypass mode. Typical backup protection uses phase and ground time overcurrent elements to cover for any faults during this bypass mode. This causes challenges with slow fault clearing for certain faults and other potential challenges (as discussed in the rest of this section) if the legacy practice is not well understood or documented.

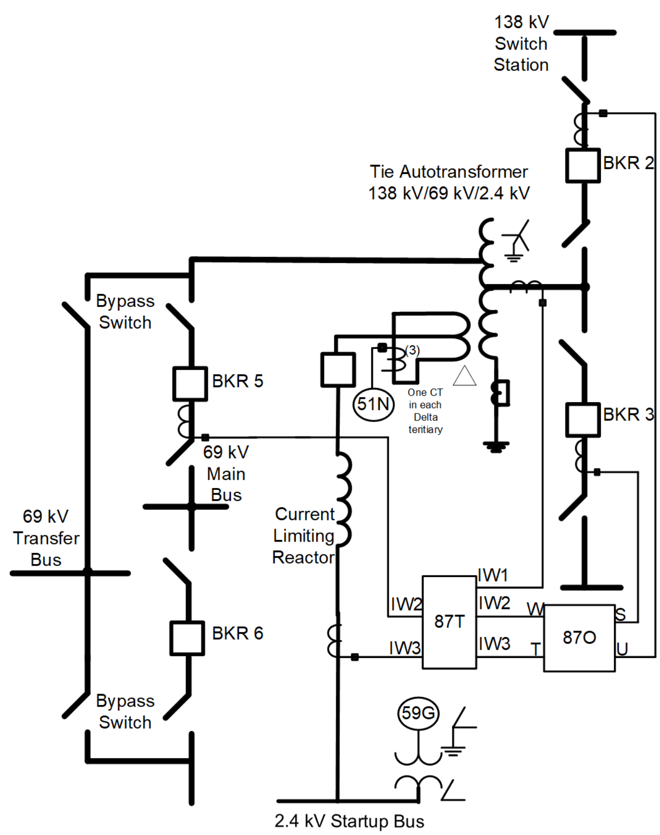

Fig. 23. Tie autotransformer with bypass switch on 69 kV breaker.

It is typical for the fault current to be extremely high for phase faults on the tertiary bus zone. In this case, the fault current for phase faults is in the range of 80 kA, when not limited by the reactor, and in the range of 50 kA, after the reactor (as shown in Fig. 24). The purpose of the 2.4 kV series reactor is to limit the phase fault current in such applications. Such high fault currents (and the use of a reactor in delta tertiary) is noted in [5].

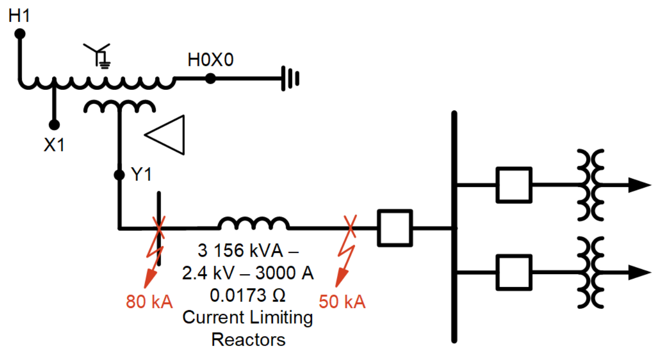

Fig. 24. Extremely high fault current—tertiary phase faults.

A review of the existing overcurrent protection settings and associated coordination study showed that the operating time for the backup phase time overcurrent element for a three-phase fault on the tertiary bus is in the range of 1 second. This represents the worst-case fault clearing time for this application. While a faster operating time is desired, this element has to be coordinated with other phase elements it is backing up and, hence, may result in the need for slower operating times. Breaker maintenance time may be on the order of several hours to a few days during the bypass mode. Exposing the system to potential phase faults and the resultant delayed clearing presents a safety and stability risk to the overall operation of the power system. Arc-flash ratings for the system connected to the tertiary bus would be at elevated levels in the presence of these slow-clearing phase faults. It is important for the protection team and system operators to be aware of this elevated safety risk during the bypass mode, when the differential protection is disabled.

The authors recommend the following best practices and lessons learned with respect to this discussion. Legacy practices, such as the use of bypass switches on breakers and subsequent challenges to the availability of system protection for all fault scenarios, should be carefully evaluated. Overall, the use of a bypass switch on a breaker and the corresponding need to disable high-speed differential protection using a cutoff switch should be avoided, unless absolutely needed for operations. When used, document the purpose or use of the cutoff switch on the system one-line diagram or schematic drawings for future reference. If not documented, there is a potential for any future upgrade to easily miss using the cutoff switch to bypass differential protection, leading to either an undesired operation or a scramble to add the cutoff function in the new upgraded protection scheme at the last minute. Another option might be to consider use of 69 kV transformer bushing CTs, if available, for differential protection during bypass switch use. However, this may require careful protection design planning and clear operating procedures to implement. This scenario also presents a Human Performance Improvement challenge, where the operators have to remember to place the differential back in service after testing and/or use of a bypass switch. Add an alarm to indicate this operation mode. The intent is to remind the onsite team to disable the cutoff once scheduled maintenance is complete. If bypass mode is used, carefully evaluate safety and backup protection reliability for these applications.

