Beyond the Relay Protection Upgrade Program

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Abstract—In 2020, Public Service Company of New Mexico initiated a five-year program to upgrade an obsolete microprocessor and solid-state protection system for their line-tapped distribution power transformer. This effort was driven by the failure of multiple relays, the lack of redundancy, and the lack of event reporting data. The successful program has been extended to greenfield projects for line-tapped and bus-tapped distribution power transformers. The configuration of the distribution substation can include up to two power transformers that are connected in a main-tie-main topology at medium voltage, with an indoor metal-clad switchgear assigned to each.

This paper discusses the key protection improvements for more than 50 indoor metal-clad switchgear, including features such as combined overcurrent elements for main-tie-main configurations, integrated breaker failure protection, restricted earth fault protection, arc-flash protection for greenfield substations, and two-zone differential protection for bus-tapped power transformers. The paper also establishes and discusses a standard protection scheme, standard retrofit plates design, standard protection criteria, settings calculation templates, and relay settings templates.

I. Introduction

Public Service Company of New Mexico (PNM) is a regulated utility in New Mexico with operations primarily engaged in the generation, transmission, and distribution of electricity. PNM serves nearly 550,000 New Mexico residential and business customers. PNM's capacity in electric generating facilities, which are owned, leased, or under Power Purchase Agreements, in commercial service as of December 31, 2022, is 2.66 GW. As of year end 2022, PNM owned, jointly owned, or leased 3,428 circuit miles of electric transmission lines (including the Eastern Interconnection Project); 5,767 miles of distribution overhead lines; 6,057 cable miles of underground distribution lines (excluding street lighting); and 250 transmission and distribution substations.

With regard to distribution, PNM currently operates 133 distribution substations, 158 power distribution transformers, and 590 distribution feeders. Before the relay protection upgrade program, the technology of the protection schemes in service included approximately 55 percent electromechanical, 8 percent solid-state, and 37 percent microprocessor relays.

In 2020, PNM identified that the solid-state and microprocessor relays had begun to cause field issues, which created exposures in their distribution system. The previously mentioned relay platforms were obsolete and started failing to trip during fault events. The solid-state relays do not provide event reports or relay fail alarms for supervisory control and data acquisition (SCADA) supervision. Additionally, PNM was not able to get much technical support for the relays. Furthermore, the microprocessor relay software was not compatible with the PNM computer operating system upgrades, nor did it meet cybersecurity standards. For example, during a storm, one of the phases of a transmission line that was not connected with the distribution substation dropped onto the distribution lines and caused significant loss of load. Upon further investigation at the distribution substation, it was discovered that 80 percent of the solid-state relays, which incidentally did not have a relay fail alarm, failed to trip because they were turned off. Therefore, PNM made the decision to undertake a relay protection upgrade program that year.

In this paper we describe the two types of distribution substations that PNM has standardized in its distribution system. Next, we explain the main enhancement features added to the protection system. Then, we discuss the protection system that has been adopted and standardized by PNM. Following this, we provide the detailed protection criteria for all elements used in the protection system. Next, we present the PNM Engineering Design Package (EDP). Lastly, we disclose how PNM addresses commissioning efforts, describe the testing procedures, and discuss how event report analysis tools can help troubleshoot current transformer (CT) wiring issues.

II. Background

The PNM distribution system includes both line-tapped and bus-tapped substations. The majority of their existing substations are line tapped; however, PNM has added bus-tapped substations in recent years.

The configuration of line-tapped substations can include one or two transformers with the entire substation fed by one or two subtransmission lines, as shown in Fig. 1, at 115 kV, 69 kV, or 46 kV voltage levels. The most common configuration for line-tapped substations is one load tap changing transformer that serves four feeders. High-side switching is accomplished by a circuit switcher (CS1 or CS2) and low-side switching is done by switchgear, which includes the main breaker (M10 or M20), tie breaker (T15 or T25), and four feeders (F11–F14 or F21–F24). Distribution voltage levels are 23.9 kV, 12.47 kV, and 4.16 kV, with the most common at 12.47 kV. For line-tapped substations, a second transformer can be added to support a power load increase and for emergency operating conditions.

As an example, consider the configuration of two transformers and two tie breakers in a distribution substation that is fed by two subtransmission lines. For a two tie breaker configuration, one of the tie breakers is normally closed based on the PNM operation standard. Under normal conditions, Transformer T1 is tied to Line L1 and Transformer T2 is tied to Line L2. Thus, the following devices are closed: SW1, CS1, M10, F11–F14, T15, SW2, CS2, M20, and F21–F24; whereas SW3 and T25 are open. Should one of the subtransmission lines be taken out of service, the open transition would be executed to open the line switch (SW1 or SW2, as appropriate) and close SW3, and tie both transformers to either Line L1 or Line L2. If one of the transformers is taken out of service, then the open transition would be executed with Breaker M10 or Breaker M20 opened and Breaker T25 closed. According to the PNM operation standard both transformers cannot be in parallel.

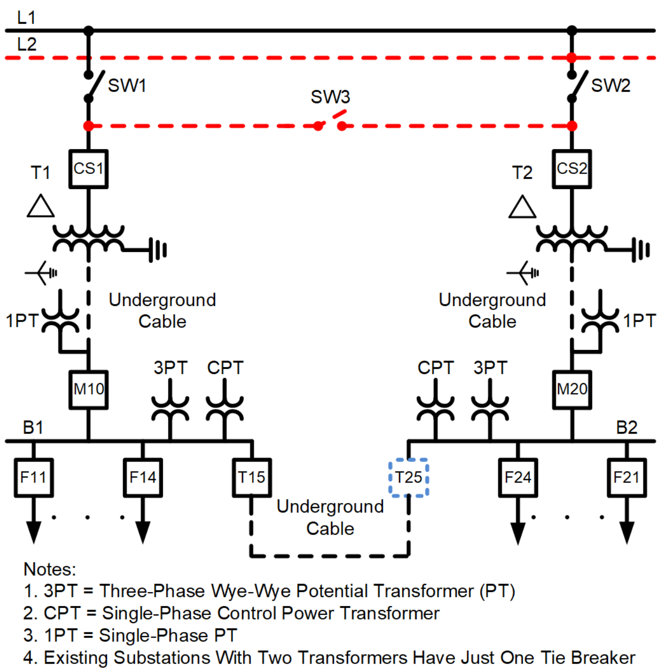

Fig. 1. Simplified single-line diagram of a line-tapped substation.

Bus-tapped substations are fed either from a bus in a subtransmission substation with a breaker-and-a-half arrangement, as shown in Fig. 2 for Transformer 1, or from one of the bays of the subtransmission substation with a ring-bus or breaker-and-a-half arrangement, as shown in Fig. 2 for Transformer T2.

This topology is presently being used for new substations and can have one or two transformers. High-side switching is done by a single breaker (52) or dual breakers (52-1 and 52-2) and low-side switching is done by the switchgear through the main breaker, tie breaker, and four feeder breakers. The typical distribution voltage level is 12.47 kV. Should one of the transformers go out of service, the same open transition (low-side switching) as described for line-tapped substations is executed. As previously stated, according to the PNM operation standard both transformers cannot be in parallel.

III. Enhancement Features

Taking advantage of features and capabilities that modern multifunction relays can provide, such as faster tripping, greater sensitivity, and improved security, PNM decided to include the following enhancement features as part of the Relay Protection Upgrade Program.

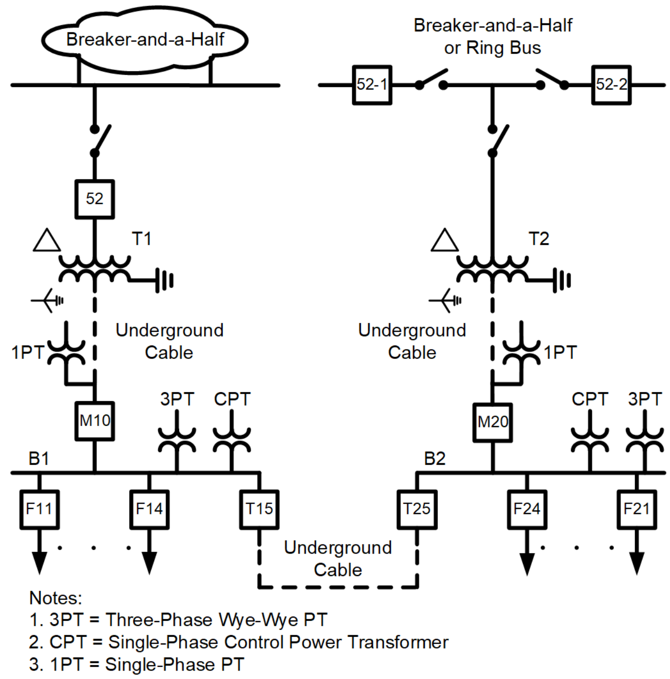

Fig. 2. Simplified single-line diagram for a bus-tapped substation.

A. *Combined Overcurrent Elements*

As stated in Section II, PNM's distribution system operating scenario is that only one of the main breakers will be closed when the tie breaker is closed on their main-tie-main configuration (i.e., open transition).

Main breaker relays use the same CT connections as partial differential protection and perform combined overcurrent for the 51P and 51N elements that were described in Section IV. The protection zone is bounded by the wye-side T1 transformer CTs and the T15 tie breaker CTs, as shown in Fig. 3.

