Automatic Reconfiguration of Zones for Three-Phase and Spare Banks

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***Abstract*—In 2006, AEP announced the I-765 project to add significant EHV (extra-high-voltage) transmission paths to the eastern interconnected grid. One of the stated goals of I-765 was to apply advanced technology to the design of the next generation EHV transmission systems. The systems must be designed to maximize service continuity because loss of any new transmission assets would have a severe impact on power transfer limits and stability margins throughout the system. This paper focuses on one of the many applications of modern protection and control system technology associated with this project.**

EHV transformer and reactor installations use single-phase tanks because of the large size and weight of the equipment. To improve fault tolerance of the bulk power system, a fourth spare tank is often installed. However, in the past, the spare could only be utilized after the buswork and the protection, control, alarm, and measurement functions were rewired and checked, resulting in a prolonged outage of the bank. Further, because of the work involved to insert a spare, it often sat idle for many years before being called upon for service. At that point, the spare may no longer be reliable. This paper reports on the AEP investigation of how modern protection and control technology can make it possible to design an installation so that a critical bulk power system asset can be restored in hours instead of weeks, months, or years after a failure. The results of this investigation caused the authors to conclude that using single-phase tanks in a three-phase and spare configuration can have an impact on system planning for all levels of the bulk power system—not just EHV.

I. Introduction

American Electric Power (AEP) operates the largest 765 kV transmission network in North America. In 2006, AEP announced the I-765 project to add significant EHV (extra-high-voltage) transmission paths to the eastern interconnected grid. The planned projects will remove transmission bottlenecks and improve the robustness of the synchronous network. One of the stated goals of I-765 is to apply advanced technology to the design of the next generation EHV transmission systems.

The AEP protection and control engineering group is taking this opportunity to develop its next generation of protection and control system standards. Many of the concepts and technologies developed for EHV application will find their way into standards for protection and control at all levels of the bulk electric power system. The AEP next generation of standards now under development must be forward-looking to anticipate and exceed regulatory requirements for operation, maintenance, and reliability. Another goal is for the new standards to have a design life of at least ten years, so they must balance the use of cutting edge technology with mitigation of risk from unproven technology.

One of the requirements is to improve fault tolerance of the major assets to improve their overall availability. Major equipment such as transformer banks and shunt reactor banks represent extremely expensive devices with long lead times. The size of the equipment required for EHV applications means that repair or replacement projects take a great deal of planning and time. For this reason, system planning engineers must often consider overbuilding facilities to deal with extended outages. If the expected outage times can be reduced to hours instead of weeks, months, or years, the cost of building new bulk power system facilities can be significantly reduced.

To achieve the desired reduction in outage times, AEP is planning to build future EHV transformer and reactor banks with in-place spares that include switching apparatus to allow easy substitution of a spare to restore a bank to service in hours instead of weeks. This plan requires that the protection and control systems be designed so that they can automatically reconfigure the zones of protection for any possible configuration, without requiring wiring changes and testing prior to restoring a bank to service. Further, if the protection and control systems can provide positive identification of the faulted equipment in the zone without requiring time-consuming testing of the apparatus, repair or reconfiguration times can be significantly reduced.

One of the design inspirations is to make it so easy to substitute a spare that it may become standard practice to switch the bank configuration quarterly (i.e., the spare is idle for three months, substituted to A-phase for three months, etc.). With regular operational practice, restoration of a critical bank after a failure could be accomplished in hours instead of weeks. This paper describes the AEP investigation into how modern protection technology can be used to automatically reconfigure the protection system zones for transformer and reactor banks, making these plans possible.

II. Background

A. AEP Practices With EHV Transformer and Reactor Banks

The AEP 765 kV system was primarily built in the late 1960s through the late 1970s. Single-phase tanks were used at this voltage level because of the large size of the equipment. AEP had spares for both transformers and reactors. The 765 kV power grid had a new and exciting feel in those times but had to design all protection, control, and alarm functions using electromechanical or static devices.