As a side note, but as an important reminder on best practices related to the operation of a delta ungrounded tertiary, note that any first single-line-to-ground (SLG) fault would not cause significantly high currents. These SLG faults are typically detected by the 59G zero-sequence overvoltage relay. If left undetected, any subsequent second SLG fault on a different phase could result in a phase-to-phase fault, requiring the phase elements to provide adequate coverage. Some utilities consider only alarming for the first SLG fault, with the intent to allow the system to operate in this configuration. This practice must be carefully evaluated, as significant overvoltages may result in the presence of an arcing-type ground fault or other condition that may pose an extremely high safety hazard to the system and operating personnel. This scenario is discussed and covered in [6] with a recommendation to consider tripping instead of only alarming for such cases.

E. Verifying Relay Output Contact Settings With DC Schematics, Not Just an I/O Table

Depending on each individual utility practice and standard, it may be typical for protection design dc schematics to include an I/O table that lists all the I/O used for a given relay application, the I/O functions, and various other pertinent details, such as the drawing number where each I/O is located. In one such application, shown in Fig. 25, per end-user standard protection philosophy, an output contact (OUT103) was used as a breaker failure initiate and shown correctly on the dc schematic as wired to an input (IN207) on the relay performing breaker failure protection. However, the I/O table on the same schematic (as shown in Fig. 26) had this output contact labeled as BFI (FUTURE PANEL). The protection team considered only the I/O table as a reference when creating settings and inadvertently set the associated output contact to logical 0 (assuming future panel use), making the contact inactive for BFI.

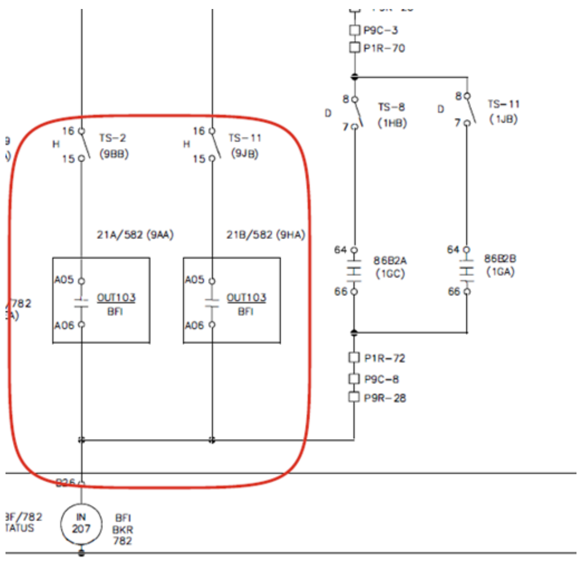

Fig. 25. Relay dc schematic.

21A/582			
	CONTACT/INPUT	DWG	FUNCTION
OUT101	A01 — A02		BFI (FUTURE PANEL)
OUT102	A03 — A04	DC092	BFI/79 TO 421/582
OUT103	A05 — A06		BFI (FUTURE PANEL)
OUT104	A07 — A08		
OUT105	A09 — A10		
OUT106	A11 — A12		
OUT107	A13 — A14	THIS DWG	TEST CONTACT
ALARM	A15 — A16		
IN101	A17 — A18	THIS DWG	52a STATUS BKR 782
IN102	A19 — A20	THIS DWG	52b STATUS BKR 782
IN103	A21 — A22	THIS DWG	52a STATUS BKR 582
IN104	A23 — A24	THIS DWG	52b STATUS BKR 582
IN105	A25 — A26	THIS DWG	DTT
IN106	A27 — A28	THIS DWG	DTT
OUT201	B01 — B02	DC090	TRIP 582 TC1
OUT202	B04 — B05	DC091	TRIP 582 TC2
OUT203	B07 — B08	DC094	TRIP 782 TC1
OUT204	B09 — B10	DC095	TRIP 782 TC2
OUT205	B12 — B13		NOT USED
OUT206	B15 — B16		NOT USED

Fig. 26. Relay dc I/O table.

This simple yet critical error, if not detected, could lead to a potentially serious undesired operation of not initiating breaker failure protection when needed.

The following best practices and lessons learned can be considered with respect to this scenario. It is important for the settings engineer to understand the scheme at a functional level when creating relay settings. The settings originator and reviewer should originate/review settings based on the scheme design given on the dc schematics. The team should not simply rely on an I/O table. If only an I/O table is used, it must have been verified against the schematics as part of a documented quality review process. As an additional layer of consideration, one must yellow-line review dc schematics (including I/O tables), as part of FAT and onsite commissioning functional check reviews to catch any discrepancy errors.

F. *Phasing Verification During Commissioning*

Phasing checks on a power system are critical to ensure that electrical equipment is correctly aligned and operating in synchronization. These checks are essential for maintaining system stability, preventing equipment damage, and ensuring the safety of personnel. Phasing checks verify the phase sequence of the system, confirming that the voltage waves of the phases are in the correct order and rotation. Specialized tools, such as phase rotation meters or voltmeters, are used to identify and confirm the proper phase alignment.

The station rebuild project referenced in this paper had several 138 kV terminals physically relocated from the existing station to the new breaker-and-a-half station, which necessitated the construction of new sections of the transmission lines. This meant that the transmission lines now consist of a section of the conductors that was previously existing and not disturbed up to a certain tower span and newly built sections of the line to reterminate the transmission line into the new station. The conductors of the newly built sections of the transmission lines often undergo transposition between the transmission tower and the H-frame due to system design requirements, and this introduces the possibility of a phase mismatch. One such instance of a phase mismatch is illustrated following along with the commissioning processes used to identify and correct the situation.