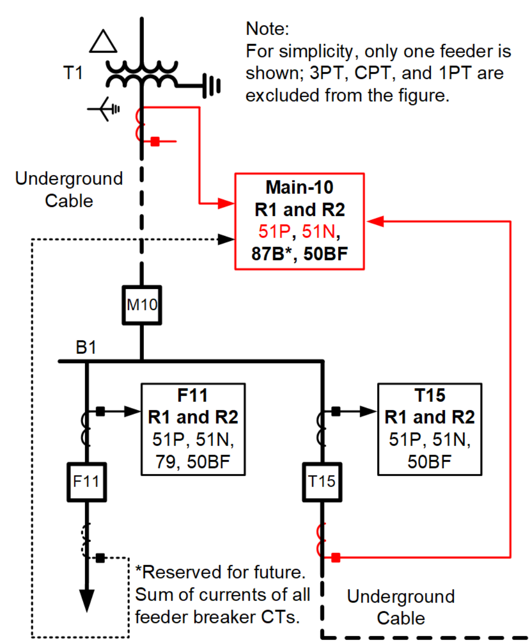

Fig. 3. 51P and 51N elements at main breaker relays use combined overcurrent elements.

The main breaker relays sum the currents for the two signals internally to serve as the operating quantity for the combined overcurrent elements. This application is recommended for the best selectivity and clearing. The combined overcurrent elements act as backup protection for any fault located on either the local bus or local feeders. Therefore, for PNM distribution substations, when the tie breaker is closed and carrying adjacent feeders, coordination between main and tie overcurrent elements is not needed. Instead they can be set at the same operating time, with the main breaker serving as the main breaker for the local bus and local feeders, and the tie breaker serving as the main breaker for the adjacent bus and adjacent feeders. This solution mitigates power transformer and equipment damage by reducing the operating time of overcurrent elements in the main breaker relays and the high-side overcurrent elements in the transformer relays, as shown in Fig. 4.

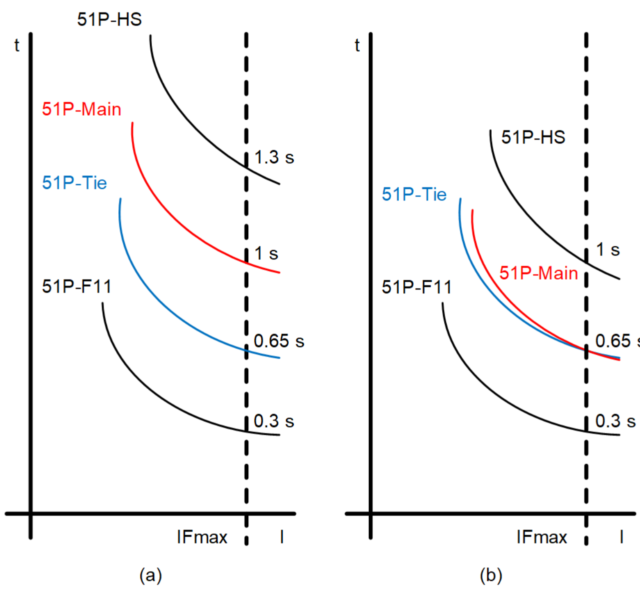

Fig. 4. Comparison of using (a) conventional overcurrent elements versus (b) combined overcurrent elements at the main breaker relays.

B. Integrated Breaker Failure Protection

Fully integrated breaker failure protection is enabled in each of the protection relays. Breaker failure protection is initiated internally by all protection elements tripping the monitored breaker and, upon declaring a breaker failure condition, issues trip signals to all adjacent breakers that are required to open to isolate the failed breaker. This scheme increases dependability because breaker failure protection is not lost upon a failure or an out-of-service condition of any individual relay. This scheme is relatively simple and symmetrical in design. It does not use external breaker failure initiation (BFI) signals and, therefore, reduces the risk of human errors and noise-induced spurious BFI signals, which improves the overall security of the scheme. Further details are available in [1].

C. Restricted Earth Fault Element

The PNM distribution power transformers are delta-wye connected and solidly grounded. For ground faults close to the neutral, a small portion of the transformer winding is shorted to ground. This small change in the winding does not have a substantial impact on the transformer operation and does not significantly change the phase currents. These faults produce low-magnitude phase currents; therefore, they must be quickly detected and isolated because the ground current circulating through the shorted turns can be very high and can cause significant damage to the transformer. Phase differential elements are not sensitive to these faults because the low-magnitude phase current changes. The restricted earth fault (REF) element responds to the neutral current, thereby reliably detecting ground faults closer to the transformer neutral. Reference [2] provides a detailed explanation of the REF element operation principle, settings, and commissioning.

D. Arc-Flash Protection

Reducing arc-flash hazard levels in the switchgear has been one of the primary concerns to address as part of the PNM protection system. Adding bus differential, bus-tie differential, integrated breaker failure, and arc-flash protection helps to achieve the goal of reducing the hazard levels.

For arc-flash protection, the relay technology uses a combined light sensor (LS) and high-speed overcurrent detection for arc-flash events. The shape of the inverse-time characteristic of the LS is fixed, offering robust rejection of unrelated light events. The LS pickup value is typically set higher than the ambient light levels and the outputs are programmed to have an overcurrent element supervising the LS element. The high-speed overcurrent elements use raw analog-to-digital converter samples (16 samples/cycle) and require that two consecutive sampled values exceed the settings threshold to declare an overcurrent condition.

Fig. 5 shows the arc-flash protection scheme for the PNM line- and bus-tapped distribution substations.

The main breaker arc-flash detection (AFD) relays use four bare-fiber sensors for arc-flash mitigation on the following:

- Medium-voltage bus (LS1).
- Main breaker and one potential transformer (1PT) compartment (LS2).
- Three PTs (3PT) compartment (LS3).
- Control power transformer (CPT) compartment (LS4).

The tie AFD relays also use four bare-fiber sensors and cover the following:

- Medium-voltage bus (LS1).
- Tie breaker compartment (LS2).
- 3PT compartment (LS3).
- CPT compartment (LS4).

The feeder relays use only one bare-fiber sensor to cover the feeder breaker and cable compartment.

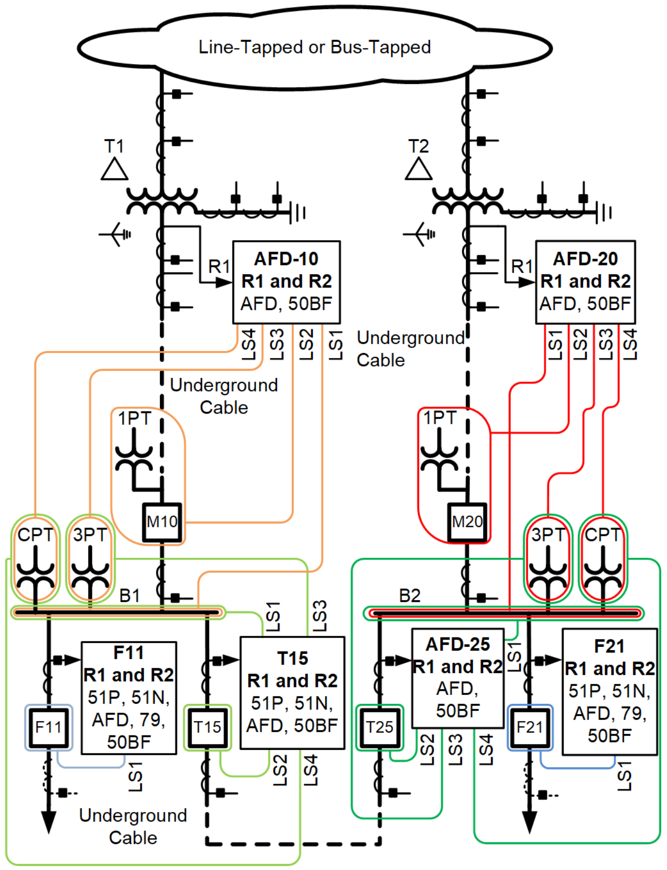

Fig. 5. Arc-flash protection scheme. Only one feeder per bus is shown for simplicity.

This scheme uses hardwired fast hybrid outputs to trip breakers or lockout relays (LORs). For greenfield bus-tapped applications, the arc-flash trip signal is transferred to the transformer relays to trip the high-side breaker(s). Table I summarizes the arc-flash events under normal operation for Transformer T1, shown in Fig. 5, when tie breaker T25 is open. Arc-flash events on the Transformer T2 side behave similarly.

TABLE I
ARC-FLASH EVENTS FOR TRANSFORMER T1 WITH TIE BREAKER OPEN

Arc-Flash Event	Relay	Actions
Any 11–14 feeder (FDR) compartments	FDR-mn*	Trips M10, T15, and 86B1*
Low-side Bus B1	AFD-10	Trips M10, T15, and 86B1
CPT compartment Bus B1	AFD-10	Trips M10, T15, and 86B1
3PT compartment Bus B1	AFD-10	Trips M10, T15, and 86B1
Main breaker and 1PT compartment of Bus B1	AFD-10	Trips high-side breaker(s), T15 and 86B1
T15 tie breaker compartment	T15	Trips M10, T25, and 86B1

* mn = 11 to 14. 86B1 = Bus B1 LOR. 86B1 trips and block close M10, F11–F14, and T15 breakers.

Table II summarizes the arc-flash events for the scenario in which Transformer T1 carries the load from Buses B1 and B2 and both tie breakers are closed. All of the events listed in Table I could happen in this scenario; however, they are not listed in Table II for simplicity. When Transformer T2 carries the load from Buses B1 and B2, the arc-flash events follow similar actions as shown for Transformer T1.