1) Transformer Banks

AEP has approximately 110 single-phase EHV transformers connected to the 765 kV system. Single-phase units with low-side voltages of 500 kV and 345 kV range in rating from 500 MVA to 750 MVA. Units with low-side voltage of 138 kV are rated 250 MVA. Typically, these units have 34.5 kV tertiary windings. The tertiary windings are externally connected in delta using a number of cables in parallel. The cables are sized to handle the sometimes large 3I0 circulating currents in part because of system unbalances from nontransposed lines, a varying number of reactors connected per phase, and transformer impedance unbalances. AEP relies on the tertiary winding connections for station service, neutral winding stabilization, limiting resonance conditions, 3I0 ground current contributions for faults, and polarization.

A spare transformer is often available to replace a failed unit. But it is not easily switchable. When a spare is present at the station, it requires much physical bus and protection and control system wiring work to connect it in place of the failed unit. In addition to the high- and low-side bus connections, the tertiary winding must be cabled into the delta connection. The current transformer (CT), transformer cooling, and protection schemes must also be reconnected, and the reconfigured relay schemes must be trip-tested. It takes three to four weeks to substitute a spare transformer or reactor into a bank. Also, even though maintenance was done on spare primary equipment, sometimes after years of sitting out of service, the spare would not pass all the necessary tests for being utilized.

Insulation power factor and oil testing are two examples of tests required on a spare before utilizing it in a three-phase bank.

2) Reactor Banks

AEP has approximately 130 single-phase and 5 three-phase oil-immersed shunt reactors. The single-phase 765 kV reactors range in size between 50 and 100 MVAR, with 100 MVAR as the current standard. Three-phase reactors are applied at 345 kV and below and are typically 100 MVAR. The single-phase, 765 kV, 100 MVAR reactor has an impedance of 1,950 ohms, with a saturated reactance of 25 percent of the unsaturated reactance. The single-phase reactors are connected at one or both ends of long transmission lines. The reactors are wye-connected with a solidly connected neutral, except for lines operated in a single-pole tripping/reclosing (SPT/SPR) mode.

For lines with SPT/SPR, a neutral reactor is installed. This fourth reactor is 20 MVAR, 138 kV class, with an impedance that varies by application. The neutral reactor is connected between the common connection of the three individual reactors and ground. This reactor is installed to suppress the secondary arc current on the faulted phase induced by the remaining two energized phases. A spare neutral reactor is also installed to expedite replacement. However, this spare would require oil tests, physical switching, and protection and control system wiring work before it can be energized. A spare neutral reactor is also located at selected stations and at those with SPT/SPR. The spare may need to be relocated along with the physical bus and always requires protection and control system wiring work.

3) Looking to the Future

In 2010 and beyond, the 765 kV power grid has a totally different purpose. It is being expanded under totally different circumstances. The old monopoly grid is being transformed into the national grid with a competitive national goal based on the 2005 energy legislation, NERC (North American Electric Reliability Corporation) reliability standards, and a host of other pressures. In response to this background, the standard applied to these new 765 kV projects must utilize the spare equipment much more effectively.

This paper describes how to design the protection, control, and alarming requirements using advanced microprocessor-based protection and control devices that redundantly and independently meet or even exceed the NERC reliability standard requirements.

A critical component for an effective use of a spare transformer tank is the design of a protective system that supports the substitution of the spare transformer tank in either one of the two three-phase transformer banks with only operator switching time delay.

The three-legged bus reactor and spare will be protected so that from initial installation any three out of the four tanks can be utilized to configure a three-phase reactor bank with only operator switching time delay. Finally, the line reactor bank supporting SPT/SPR, referred to as the four-legged reactor, will have the same protection system requirements as above for the bus reactors. The protection system will support utilization of either the neutral or spare neutral reactor in the four-legged reactor bank with only operator switching time delay.

B. Motivation for Change

The motivations for developing protection systems that can maximize the utilization of spare equipment are as follows:

- Increased system reliability requires fast spare equipment substitution or replacement of failed equipment.
- The line reactor bank, which is integral to successful secondary arc extinction, must be re-established quickly so the line can be operated in SPT/SPR mode.
- The transformer banks are critical to the power transfer from the 765 kV to the 500 kV grid backbone. It is paramount to re-establish the three-phase banks following a failure with only operator switching time delay.
- The NERC reliability standards provide requirements from monitoring to maintenance and everything in between.
- Anticipate forthcoming NERC reliability standards so that the protection design of these new critical assets stands the test of time.
- All new 765 kV lines will be constructed to include fiber communications and utilize SPT/SPR. This style of construction takes advantage of the flexibility provided in today’s modern microprocessor-based

protection systems. The four-legged reactor is necessary to support the SPT/SPR requirement, while the transformers are needed to transform the power to the existing 500 kV portion of the power system.