Referring to Fig. 27, the section of the transmission line between the remote station and transmission line Tower A was existing, and Section B, terminating onto the H-frame of the new station, was newly constructed. The phasing of the substation bus and the conductors coming from Tower A to the H-frame are also shown in Fig. 27. As evident from Fig. 27, the conductors for outer phases A and C coming to the H-frame from Tower A were swapped, meaning that the phase sequence on the H-frame was ABC instead of CBA, and this error was not caught during the postconstruction walk through of the work site. However, the commissioning procedures included steps to verify that the phasing of the two sources are compatible with each other prior to connecting them together. This included phase sequence verifications by using the secondary voltage signals seen by the line protection relays and the verification of phase sequence on the system primary side across the open breaker disconnect switch of Breaker A by using phasing meters attached to hot sticks. The phasor measurements from the protective relay showed the presence of a high negative-sequence voltage value along with ACB phase sequence compared to the expected ABC phase sequence and negligible negative-sequence quantities. This mismatch in phasing was also confirmed by the phasing meters used across the open breaker disconnect switch on the primary equipment side. As part of confirming and rectifying the problem, busbars and transmission line conductors were walked out to ensure that the error is with the wiring of the conductors between Tower A and the H-frame only, and nowhere else in the station. The conductors landing on Tower A were then corrected to match the design for the correct phase sequence, as shown in Fig. 28, and the equipment was re-energized and verified to have the correct phase sequence before the sources were finally

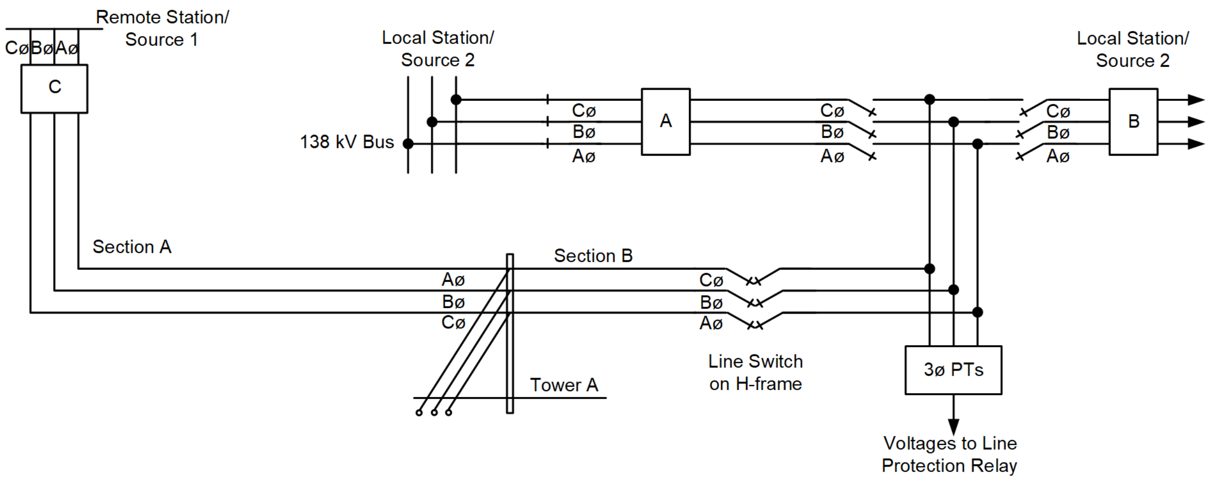

Fig. 27. System incorrect phasing overview.

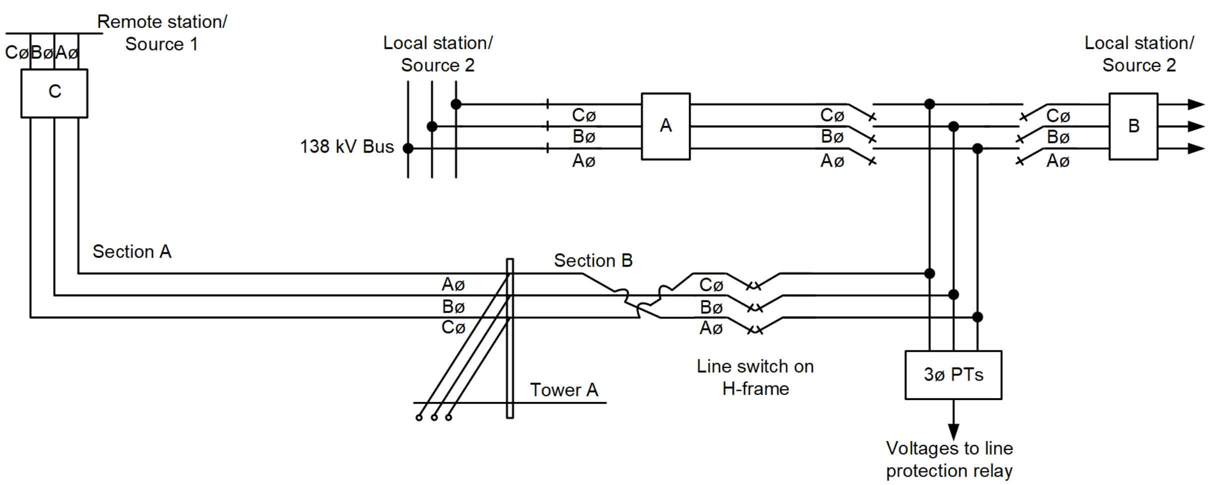

Fig. 28. System correct phasing overview.

connected. Similar commissioning procedures were also followed for the rest of the construction stages of the projects to ensure that the electrical equipment being energized is correctly aligned and operates in synchronization with the rest of the system. Caution needs to be taken with phase shifts caused by transformations, such as wye to delta, which can affect the phase angle and voltage measurements.