TABLE II
ARC-FLASH EVENTS FOR TRANSFORMER T1 WITH TIE BREAKERS CLOSED

Arc-Flash Event	Relay	Actions
Any 21–24 feeder compartments	FDR-op*	Trips M20, T25, and 86B2*
Low-side Bus B2	AFD-25	Trips M20, T25, and 86B2
CPT compartment Bus B2	AFD-25	Trips M20, T25, and 86B2
3PT compartment Bus B2	AFD-25	Trips M20, T25, and 86B2
T25 tie breaker compartment	T15†	Trips T15, T25, and 86BT*
T25 tie breaker compartment	AFD-25†	Trips T15, M20, and 86B2

* op = 21 to 24. 86B2 = Bus B2 LOR. 86B2 trips and block close M20, F21–F24, and T25 breakers. 86BT trips and block close T15 and T25 breakers.

† Relay-to-relay communications channel is used to exchange LS and high-speed overcurrent detection signals.

Arc-flash protection has helped PNM mitigate the worst-case incident energy from 60 cal/cm^2 to less than 8 cal/cm^2. According to [3], the incident energy depends primarily on the calculated arc current, arcing duration, and working distance. The calculated arc current is obtained by short-circuit software that is capable of performing arc-flash studies. The working distance is obtained from IEEE Standard 1584-2018, IEEE Guide for Performing Arc-Flash Hazard Calculations, Table 10 [3]. The arcing duration is obtained using the operating time of different intermediate devices to clear the fault. Table III summarizes the operating time of the various devices involved in arc-flash protection to estimate the reduction in incident energy levels for the PNM distribution substations.

TABLE III
OPERATING TIME OF DIFFERENT INTERMEDIATE DEVICES

Device	Operating Time	Application
AFD relay	5 ms/0.3 cycle	Line and bus tapped
Switchgear breaker	83.33 ms/5 cycles	Line and bus tapped
Communications channel	4.17 ms/0.25 cycle	Line and bus tapped
Circuit switcher	100 ms/6 cycles	Line tapped
High-side breaker	50 ms/3 cycles	Bus tapped
Auxiliary relay	8 ms/0.5 cycle	Bus tapped
Relay digital input	4 ms/0.25 cycle	Bus tapped
Relay digital output*	6 ms/0.36 cycle	Bus tapped

* Standard output.

E. *Two-Zone Differential Elements*

Power transformers with dual breaker terminals are common for PNM in greenfield bus-tapped power transformer substations. According to [4] and [5], there are two distinct zones with different sensitivity and security requirements. These zones are the transformer zone and the bus zone, as shown in Fig. 6.

For security, the protection of the bus zone must have tolerance for high through faults that challenge the performance of the CTs that make up the zone boundaries. Faults that occur in the bus zone produce high currents; therefore, security is of greater concern than sensitivity. The transformer zone requires high sensitivity to detect and clear faults to prevent transformer damage. Security for through faults is not as challenging because the maximum through-fault magnitude is limited by the impedance of the transformer. By forming the two zones with different CTs, as shown in Fig. 6, the CT ratios for the bus zone can be a full ratio to provide the bus protection with the best security for through faults. The transformer zone CTs can have relatively lower ratios to allow for better sensitivity of the differential protection for the transformer. This is an improvement over having just one overall differential protection for the bus and transformer, which would present a conflict between security and sensitivity in setting the ratios for the breaker CTs.

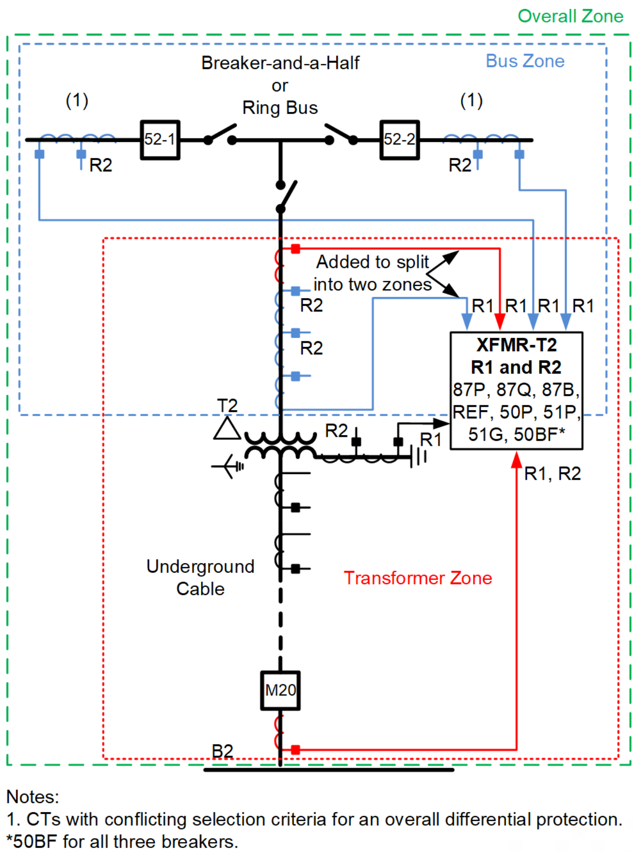

Fig. 6. PNM standard for greenfield bus-tapped power transformer substations using two differential elements.

IV. Protection System

The PNM protection system for distribution substations involves a redundant protection scheme. It has dual active primary multifunction relays from a single manufacturer, which follows the PNM standard for transmission protection systems. According to [6], the unavailability of the dual relay system is ten times lower than that of the single relay system. The advantages of a dual relay system from a single manufacturer include the development of one design, less labor needed for settings, lower incidence of human error, higher settings reliability, lower training cost for inexperienced engineers and technicians, and less complex troubleshooting in the field for any issues that may arise.

The protection system established for the distribution substations of PNM is presented as follows.

A. Line-Tapped Transformers

Fig. 7 shows the standard single-line diagram (SLD) for a brownfield line-tapped delta-wye power transformer protection system with a redundant protection scheme, which includes dual active primary relays, common instrument transformers, a single 48 Vdc control power system, and integrated breaker failure.

Fig. 8 shows the standard SLD of a greenfield line-tapped delta-wye power transformer with added arc-flash protection for individual switchgear compartments and separate CTs for transformer relays (except for the main breaker bushing current transformers) and main breaker relays.

1) Power Transformer Relays

Power transformer relays (XFMR-T1 and XFMR-T2) for brownfield and greenfield substations are equipped with three sets of three-phase current inputs to connect to the delta-side transformer bushing CTs, bus-side main breaker CTs, and transformer neutral bushing CTs. The relays perform the following protection functions.

A phase differential (87P) element provides primary protection for faults inside the transformer tank and for the underground power cable between the power transformer and the main breaker. The percentage differential protection provides a dual-slope characteristic that compensates for steady-state errors, such as transformer magnetizing currents and unmonitored loads, and proportional errors, such as relay measurement errors, CT errors, errors due to a tap changer, and transient errors (i.e., CT saturation). The protection also includes harmonic blocking and restraint features to provide added security during transformer energization or overexcitation conditions. A filtered unrestrained differential element is used because it can operate very quickly for internal faults with higher differential currents.

An REF element provides fast primary protection and detects ground faults for the grounded wye-connected transformer winding, with greater sensitivity to faults near the transformer neutral. This element uses a zero-sequence directional element principle. The REF protection zone is bounded by bus-side main breaker CTs and transformer neutral bushing CTs.

Instantaneous phase overcurrent (50P) elements on the delta side provide backup protection for severe internal faults on the delta winding [6] [7].

Phase overcurrent (51P) elements on the delta side provide backup protection against through-fault damage to transformers. They provide time-delayed backup for 51P elements at the main breaker relays for any fault at the medium-voltage bus and at the underground power cable between the power transformer and the main breaker. They also provide time-delayed backup to differential and sudden-pressure relays that detect internal faults inside the transformer tank.

Ground overcurrent (51G) elements provide backup overcurrent protection for ground faults on the wye side because phase overcurrent elements on the delta side of the transformer are relatively insensitive to these faults.

Underfrequency (81U) elements provide primary protection for abnormal system conditions as required by the PNM underfrequency load-shedding (UFLS) scheme.

Integrated breaker failure (50BF) protection for the high-side circuit switcher or circuit breaker and the low-side main breaker provides faster fault clearing for breaker failure events to mitigate power transformer and equipment damage.

2) Main Breaker Relays

Main breaker relays (Main-10 and Main-20) for brownfield and greenfield substations are equipped with three sets of three-phase current inputs. They are connected to wye-side transformer bushing CTs and tie breaker bushing CTs, as indicated in Section III.A. The third current input is reserved for future and will be connected to the load-side sum of the currents of all feeder breaker bushing CTs. These relays have combined phase and residual overcurrent elements (51P and 51N) that provide primary overcurrent protection for the low-side bus faults and backup overcurrent protection for the feeders. In addition, these relays provide integrated breaker failure protection (50BF) for the main breaker.

Furthermore, these relays can provide bus differential protection (87B) with dual-slope characteristics to protect the medium-voltage bus. The 87B is reserved for future use due to the lack of CTs in the load side of the feeder breakers.