- The economics of these proposed new 765 kV projects for modernizing the power grid require many functions that were not possible when the original 765 kV grid was built. Taking advantage of each function available in modern devices provides real value for these 765 kV projects or any EHV power grid development. AEP anticipates these concepts being available for all lower-voltage projects through the creation of AEP's next generation of standards.
- The concept of always using three-phase transformer banks at lower voltages may need to be reconsidered in light of the new protection concepts established in this paper. The three-phase transformer bank is limited by size and weight. Planning for the loss of a three-phase bank, in many cases, requires an installed, parallel three-phase bank because of the long time it takes to replace transformers. Rapidly replaceable, single-phase tanks may be a much more economical choice in the future.

C. *General Requirements*

The investment in building any EHV project requires that the new facilities have high availability. High availability requires that the spare equipment be interchangeable. Therefore, major components like transformers, reactors, and breakers must all have the same requirements. The protection systems must clear faults rapidly, dependably, and securely. This requires careful protection scheme development that covers every fault possibility with sensitivity and speed, resulting in reliability of both the protection system and power grid simultaneously.

Some goals of the new protection and control standard, are:

- Take human performance issues (HPI) into account:
  - Switch the banks in or out of service (or substitute a phase tank with the spare) in the relays, with pauses for visual verification of proper switch opening or closing before progressing to the next switching sequence item.
  - Verify that the protection system matches the physical bank configuration prior to energizing.
  - Monitor the protection systems so that problems can be determined to minimize analysis and repair time.
  - Arrange the test switches so that repairs can be made while the transformer or reactor bank remains in service or can be reconfigured if the problem exists within only one tank in the bank.
- The above items are supported by the main items that any good protection system should exhibit, which include:
  - Provide redundancy for all types of fault conditions from battery through required protection and control devices, paths, sensing, tripping, etc.
  - Apply redundant functions in two independent schemes that cover all present and forthcoming NERC reliability standard requirements.
  - Design the protection systems to allow maintenance work on one system while the transformer or reactor remains in service and fully protected by only one protection scheme for all types of faults, without loss of sensitivity or reliability.
  - Provide proper targeting, even with the substitution of the spare tank to any phase.
  - Provided adequate transformer or reactor monitoring so that overloads and fault occurrences can be tracked on a per-tank basis.
- Pursue "maintenance free schemes" with the "fully monitored" opportunity available in the revision to the NERC PRC-005 Maintenance Standard [1][2].

III. Transformer Protection

A. *Present Protection Practices*

Two battery systems are used with redundant protection systems on each battery. All EHV transformers have at least three methods of protection. These methods include harmonic restrained differentials, fault pressure, and overcurrent (both time and instantaneous).

The differential protection is configured so that the transformer and lead bus always have two different vendor relays providing protection. The overall differential is a harmonic restrained relay that covers the complete transformer zone, including high-side and low-side lead bus. The internal transformer differential is also a harmonic restrained relay that covers just the transformer. The lead buses are each protected separately with high-impedance-type differential relays. Thus, the transformer and lead bus are protected by two primary schemes from two vendors.

The protection system has been designed considering dual station batteries with System A and B relays located on separate panels. Controls for each relay system, such as breaker open/close, are provided using programmable pushbuttons located on the relays. Target information for each relay system is provided using programmable LEDs (light-emitting diodes) located on the relays. Alarm, SCADA (supervisory control and data acquisition), sequence of events, oscillography, and disturbance recording data are also provided by the relays.

Both relay systems provide phase time-overcurrent (TOC) elements in the relays. The use of transformer overcurrent relays is to provide both transformer protection and backup protection for low-side faults. Overcurrent protection is connected to both the transformer high and low sides.