G. End-User Utility Perspective

With a project of this scale, the co-op, as the end user, gained experience in many areas and learned some valuable lessons along the way. Overall, the project was a success, but there were a few road bumps.

While the co-op was aware of the poor state of the existing station drawings prior to beginning the project, the full scope of their insufficiency was not taken into account. There were hundreds of circuits at the plant that needed to be manually traced, which was tedious and time consuming, and, in the end, the co-op well under-estimated the amount of labor this effort would take. When considering the need to make safe modifications to old wiring, the hinderance these efforts pose to the project need to be fully taken into account.

The co-op relied heavily upon the experience and expertise of the in-field engineer from the protection engineering team. Having an engineer in the field to support commissioning efforts, who also participated in the design of the station, was invaluable and considered to be an essential aspect of this project getting completed successfully.

The co-op has attempted one other project of this scale at another generation station; however, the main difference between that project and this one was the use of a drop-in control building. For the previous project, the co-op decided to reuse the existing control building. Attempting to reuse the existing control building and protective devices would often lead to technicians needing to perform wiring modifications in old, in-service panels directly next to brand-new panels. A drop-in control building practically eliminates the need to perform in-panel wiring, drastically reducing the amount of time required for wiring while drastically increasing safety by eliminating the chance for errors. At the previous project, often times the old and new panels for a bay were on opposite sides of the building, requiring the use of hundreds of feet of temporary cabling running across the floor—this presented a unique safety issue that was completely eliminated by the use of a drop-in control house.

Another consideration at both generating stations was generator outages. This project presented a greater challenge in that there are three generators, compared to the previous project, and each generator at this plant had to have a new generator lead built to the new station. For the previous station, the generator lead and other transmission lines were not moved. Working with system operations to develop a staging document was critical to the success of both projects.

The co-op, at times, had some struggles maintaining adequate in-field personnel for a project of this nature, while balancing other needs for technicians on the system. This project site location was quite remote to the technicians' main reporting location, and technicians would often need to remain actively committed to working onsite for the full duration of a stage—most stages averaged around 2 to 3 weeks to complete. The co-op also had multiple other large projects occurring at the same time in similarly remote locations. Stages did not run consecutively; there was typically a week, month, or more in between the stages when no work occurred at the project site. During these times, technicians would be committed to other jobs and then return to the project site. Proper consideration should be given to these situations, as the project focus can often be negatively impacted.

V. Conclusion

Developing a construction sequence document is crucial for staged projects. This document is the basis for developing design drawings, settings, and commissioning documents for each stage of the project.

DSS solutions with differential relays were used to provide overall differential zone protection for intertie utility lines. The DSS solution implemented to protect the five tie lines resulted in project cost savings and efficiency gain during staged construction for the application. The solution was adaptable, allowing the protection equipment to be repurposed through various stages. DSS-based design should have clear documentation on relay and merging unit mapping and the relay logic.

It is important to provide complete redundancy for communications channels when deploying DSS solutions. All the communications alarms need to be continuously monitored and flagged in the system.

Caution is needed when using MOD contacts for breaker trip and close logic. Protection trip schemes should not be dependent on MOD statuses. It is recommended to field verify the physical status of the MOD as part of any breaker close operating procedure.

Best practices and lessons learned captured for projects must be documented as part of a standard template, checklist, or other tool and used in quality review processes. These tools allow originator and reviewer teams to reduce undesired operations and act as training tools to avoid repeat errors.