3) AFD Main Breaker Relays

Greenfield substations include AFD in the main breaker relays (AFD-10 and AFD-20). They are equipped with one set of three-phase current inputs to connect to the wye-side transformer bushing CTs. These relays offer combined LS and high-speed phase (50PAF) and/or neutral (50NAF) overcurrent detection for arc-flash events. Four bare-fiber sensors are currently used for arc-flash mitigation, as described in Section III.D. Integrated breaker failure protection (50BF) for the main breaker is also implemented, using these AFD main breaker relays.

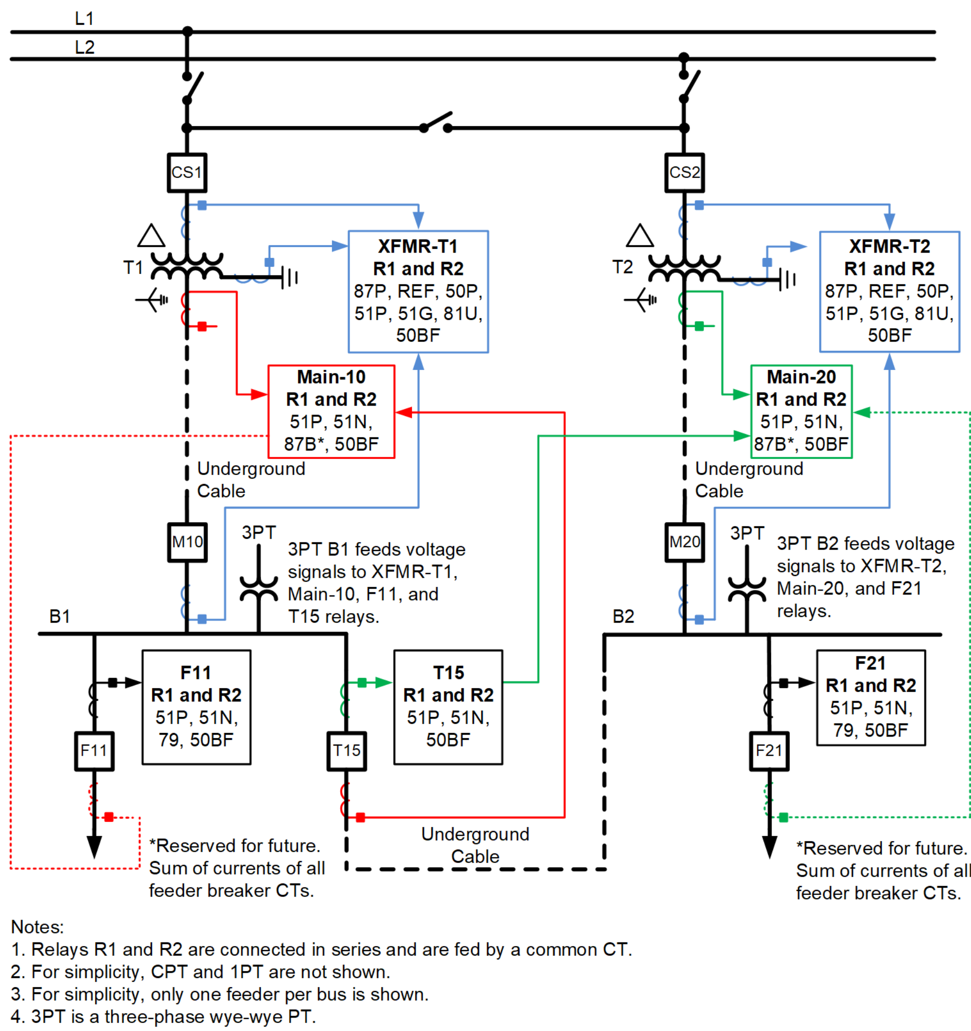

Fig. 7. Protection SLD for a brownfield line-tapped transformer. Existing substations with two transformers have only one tie breaker.

4) Tie Breaker Relays

For brownfield substations, as shown in Fig. 7, these relays (T15) are equipped with three sets of three-phase current inputs. PNM uses the same part number for main and tie relays, reducing the number of spare relays. The first current input is connected to the tie breaker CTs. The second and third current inputs are not used. They have phase and residual overcurrent elements (51P and 51N) to provide primary overcurrent protection for low-side bus (B1 or B2) faults and backup overcurrent protection for feeders that are transferred. In addition, they provide integrated breaker failure protection (50BF) for the tie breaker.

For greenfield substations, tie breaker relays (T15) are equipped with one set of three-phase current inputs to connect to one set of tie breaker CTs. They play the same role as described for brownfield tie breaker relays and have 51P, 51N, and 50BF elements. AFD is also added, using four bare-fiber sensors, as described in Section III.D.

Additionally, for greenfield substations, the adjacent tie breaker relays (T25) are equipped with three sets of three-phase current inputs. Two of them are being used to connect to local tie breaker CTs and to adjacent tie breaker CTs to perform tie bus differential protection with a dual-slope characteristic. This protects the underground power cable between the two tie breakers. They also provide integrated breaker failure protection (50BF) for both tie breakers.

5) AFD Tie Breaker Relays

Greenfield substations include AFD in tie breaker relays (AFD-25), which are equipped with one set of three-phase current inputs to connect with the tie breaker CTs. These relays offer combined light sensors and high-speed phase (50PAF) and/or neutral (50NAF) overcurrent detection for arc-flash events. Section III.D describes the four bare-fiber sensors that are used for arc-flash mitigation. Integrated breaker failure protection (50BF) is also implemented in these relays for the tie breakers.

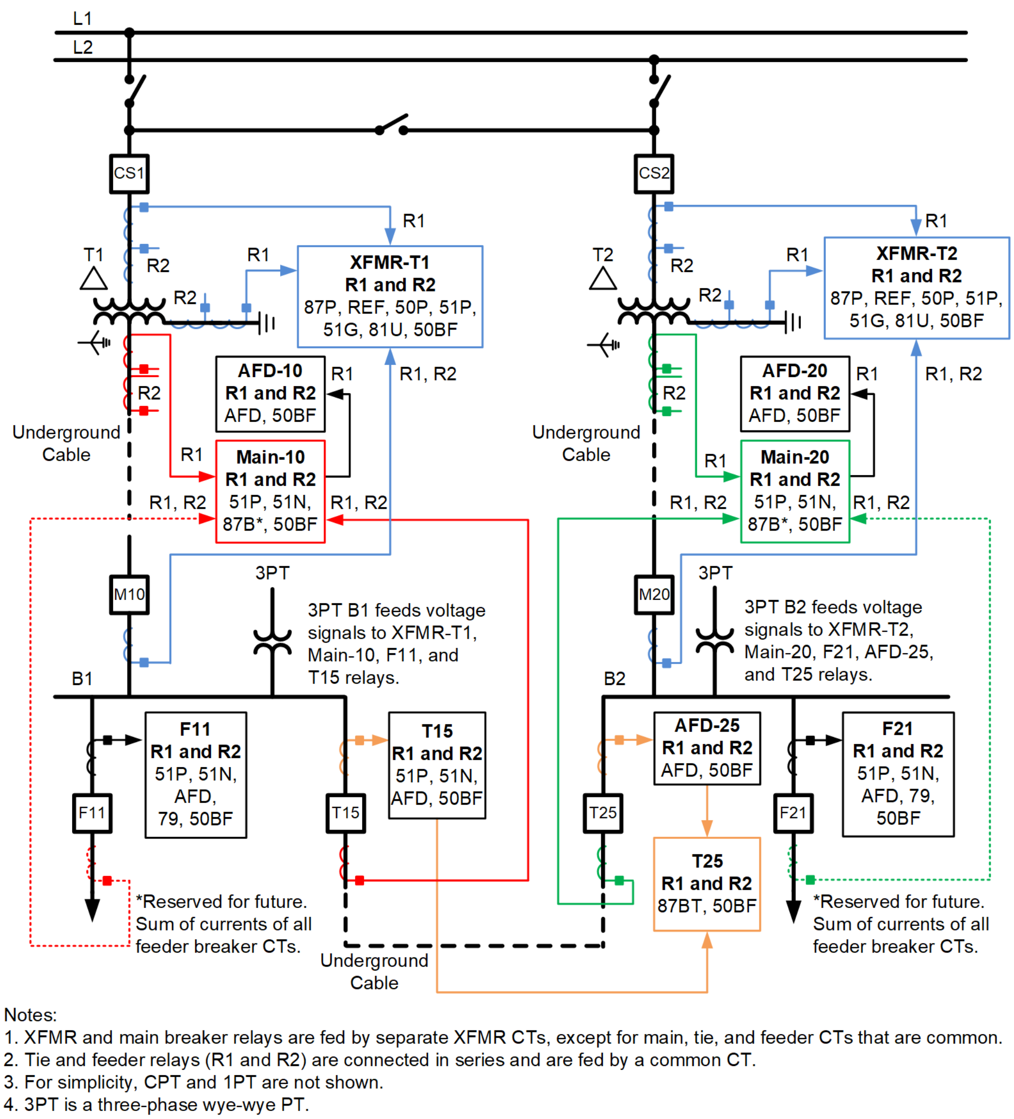

Fig. 8. Protection SLD for greenfield line-tapped transformer. Only one feeder per each bus is shown for simplicity.

6) *Feeder Relays*

In brownfield substations, the feeder relays (F11 and F21) are equipped with one set of three-phase current inputs to connect with their feeder breaker CTs. The feeder relays have phase and residual overcurrent elements (51P and 51N) that provide primary overcurrent protection for the feeder distribution circuits, automatic reclosing (79), and integrated breaker failure protection (50BF).