All transformers are equipped with fault pressure relay (FPR) protection. The FPR provides added sensitivity to detect turn-to-turn faults and low-grade internal faults in the transformer. The FPR typically trips for faults below the differential element sensitivity.

B. General Considerations

The new EHV substations will be arranged in a double-bus/double-breaker configuration for maximum operational flexibility and reliability.

Each transformer installation will be designed for an ultimate configuration of seven individual single-phase transformers with switching to enable fast and easy substitution of the spare transformer into any phase of either transformer bank. See Fig. 1.

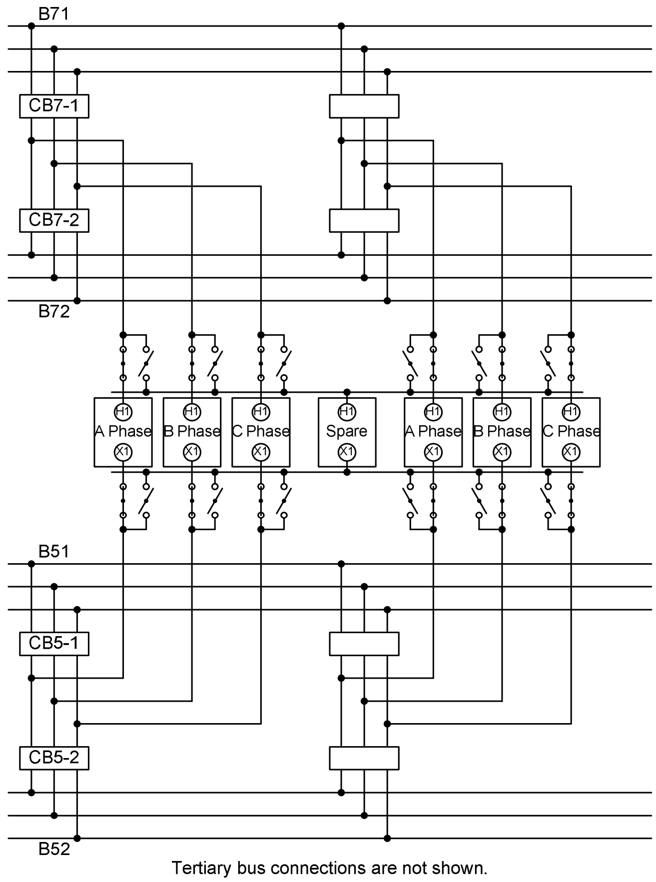

Fig. 1. Two Three-Phase Banks With Shared Spare

Protection systems must be capable of reconfiguring automatically when the spare transformer is substituted into any phase of either transformer bank. When the spare is inserted into the opposite bank, the protection systems on the other bank must be able to ignore the current in the spare transformer CT circuits. It is not necessary for the protection systems to ignore current in one of the fixed transformers in a bank when it is out of service and the spare is substituted into its place.

The following are additional considerations for the new protection system design:

- Clear faults in adjacent zones and on the lead buswork external to the transformers with high-speed to limit through-fault damage to transformer windings and bracing. This can significantly improve the lifespan of the transformers.
- High-speed clearing of internal transformer faults reduces the energy released inside the tank. Fast fault clearing can prevent catastrophic tank rupture, damage to the core steel, and limit collateral damage to adjacent equipment in the substation. Limiting damage, when an internal fault does occur, allows much faster and more economical repair.
- Determine with high accuracy if the fault is internal or external to one of the transformers to allow fast restoration of the transformer for external faults.
- Apply protection elements with high sensitivity for partial winding faults to trip and limit damage before it evolves into a high-level fault.

C. Single-Line Diagram

Fig. 2 shows a single-line diagram that will be used throughout the rest of this section to discuss the various protection systems being considered. This diagram uses the "list box method" described in IEEE Standard C37.2 [3] to describe the protective elements being considered and in which multifunction device they will be implemented. Table I provides a legend for the diagram.