VI. Appendix

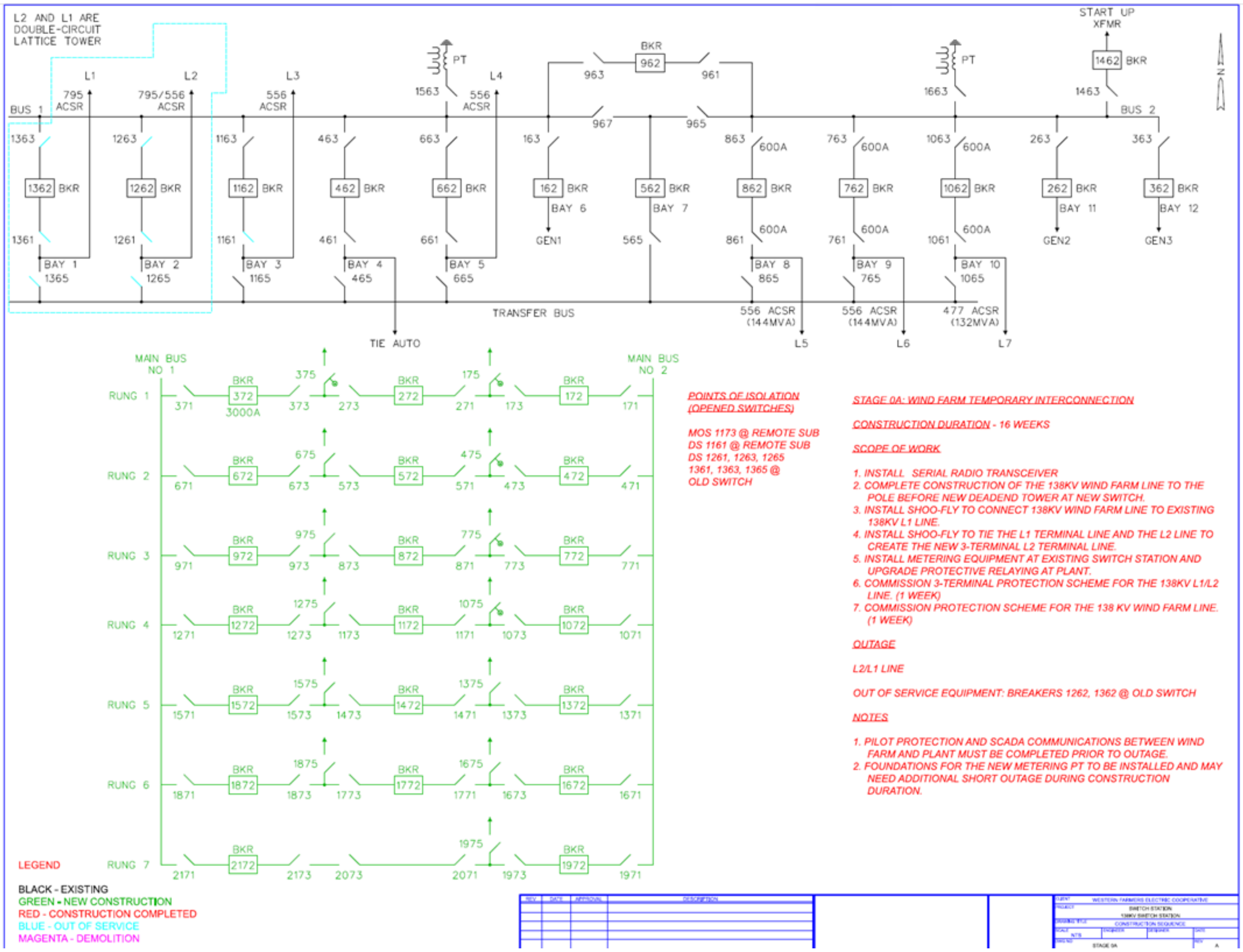

Fig. 29. Construction sequence Stage 0A—wind farm temporary interconnection.