In greenfield substations, AFD is added by combining an LS with high-speed phase (50PAF) and/or neutral (50NAF) overcurrent elements to detect arc-flash events in each of the feeder switchgear compartments.

B. Bus-Tapped Transformers

At subtransmission substations, bus-tapped transformers are connected either to the bus directly or to one of the bays in a breaker-and-a-half or ring-bus arrangement. Fig. 9 shows the SLD of a standard bus-tapped delta-wye power transformer protection system with a redundant protection scheme, which includes dual active primary relays. It uses a separate current transformer for the transformer relays (except for the main breaker CTs) and main breaker relays. A single 48 Vdc control power system is used for the main, tie, and feeder relays and a single 125 Vdc control system is used for the transformer relays.

In this application, power transformer relays interact with the subtransmission protection system; therefore, PNM uses standardized transformer relays that are different from the transformer relays for line-tapped substations. The relays are installed alongside the subtransmission panels at the transmission control house using 125 Vdc for the power supply and 125/48 Vdc as the control voltage.

Only the elements for the power transformer relays will be described as follows because the functionality of the remaining relays uses the same approach described in Section IV.A for a line-tapped transformer protection system.

Power transformer relays for greenfield substations are equipped with six sets of three-phase current inputs. For transformers with a high-side single-breaker scheme, the transformer relays are connected to the high-side breaker CTs, main breaker CTs, and a transformer neutral CT. In this application, one differential zone is needed. The transformer zone is bounded by high-side breaker CTs and main breaker CTs.

In applications with a high-side dual breaker scheme, as shown in Fig. 9 for Transformer T2, relays are fed by high-side breaker CTs, delta-side transformer CTs, main breaker CTs, and a neutral CT. In this case, there are two distinct zones of protection with different sensitivity and security requirements: the high-side bus zone that is bounded by high-side breaker CTs and delta-side transformer CTs, and the transformer zone that is bounded by delta-side transformer CTs and low-side main breaker CTs.

A phase differential element (87P) for the transformer zone provides primary protection for faults inside the transformer tank and for the underground power cable between the power transformer and the main breaker. Percentage differential protection provides a two-stage adaptive-slope characteristic that improves the sensitivity for internal faults and security for external faults. There are three types of unrestrained differential elements that operate on filtered current samples, raw current samples, or the waveshape of the differential currents. These elements pick up very quickly for internal faults with higher differential currents. The waveshape and raw current unrestrained elements do not require user settings.

A negative-sequence differential element (87Q) provides sensitive primary protection for low-magnitude faults, such as turn-to-turn faults, and is unaffected under normal loading conditions. Sequence component elements cannot be set securely from false unbalanced quantities due to CT saturation by slope alone. Therefore, the element is blocked during external fault detection. There is no second-stage adaptive-slope setting.

The 87 elements provide security for magnetizing inrush current using independent even-harmonic restraint (87P) and common even-harmonic blocking (87P and 87Q). Combining these two methods provides optimal security and speed without sacrificing dependability. Additionally, these elements use waveshape-based inrush detection to improve security from tripping on inrush when the harmonics are low and the waveshape unblocking logic allows a trip if the differential condition is not due to inrush. This is considered for obtaining the best security and speed performance from the 87 elements for internal faults. Furthermore, these elements provide security for overexcitation conditions using independent fifth-harmonic blocking.

A second phase differential element (87B) that offers adaptive-slope percentage-restrained differential protection is used to protect the high-side bus. Inrush detection, overexcitation detection, and negative-sequence differential protection are not needed for the bus zone application.

The REF element provides fast primary protection and detects ground faults for the grounded wye-connected transformer winding, with greater sensitivity to faults near the transformer neutral. This element operates based on the zero-sequence directional principle.

Instantaneous phase overcurrent (50P) elements on the delta side provide backup protection for severe internal faults on the delta winding [6] [7].

Phase overcurrent (51P) elements on the delta side provide backup protection against through-fault damage to the transformers. They provide time-delayed backup for the 51P elements in the main breaker relays for any fault at the medium-voltage bus and at the underground power cable between the power transformer and the main breaker. Also, the 51P elements provide time-delayed backup to differential and sudden-pressure relays that detect internal faults inside the transformer tank.

Ground overcurrent elements (51G) provide backup protection for ground faults on the wye side because phase overcurrent elements on the delta side of the transformer are relatively insensitive to these faults.

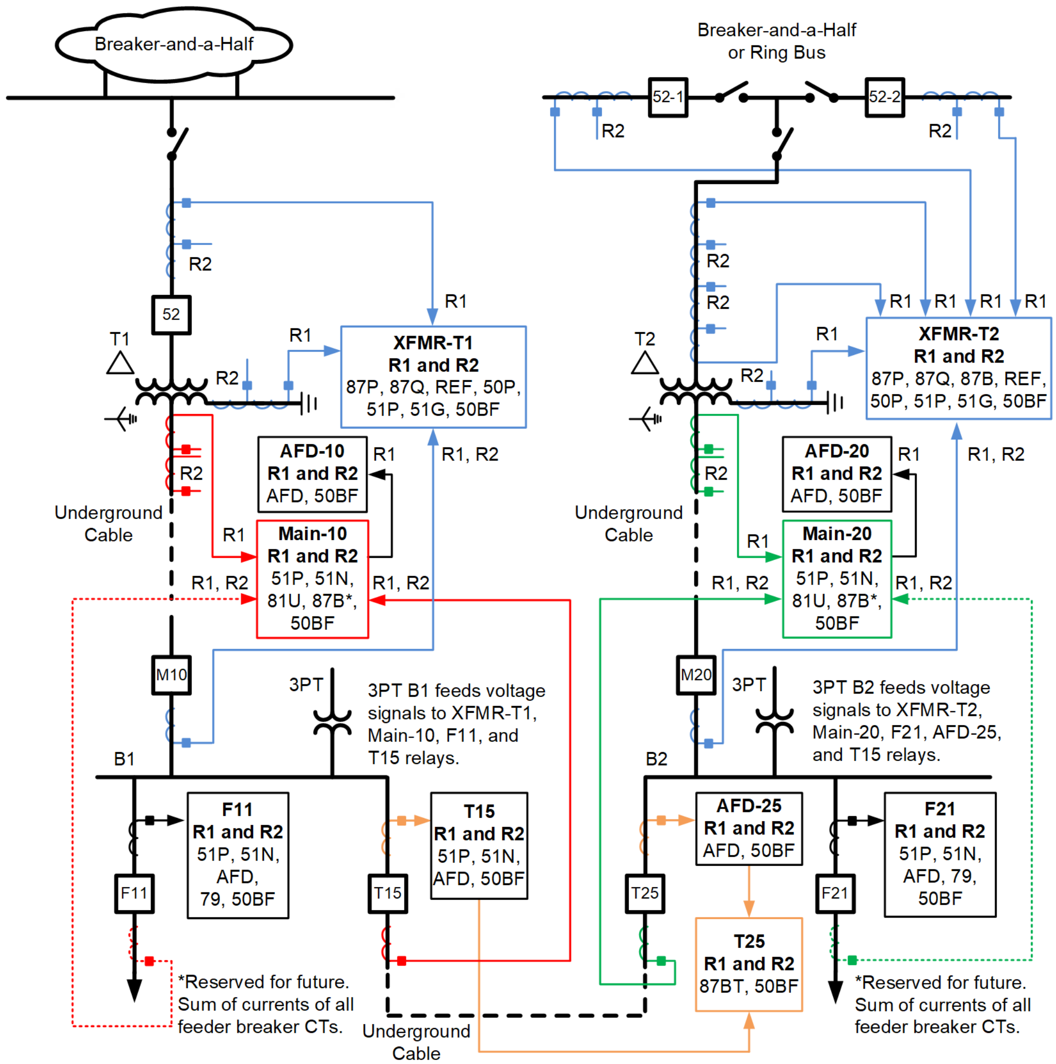

Fig. 9. Protection SLD for greenfield bus-tapped transformer. Only one feeder per bus is shown for simplicity.

Integrated breaker failure protection (50BF) for the high-side circuit breaker(s) and the low-side main breaker provides faster fault clearing for breaker failure conditions to mitigate power transformer and equipment damage.

Because all of the circuitry for the UFLS is installed and wired at the switchgear, the 81U element has been relocated within the main breaker relays. This element provides primary protection for abnormal system conditions as required by the PNM UFLS scheme.

V. Protection Criteria

In this section, the PNM protection criteria that was established for the relay protection upgrade program is described. It serves as a guideline for protection engineers to generate relay protection settings for existing and future distribution substation relays.

A. Line-Tapped Power Transformer Relays

The 87P restrained pickup (O87P) is set to 0.3 per unit (pu) of the transformer base MVA to provide very good sensitivity. To achieve this, it is important to select proper CT ratios and, according to [4], to select an O87P equal to 0.3 pu of the transformer base rating and a relay minimum operating current of 0.5 amperes secondary (for a 5 A relay model), which provides very good sensitivity while allowing a high number of CT turns.

The 87P uses a restraint scaling factor equal to one. The typical Slope 1 set point is equal to 25 percent.

The 87P point of transition to Slope 2 is set higher than normal loading. Using a safety margin factor of two, the typical set point is equal to 5 pu.

Slope 2 does not extend to the origin of the 87P operating versus restraint characteristic. Rather, Slope 2 begins at the restraint point of transition for the slope. The 87P Slope 2 setting is selected to give an effective slope through the origin of the characteristic of approximately 50 percent or higher at the maximum through-fault current, assuming one CT saturates 50 percent [4]. Because the high-side differential zone is bounded by a single breaker, the maximum through-fault current is limited by the transformer impedance and is for a low-side three-phase fault. The typical Slope 2 set point is 60 percent.