TABLE I
TRANSFORMER SINGLE-LINE DIAGRAM LEGEND

Element	Suffix	Description
24		Volts per hertz, overexcitation
49T		Transformer thermal overload monitoring and protection
RTD		RTD (resistance temperature device) input module
	A	Ambient temperature
	TO	Top-oil temperature
	HS	Hottest spot temperature
50BF-*b*		Breaker failure
	b	5-1 = 500 kV CB1, 5-2 = 500 kV CB2, 7-1 = 765 kV CB1, 7-2 = 765 kV CB2
51P-*v*		Phase time-overcurrent, backup protection
	v	5 = 500 kV terminals, 7 = 765 kV terminals
51G		Tertiary 1I0 overcurrent, backup protection
63 w/50P		Fault pressure with 50P supervision
59P-B7		765 kV terminal phase-to-neutral overvoltage
59N-B3		34 kV 3V0 ground fault protection
87P-*z*		Phase differential protection
	z	O = overall, B7T1 = 765 kV T1 lead bus, B5T1 = 500 kV T1 lead bus, B3T1 = 34 kV tertiary bus, T1 = transformer zone
87Q-O		Negative-sequence differential protection, overall zone

An A or B in the multifunction relay device code indicates which battery system the relay will be on. The CT and voltage transformer (VT) circuits are also color-coded blue and red to indicate if they are associated with System A or B, respectively. A number on the CT or VT circuit indicates how many signals are represented by the single-line representation. This number is used to help the user understand how the spare transformer CTs are wired into the system. Switching for substituting the spare transformer is not shown.