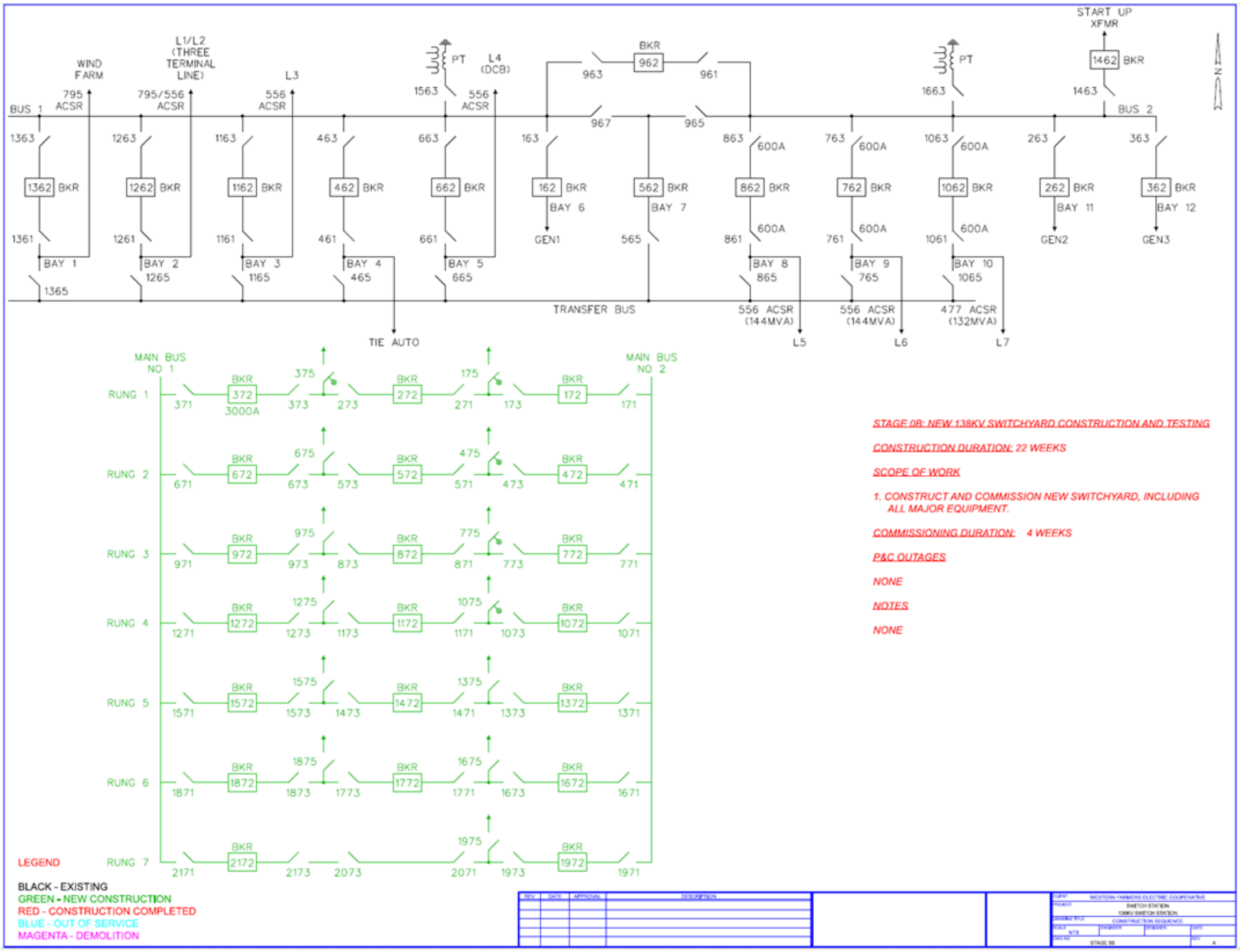

Fig. 30. Construction sequence Stage 0B—new station construction and testing.

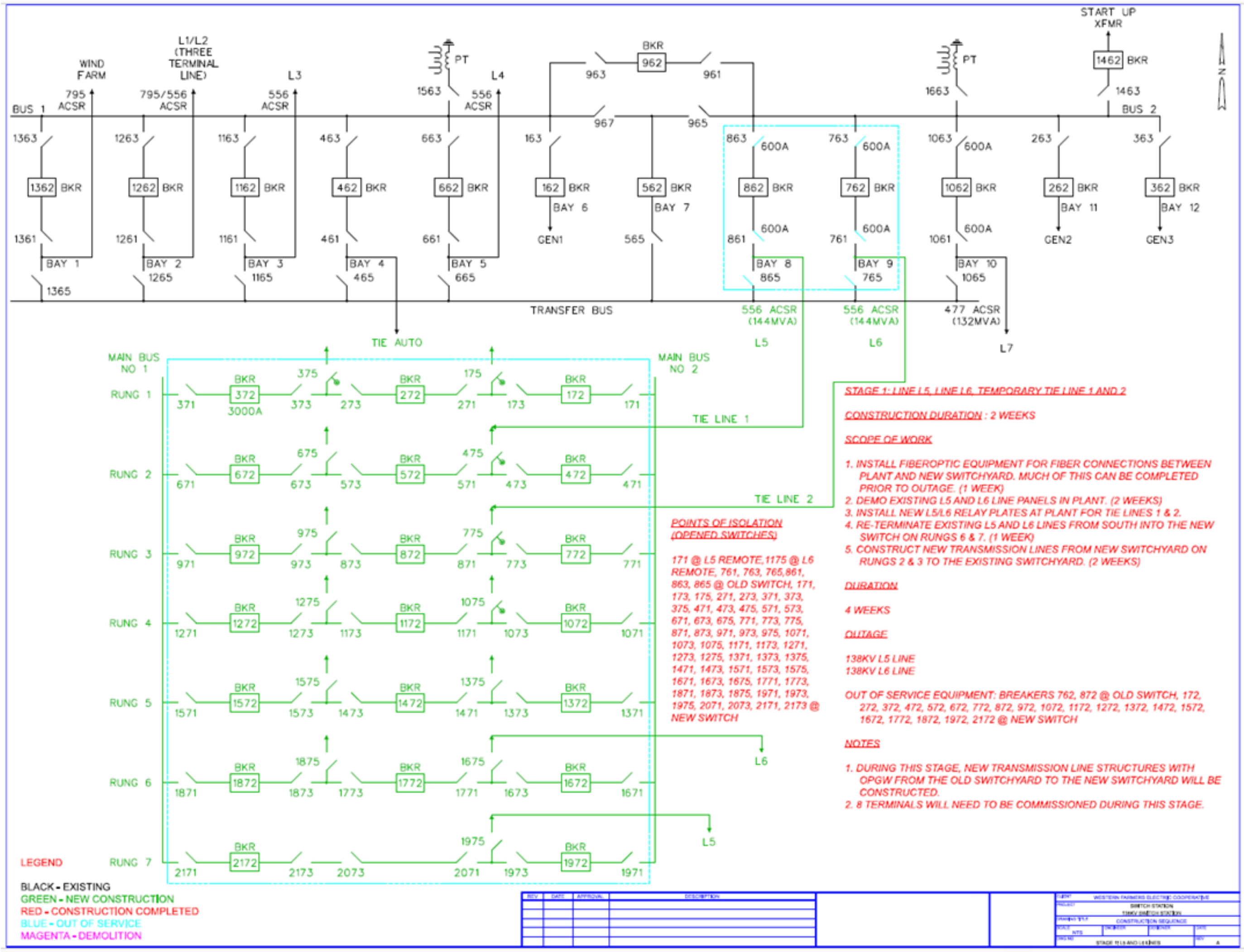

Fig. 31. Construction sequence Stage 1—L5, L6, Temporary Tie Line 1 and 2.