Second- and fourth-harmonic blocking and restraint percentage values are set to 15 percent of fundamental. Fifth-harmonic blocking is set to 35 percent.

The 87P unrestrained element pickup is set to the maximum of the transformer inrush current or the maximum through-fault current, accounting for CT saturation. The transformer inrush current is estimated to be eight to ten times that of the base transformer capacity. A low-side three-phase bus fault, which is limited by the transformer impedance and assumes an infinite bus, is considered as the maximum through-fault current. Assuming one CT saturates 50 percent, the spurious operate current is one-half of the maximum bus fault current. The typical set point is equal to 8–10 pu of the base MVA transformer rating.

The REF pickup must be greater than any natural unbalance current caused by load conditions. PNM specifies that the pickup must be greater than the current at 25 percent of the maximum MVA transformer rating. In addition, the pickup must be greater than the minimum value, as determined by the relationship of the current transformer ratio (CTR) values that are used in the REF scheme.

The 50P pickup is set equal to the maximum of the transformer inrush current or 125 percent of the maximum through-fault current generated by a low-side three-phase bus fault that is limited by transformer impedance with an assumed infinite bus.

The 51P pickup is set equal to 220 percent of the base transformer MVA nominal current. The curve characteristic is set to coordinate with the transformer withstand curve. The time dial is set to coordinate with the 51P of the main breaker relays. The coordination time interval (CTI) should be 0.3 seconds or greater for a maximum phase-to-phase low-side bus fault current.

The 51G pickup is set equal to 50 percent of the 51P pickup. The curve characteristic is set to coordinate with the transformer withstand curve. The time dial is set to coordinate with the 51G of the main breaker relays. The CTI should be 0.3 seconds or greater for a maximum single-phase-to-ground low-side bus fault current.

The 81U pickup and the time delay are set based on the PNM UFLS scheme.

The 50BF current detector is set as sensitive as possible to detect minimum breaker currents. This philosophy biases the breaker failure scheme towards dependability in accordance with the PNM standard. The PNM typical set point for distribution relays is 0.1 amperes secondary. The 50BF time delay is set at 0.2 seconds.

B. Main Breaker Relays

The 51P pickup is set equal to 200 percent of the base transformer MVA nominal current. The curve characteristic is set to coordinate with the 51P curves on the transformer and feeder relays. The time dial is set to coordinate with 51P at the feeder relays. The CTI should be 0.3 seconds or greater for the maximum of the three-phase or single-phase-to-ground low-side bus fault current.

The 51N pickup is set equal to 40 percent of the 51P pickup. The curve characteristic is set to coordinate with the 51G curves on the transformer and feeder relays. The time dial is set to coordinate 51N with the feeder relays. The CTI should be 0.3 seconds or greater for the single-phase-to-ground low-side bus fault current.

The O87B is set to 1 pu of the bus current rating. The main breaker relay uses a restraint scaling factor equal to one. Thus, the typical Slope 1 set point is equal to 60 percent. The 87B point of transition to Slope 2 is set above that of normal loading. Using a safety margin factor of 1.5, the typical slope transition set point is equal to 3 pu. The 87B Slope 2 is set to obtain an effective slope of approximately 50 percent or higher at the maximum through-fault current, assuming one CT saturates at 50 percent [4]. The typical Slope 2 set point is equal to 80 percent.

C. AFD Main Breaker Relays

The 50PAF pickup is set to two times that of the maximum transformer MVA and the 50NAF pickup is set to two times that of the 51N pickup of the main breaker relays. The arc-flash LS pickup should be higher than the maximum ambient light levels in the switchgear location; therefore, the value is set to 3 percent for all four bare-fiber sensors as a starting value and tested during commissioning.

D. Tie Breaker Relays

The 51P pickup is set identically to the 51P pickup at the main breaker relays. The curve characteristic is set to coordinate with the 51P curve of the transformer and adjacent feeder relays. The time dial is set to coordinate with 51P of the adjacent feeder relays. The CTI should be 0.3 seconds or greater for the maximum of the three-phase or single-phase-to-ground low-side bus fault current.

The 51N pickup is set equal to 40 percent of the 51P pickup. The curve characteristic is set to coordinate with the 51G curves of the transformer relays and the 51N curve on adjacent feeder relays. The time dial is set to coordinate with 51N of the adjacent feeder relays. The CTI should be 0.3 seconds or greater for the single-phase-to-ground low-side bus fault current.

The 87B element is set by following the same procedure described for the main breaker relays.

E. AFD Tie Breaker Relays

The 50PAF pickup is set to two times that of the maximum transformer MVA and the 50NAF pickup is set to two times that of the 51N pickup of the tie breaker relays. The arc-flash LS pickup should be greater than the maximum ambient light levels in the switchgear location; therefore, it is set to 3 percent for all four bare-fiber sensors as a starting value and tested during commissioning.

F. Feeder Relays

The 51P pickup is set according to the PNM planning studies. The typical values are 600 and 720 amperes primary. The curve characteristic is set to coordinate with the 51P curve of either the main breaker or the tie breaker relays. The time dial is set to operate at 0.3 seconds or higher for the maximum close-in fault current (three-phase or single-phase-to-ground fault) to coordinate with the downstream protective devices.

The 51N pickup is set equal to 360 or 480 amperes primary. The curve characteristic is set to coordinate with the 51N curve of either the main breaker or the tie breaker relays. The time dial is set to operate at 0.3 seconds or higher for the maximum single-phase-to-ground close-in fault current to coordinate with the downstream protective devices, such as fuses or reclosers.

The 50PAF pickup is set to two times the 51P pickup and the 50NAF pickup is set to two times the 51N pickup. The arc-flash LS pickup should be higher than the maximum ambient light levels in the switchgear location; therefore, it is set to 3 percent as a starting value and tested during commissioning.

VI. Engineering Design Package

PNM has established standard documents to expedite the EDP to be used during relay protection upgrades for brownfield substations. These standard documents include:

- Protection system
- Protection criteria
- Retrofit plates issued-for-construction (IFC) drawings
- Relay settings calculation templates
- Relay settings configuration templates
- Relay settings summary template

For greenfield projects, these standard documents are also used, except for the retrofit plates IFC drawings. Furthermore, the input/output (I/O) table for each relay has been standardized by PNM and those are provided to the switchgear manufacturer to generate the IFC drawings.

The following documents that are part of the EDP are created based on standard documents for each project:

- Demolition (Demo) drawings
- Installation (Install) drawings
- Protection criteria
- Relay settings calculations sheet
- Relay settings configuration files
- Relay settings summary

PNM plans its projects one year ahead of time to schedule material and equipment procurement, create the IFC EDP, and determine the commissioning time frame. Therefore, material, equipment, and the IFC EDP will be ready, allowing commissioning to be executed during an outage window. Commissioning is discussed in Section VII.

A. Drawings

PNM engineering design focuses on using modern microprocessor relays to achieve the desired protection system, as described in Section IV. The design entails a dedicated power supply circuit for each relay, direct tripping of breakers via relay outputs, executing SCADA commands via relay outputs, and using optoisolated inputs to monitor statuses and alarms. As previously mentioned, PNM has designed and standardized the retrofit plates to upgrade brownfield switchgear (as shown in Fig. 10), including the following types:

- Transformer for Unit 1
- Main breaker for Unit 2
- Feeder breaker for Units 3 through 6
- Tie breaker for Unit 7

Each type is documented with the following drawings: panel elevation, bill of materials, equipment nameplate, ac schematics, dc schematics, and SLD. PNM uses the standard retrofit plates to incorporate them into the project-specific drawings package. For a brownfield project execution, two sets of drawings are prepared: Demo and Install drawings. These drawing markups are color-coded according to the PNM drawing standards to denote the demolition and installation of wires, cables, and equipment.

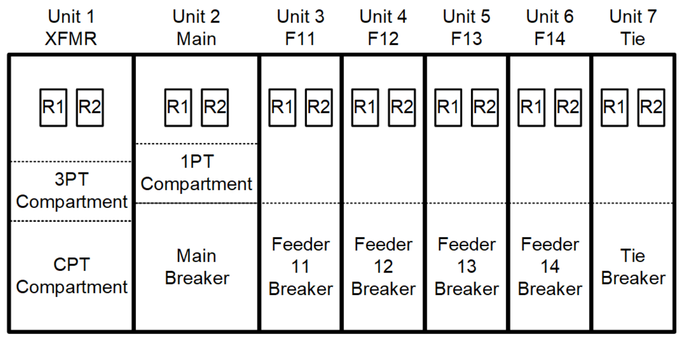

Fig. 10. Simplified switchgear front view of the relay doors.

B. Settings Calculations

Based on the standard protection criteria described in Section V, PNM has developed relay settings calculation templates using engineering calculations software. As part of the settings standardization process, these templates are established for every application: transformer, main breaker, main breaker AFD, tie breaker, tie breaker AFD, and feeder relays. Additionally, relay settings calculation templates include detailed documentation regarding the logic settings that have been tested in the laboratory and the field. Furthermore, PNM has an internal process to keep its transmission and subtransmission network modeled and updated in a PC-based short-circuit and relay coordination program. This software is used to model the distribution substation and run short-circuit and protective device coordination studies.