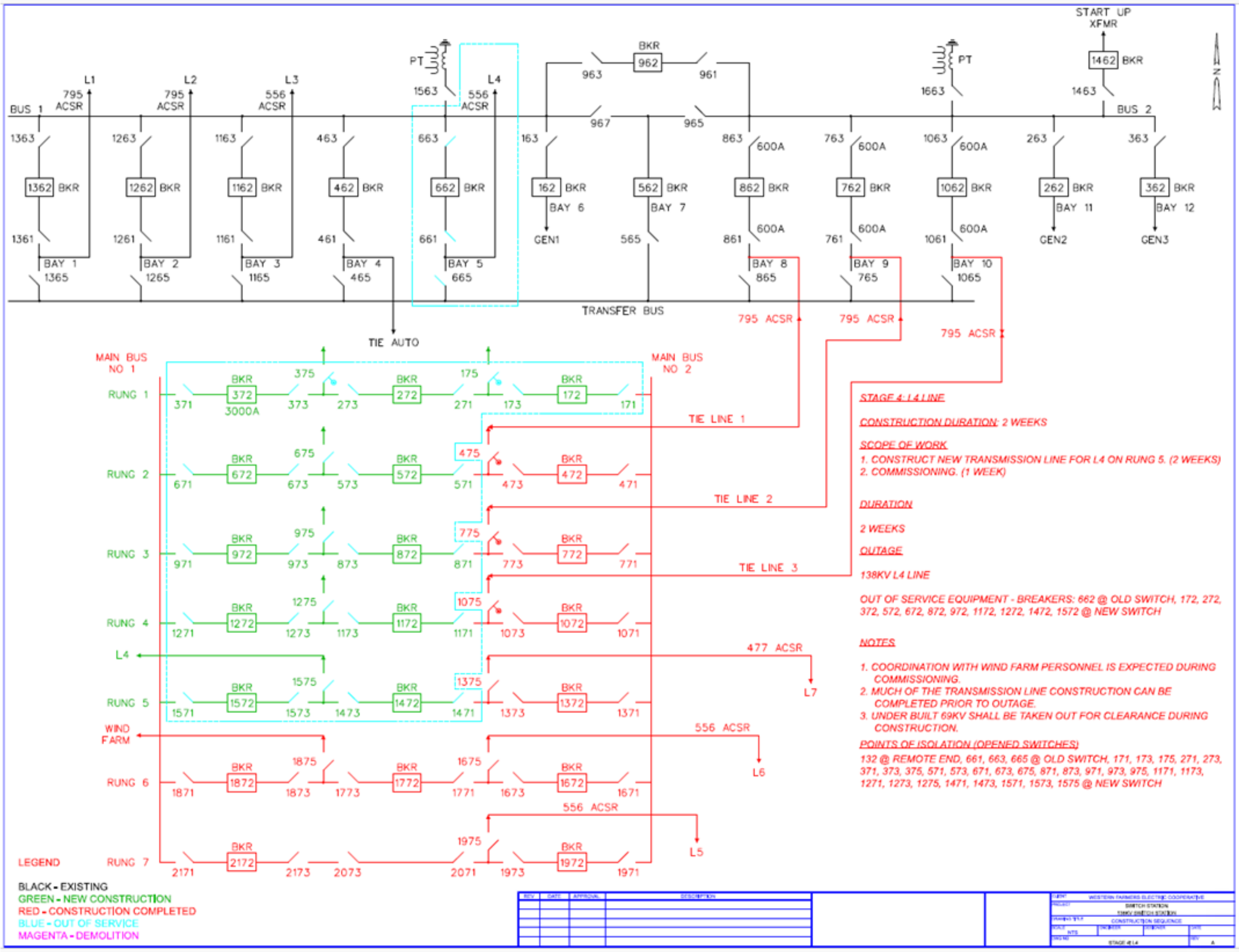

Fig. 32. Construction sequence Stage 4—L4.