The PC-based software and the relay settings calculation templates assist the settings engineer in expediting the relay settings calculation sheets and relay settings summary for each project. However, the settings engineer must be aware that no tool can take the place of good engineering judgement. Protection criteria and relay settings calculation templates not only serve as an engineering guide for beginning engineers, but also assist in expediting the learning curve on best practices in the industry.

C. Relay Settings

PNM has standardized relay settings configuration files as templates for each application based on the protection criteria, retrofit plates IFC drawings, and relay settings calculation standard documents. PNM uses PC-based software as a tool for engineers and technicians to configure, commission, and manage relay settings configuration files quickly and easily. These files standardize protection, logic, front-panel, report, and communication settings. The settings engineer uses these standard configuration files to create the project-specific files.

VII. Commissioning

On brownfield projects, PNM performs the relay protection upgrade under de-energized system conditions. Therefore, following the PNM safe work practices, primary isolation is executed to de-energize the power transformer and switchgear.

PNM has a detailed procedure for commissioning protection relay packages. This procedure provides the requirements for commissioning protective relays and includes the following activities for brownfield distribution substations:

- Visual and physical inspection
- Secondary injection
- Logic and functional testing
- Pre-energization
- In-service readings

All of these activities are documented in PNM standard forms, according to the PNM commissioning procedure.

A. Visual and Physical Inspection

PNM performs panel or switchgear visual inspection for any noticeable problems with all of the wiring and the working conditions of its associated components. As part of the visual and physical inspection, the following checks are executed:

- Verify that the dc battery system operating voltage is correct.
- Confirm the absence of outstanding alarms on battery charger.
- Inspect the relays, panels, and other equipment for physical damage.
- Verify that relay chassis and panels are grounded.
- Confirm that shields are properly grounded.
- Verify the polarity connection on CTs and relays.
- Ensure that visible and correct labels are on wires, cables, and panels.
- Verify correct crimping on wire and cable terminations.
- Inspect the tightness of all terminals with appropriate torque ratings.
- Confirm correct fuse sizes and ratings.

B. Secondary Injection

PNM performs secondary injection to verify the wiring of CTs and PTs. The secondary injection is performed from the first terminal block where either the CTs or PTs are terminated. PNM uses the relay software to assist with and document the secondary injection.

Fig. 11 shows the results of secondary injection from the terminal blocks for the high-side transformer CTs and the low-side bus PTs into the transformer relay.

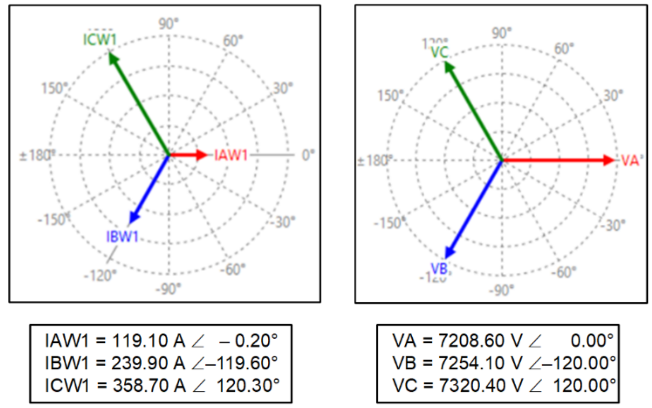

Fig. 11. Transformer relay measurement for CTs and PTs secondary injection.

Fig. 12 shows the secondary injection for transformer neutral CTs, using signals from low-voltage bus PTs as reference.

In addition, the commissioning engineer blue highlights the drawings as the circuits are being field verified and tested. Lastly, PNM field personnel verify the single point of grounding on CT circuits and double-check that the PT ratios and CT ratios match those on the drawings and in the settings configuration files.

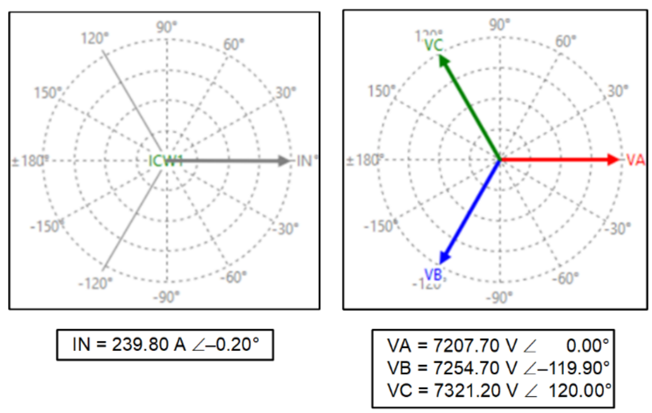

Fig. 12. Transformer relay measurement for transformer neutral CT secondary injection.

C. Logic and Functional Testing

The PNM procedure to perform logic and functional testing includes relay calibration, testing and logic, and functional testing.

As part of the relay calibration testing, the commissioning engineer uses test plans that have been developed in the laboratory by PNM to test all of the protection elements. For logic and functional testing, the commissioning engineer blue highlights the drawings as the circuits are being field verified. The commissioning engineers are responsible for testing:

- All inputs for statuses and alarms, verifying their acknowledgement in the relay software.
- All outputs for trip and alarm signals, checking their operation according to the protection and control system.
- Alarms and analog values sent to SCADA.

- All parallel paths from the dc source to the interrupting device (close and trip coil).
- LOR trip and block close according to the drawings.
- Transformer trips and alarms sent to the relays and SCADA.
- Trip circuit monitor circuits.

For automatic reclosing, arc-flash, and breaker failure testing, PNM runs a test plan and captures the Sequential Events Recorder (SER) report and event report. Using these reports, the commissioning engineer verifies the correct sequence of operation.

D. Pre-Energization

PNM performs a walk-down before re-energizing the substation. The following list shows the checks included during the walk-down:

- Review all testing documents and drawings for completeness.
- Confirm that protective grounds have been removed.
- Verify that all main circuit breakers and fuses are restored back to normal.
- Verify that all test switches are closed.
- Verify that all control switches (43) are set to normal.
- Verify that there are no standing alarms.
- Verify that no dc grounds are present.
- Verify that all relay protection has been fully restored.
- Verify that the relay passwords have been changed.
- Confirm that CT ratios and polarities are correctly connected.
- Verify that there are no shorting screws for CT circuits in service.
- Verify that unused CTs are shorted to ground.

E. In-Service Readings

PNM performs in-service readings on the day of energization and between 24 and 48 hours after initial energization. The in-service readings include screen captures of relay phasors, instantaneous metering, and differential metering from the relay PC-based software. As part of the in-service reading checks, the commissioning engineer verifies that there are no standing alarms, warnings, or errors in the relays and that there are no chattering signals in the SER reports for the relays.

Fig. 13 shows an example of differential metering values once the distribution substation is re-energized and the transformer is loaded.

All screenshots and checks should be documented using the in-service reading form.

Differential Metering Values

XMFR-T1 R1 Date: 03/15/2024 Time: 12:54:46.787
LA MORADA Time Source: Internal

Operate	(pu)	IOP1 0.00	IOP2 0.00	IOP3 0.00
Restraint	(pu)	IRT1 0.39	IRT2 0.38	IRT3 0.38
2nd Harmonic	(%)	IOP1F2 0.00	IOP2F2 0.00	IOP3F2 0.00
4th Harmonic	(%)	IOP1F4 0.00	IOP2F4 0.00	IOP3F4 0.00
5th Harmonic	(%)	IOP1F5 0.00	IOP2F5 0.00	IOP3F5 0.00

Fig. 13. In-service readings of differential metering values for transformer relay.

F. Troubleshooting Using Event Analysis

One of the PNM distribution substations, Camel Tracks, has a single line-tapped 8.4/10.5 MVA power transformer that is connected to one 46 kV subtransmission line and three distribution feeders at 12.47 kV levels. Fig. 14 shows a simplified protection SLD of the Camel Tracks substation, with the protection system upgraded in October 2021. On August 16, 2023, at approximately 15:00 hrs, a B-phase-to-ground (BG) fault occurred downstream of Feeder 13 during a storm and while the power transformer was carrying a light load. This fault triggered the REF element of the microprocessor-based transformer Relays R1 and R2 to trip incorrectly and open the high-side Circuit Switcher CS and Main Breaker M10.

Feeder relays (F13 R1 and F13 R2) recorded this fault event, showing that the 51N element picked up for a BG fault current of 2270 amperes and reset in approximately 0.063 seconds. Note that the 51N operating time for this level of current is 0.378 seconds according to the relay programming.

In addition, the transformer relays (XFMR-T1 R1 and XFMR-T1 R2) recorded the fault event and registered a BG fault current magnitude of 2273 amperes. Its 51G element picked up and reset in approximately 0.058 seconds. The 51G operating time for this level of current is 2.165 seconds according to the relay programming. Nevertheless, the REF element on the transformer relays (XFMR-T1 R1 and XFMR-T1 R2) had ultimately tripped.

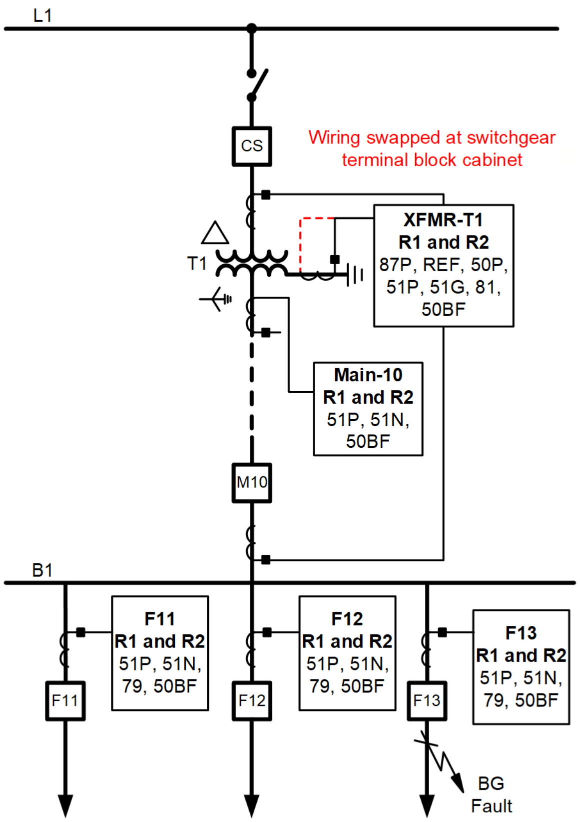

Fig. 14. BG fault on Feeder 13 at Camel Tracks substation.

After performing the event analysis, it was discovered that the transformer relays were fed by neutral CTs that had swapped connections. Fig. 15 shows that the neutral operating current from the neutral CT and the residual polarizing current from the main breaker CTs are equal in magnitude and in phase, which is not desirable. The correct way is that they should be equal in magnitude and 180 degrees out of phase.

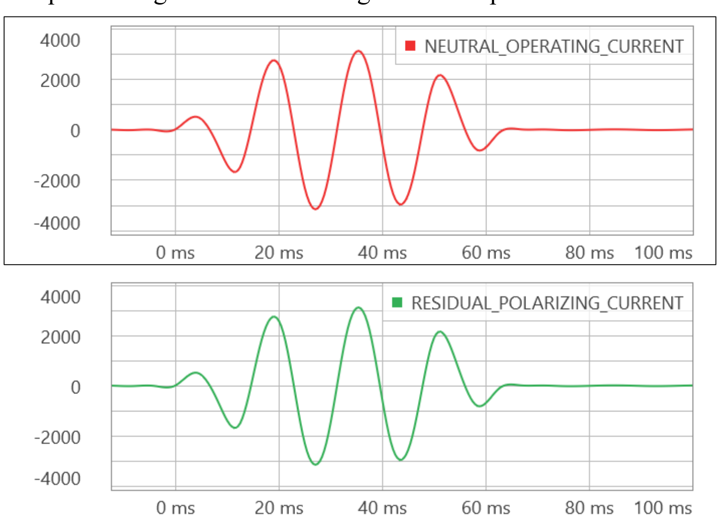

Fig. 15. Neutral operating current and residual polarizing current in phase because of swapped wiring at the switchgear terminal block cabinet.

The phasing of the main breaker CT currents was double-checked by a comparison with the high-side transformer CT currents; the non-operation of the 87P element was confirmed for this external fault. PNM field crews found that the two wires were rolled incorrectly in the switchgear terminal block cabinet and confirmed the validity of the results from the observed event report.

VIII. Conclusion

PNM deployed a proactive approach to be prepared with resource requirements, procurement needs, and budget plans, among other issues, as they strive to upgrade their distribution protection infrastructure. The relay upgrade program, using reliable and dependable microprocessor-based relays in addition to standardized EDP, has helped PNM to fully eliminate the exposure in their existing distribution protection system. The five-year program allowed PNM to upgrade 38 brownfield distribution substations, which includes 43 indoor metal-clad switchgear. Furthermore, the lessons learned and documentation of this program have been extended to commission an additional six greenfield substations, which include eight indoor metal-clad switchgear.

Fig. 16 depicts the summary of brownfield and greenfield protection schemes that have been commissioned from 2020 to present. PNM has commissioned 317 protection schemes and 650 protection relays, so far. In addition, the figure shows the number of modern microprocessor relays that have been used to upgrade their obsolete relays.

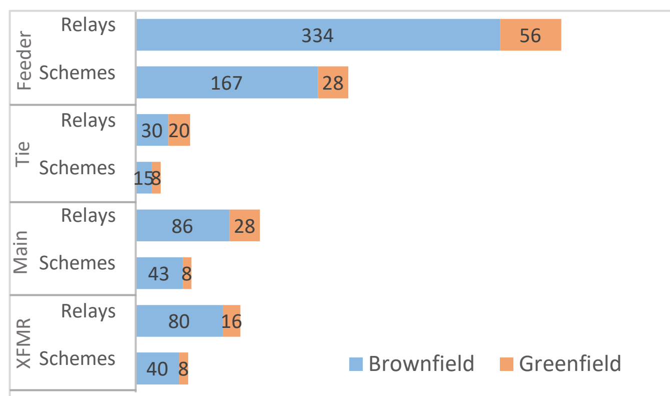

Fig. 16. Summary of protection upgrade program.

This cumulative effort has established the standard baseline for all documents described in this paper and serves as a guideline for beginning engineers to expedite the learning curve on the best practices for the industry. In addition, reduced labor for settings development, a decreased incidence of human error, increased system reliability, lower training cost for inexperienced engineers and technicians, and less complex troubleshooting in the field are some of the added benefits that PNM achieved by instituting the upgrade program. Furthermore, using all of the tools available, including event report analysis after the upgraded protection system is in service, PNM can work towards establishing the process of constant improvement in their projects.

PNM is looking forward to upgrading the next set of brownfield substations in their short-term planning using these modern protection and control solutions. The features explained in the paper are available in modern microprocessor relays and should be put to use to improve the protection system.

The settings upgrade process outlined in this paper can be extended to similar distribution substations. The settings engineer should be mindful of devising a dependable, secure, and reliable protection and control scheme. With the dynamics that the power grid has been constantly facing, protection engineering should also be equally modernized and flexible enough to accommodate rapid changes. Thus, modern relays, with advanced technologies and better communication capabilities, can replace the conventional protection schemes and offer a robust solution to utilities and customers.

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X. Biographies

Crescencio Miguel Montero Jr. received his Associate of Applied Science Degree in Engineering Technology Electronics from Luna Vocational-Technical Institute, Las Vegas, NM, in 1998. He received his B.S. in Science and Engineering Technology Electronics from New Mexico State University in Las Cruces, NM, in 2001. From 2001 through 2011, he worked as Protection and Control (P&C) technician senior for Oncor Dallas Transmission, Dallas, TX. As a P&C technician, he performed relay protection maintenance (electromechanical, solid state, and microprocessor) on both transmission and distribution stations throughout the Dallas metroplex. He also commissioned protection, metering, and supervisory control and data acquisition (SCADA) systems, as well as installing and commissioning various retrofit line packages throughout the metroplex area. In 2011, he was hired as relay journeyman for Public Service Company of New Mexico (PNM). After 6 months, he became the PNM relay supervisor. As a relay supervisor, he was recognized as a subject matter expert (SME) in North American Electric Reliability Corporation (NERC) Standard PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance and PNM's New Mexico Operations (NMOPS). He also co-authored PNM's PRC-005-6, "Relay Maintenance and dc Functional Testing." He is also recognized as an SME for PRC-006 and PRC-027. From 2019 to present, Crescencio is Protection Engineer IV in which he supports both distribution and transmission systems with regards to operation and management, as well as supporting capital projects.

Santiago Bemjamin Sena received his M.S.E.E. and B.S.E.E. from the University of New Mexico (UNM). Santiago has worked for the Public Service Company of New Mexico (PNM) for ten years. He has served in multiple positions including as a rotational engineer for two years, a distribution planning engineer for eight years, and a distribution protection engineer for two years.

Chelsea Collette received her B.S.E.C.E. degree from Oregon State University (OSU). Chelsea worked at Pacific Gas & Electric Company (PG&E) for approximately five years. She held a variety of roles, ending with protection engineering for her final two years at the company. Chelsea then moved to Public Service Company of New Mexico (PNM) and has been working in protection engineering for the past four years. Chelsea has served as a protection engineer for 2.5 years and as manager of the team for 1.5 years.

Eliseo Alcázar Ramírez received his M.S.E.E. from Autonomous University of San Luis Potosí in 2015 and his B.S.E.E. degree from the Oaxaca Technological Institute in 1998. Upon graduating with his B.S.E.E., he served five years at Comisión Federal de Electricidad (CFE) in Mexico, at the Southeastern Distribution Division (SDD). Working with CFE, he was involved in developing supervision, maintenance, installation, and commissioning of protection, control, and metering systems. In April 2004, Eliseo joined Schweitzer Engineering Laboratories, Inc. (SEL). He is presently a senior engineer at SEL Engineering Services, Inc (SEL ES). His professional experience includes devising solutions and performing studies for industrial, distribution, transmission, renewable and conventional generation, and special protection systems such as remedial action schemes and microgrids. He has commissioned protection, control, metering, and supervision systems, and also remedial action schemes. He is a senior member of IEEE.

Srinath Shankar received his B.E.E.E. from Anna University, India, in 2017 and his M.S.E.E. degree from North Carolina State University (NC State) in 2021. Srinath complemented his graduate coursework with cooperative education at Siemens for approximately 1.5 years in their low-voltage motor control center division. Upon graduating from NC State, Srinath joined Schweitzer Engineering Laboratories, Inc. (SEL) and has been working as a protection engineer for approximately three years at SEL Engineering Services, Inc. (SEL ES) in Boise, ID. His professional experience includes distribution, generation, and industrial protection engineering; power system studies; and renewable system design. He is a registered engineering intern (E.I.) in the state of Idaho.

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