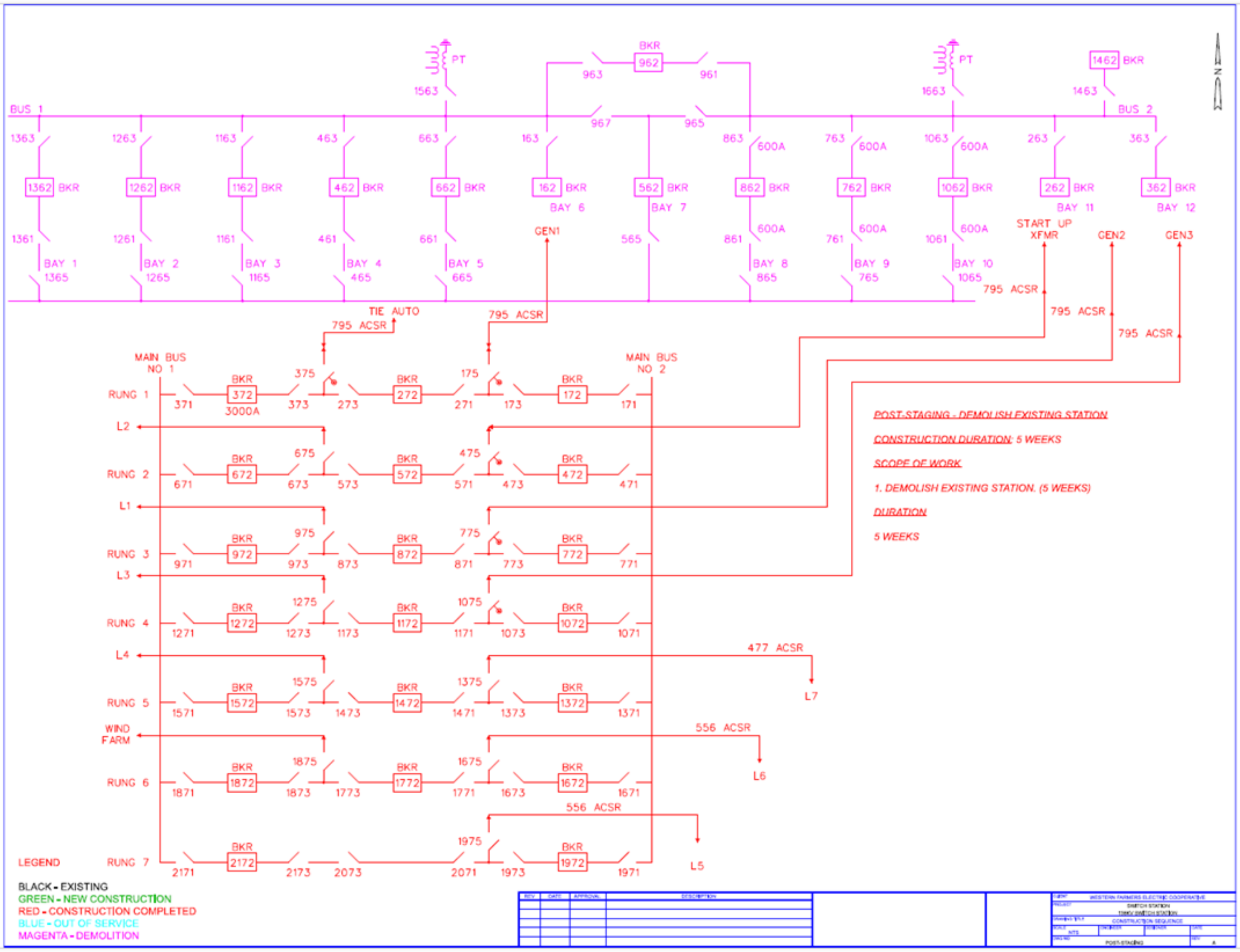

Fig. 33. Construction sequence—final configuration.

VII. Acknowledgment

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IX. Biographies

Matt Neudahl received his BS and Certificate in electric power engineering from Michigan Technological University in 2013. Matt has held roles focusing on system protection and control engineering since 2014 at two G&T cooperatives, Wolverine Power Supply Cooperative and Western Farmers Electric Cooperative. Matt joined Western Farmers Electric Cooperative in 2020 as a system protection engineer level III, and his primary area of expertise is in transmission system protection.

Travis Goucher received his BS in electrical engineering from the University of Oklahoma in 2011. He joined Western Farmers Electric Cooperative in 2011 as a transmission engineer. He is presently the manager of the engineering department. His primary area of expertise is in high-voltage transmission line and station design. Travis is a registered professional engineer in the state of Oklahoma.

Kandarpa Sai Paduru received his MS in electrical engineering from Texas A&M University, College Station, in 2019 and BS in electrical engineering from Indian Institute of Technology Jodhpur, India, in 2017. He joined Schweitzer Engineering Laboratories, Inc., (SEL), in 2019 and currently works as a protection engineer and a supervisor in the Engineering Services division in Houston, TX. He is a member of IEEE.

Sasikala Sreerama received her MS in electrical engineering from the University of Toledo and her BS in electrical and electronics engineering from Jawaharlal Nehru Technological University College of Engineering in Hyderabad, India. Sasikala joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2012 and currently works as a protection engineer in the Engineering Services division in Houston, Texas. She is a member of IEEE and a registered professional engineer in the states of Oklahoma and Texas.

Afam Anunobi received his MBA in 2023 from Kellogg School of Management – Northwestern University, an MSEE from the University of Southern California in 2019, and a BS in electrical engineering from Texas Tech University. He joined Schweitzer Engineering Laboratories, Inc., (SEL), in 2017 as a design engineer. He is presently an engineering manager leading SEL Engineering Services engineering, procurement, and construction management (EPCM) initiative. His primary area of expertise is in substation design, comprising protection and control and physical design. He is a member of IEEE and a registered professional engineer.

Amit Somani received his MSEE from the University of Idaho in 2003 and his BS in electrical engineering from BVM Engineering College, India, in 2000. He joined Schweitzer Engineering Laboratories, Inc. (SEL), in 2003 as a protection engineer. He is presently a principal protection engineer in SEL Engineering Services division. His area of interest and experience is in power system protection and control. He is a member of IEEE and a registered professional engineer.

Bernard Matta received his BS degree in electrical engineering from Pennsylvania State University and MBA degree from the University of Phoenix. He joined Virginia Power (presently Dominion Energy) in 1986 and worked in the system protection department calculating relay settings, performing system studies, testing protection systems, and writing standard procedures. He was on a team that evaluated and implemented microprocessor-based relays to replace electromechanical equipment. Bernard joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2000 and is presently an SEL fellow engineer. He has served many electric utilities and customers throughout the U.S. by providing protection and control designs and relay settings to protect transmission, distribution, and generation equipment. Bernard is a senior IEEE member.

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