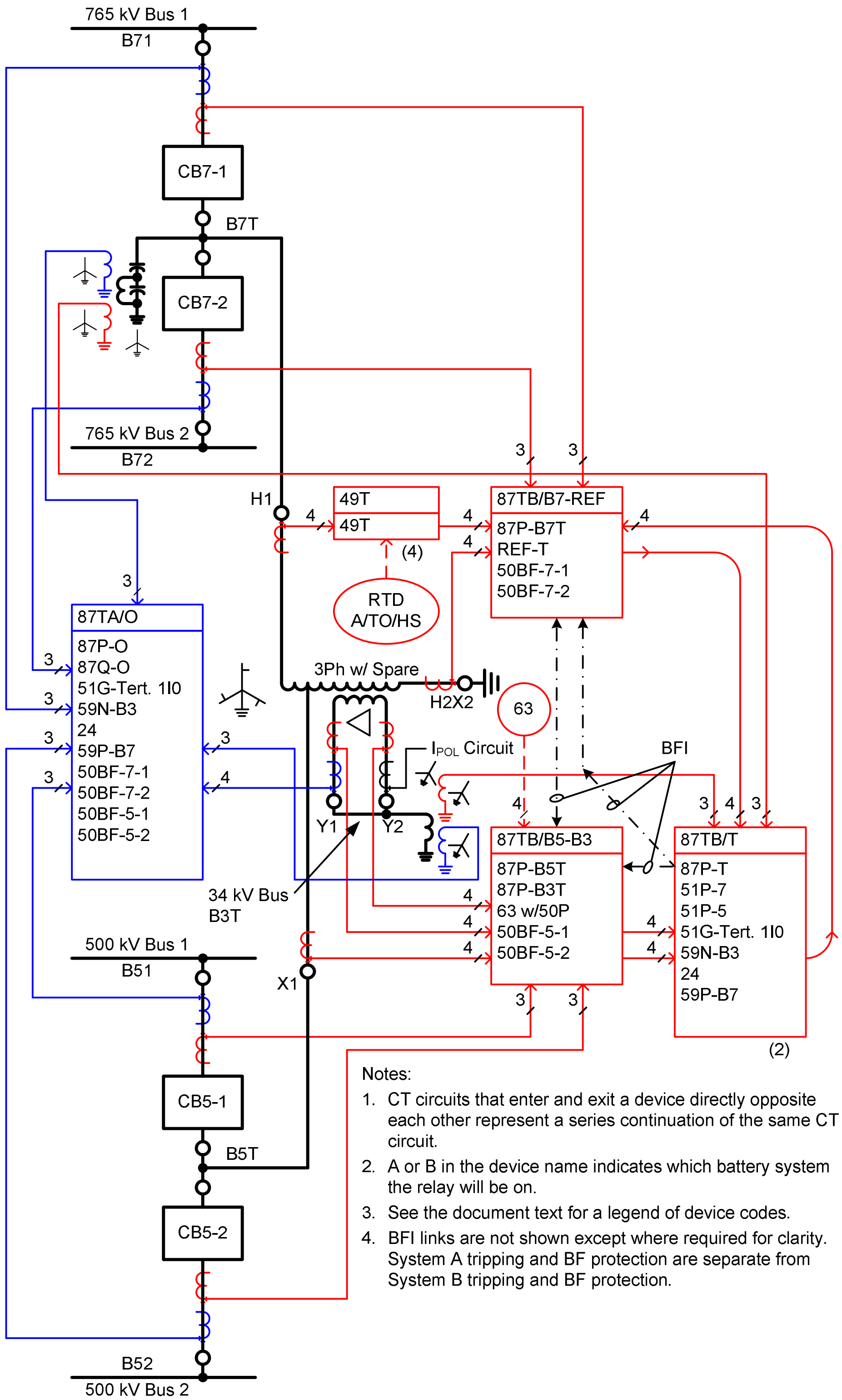

Fig. 2. Transformer Protection Single-Line Diagram

D. Phase Differential Protection

1) Overall Differential (87P-O)

The overall differential protection zone is applied because it requires no switching of CT signals when the transformer bank is configured for spare substitution. An overall differential is also a good solution because of its relative simplicity. In Fig. 2, this scheme is shown implemented in System A Device 87TA/O. The scheme requires standard transformer differential features, including:

- Percentage restraint for steady state and transient mismatch
- Zero-sequence compensation because the transformer is a ground source
- Harmonic restraint/blocking functions for inrush and overexcitation conditions

There are two main deficiencies in the overall differential protection:

1. Lack of indication of whether a fault is located on the 765 kV lead bus, 500 kV lead bus, 34 kV tertiary bus, or inside one of the transformer tanks.
2. The ultimate sensitivity of the phase differential zone is reduced because the CT ratios at the boundary of the zone must be selected to accommodate the bus rating, which is considerably higher than the transformer rating.

To alleviate these limitations, separate lead bus, tertiary bus, and transformer phase differential zones are proposed. This is consistent with AEP past practices as well.

2) Lead Bus Differential (87P-B7T and 87P-B5T)

The 765 kV lead bus is bounded by the two breakers of the double-breaker/double-bus bay and the transformer H1 bushing CTs. The requirement to accommodate spare transformer substitution into any phase of the bank makes it necessary for the bus differential relay to be capable of switching the CTs from the four transformers into and out of the proper zones, depending upon the configuration of the bank. The 500 kV lead bus has the same requirement.

A modern, low-impedance bus differential relay with advanced zone selection logic can provide this functionality. These relays will provide positive indication of the location of the fault on the lead bus. In Fig. 2, this scheme is shown implemented in System B Devices 87TB/B7-REF and 87TB/B5-B3.

3) Transformer Differential, Alternative 1 (87P-T)

The transformer differential zone is bounded by the H1 and X1 bushing CTs on the transformer tanks. This scheme requires a relay with standard transformer differential features. In Fig. 2, this scheme is shown implemented in System B Device 87TB/T. The transformer bank includes a tertiary winding that will be configured in delta so that the transformer becomes a zero-sequence source. This tertiary bus will include extensive external buswork and switching devices. Because the tertiary bus will not be loaded, it is not necessary to exclude the tertiary bus from the transformer differential zone. However, a separate tertiary bus differential zone is proposed. This protection is discussed later in the paper.

Alternative 1 has the advantage of using relatively conventional transformer differential protection concepts and uses only one relay to accommodate spare substitution. It has the disadvantage of being unable to provide positive indication of the faulted tank.

The differential relay applied for this protection must be capable of switching the CTs from the four single-phase transformers into and out of the proper zones, depending upon the configuration of the bank. While this requirement is easily accommodated by modern, low-impedance bus differential relays for the bus lead zones, it is more difficult for the transformer zone. The transformer zone requires zero-sequence compensation. Zero-sequence compensation is accomplished by delta compensation, which requires that the phase currents be grouped as three-phase sets.

A modern, transformer differential relay that has at least four sets of three-phase restraint inputs, "around the clock" phase shift compensation, and the ability to switch compensation settings using settings groups is required. In the following discussion, the four sets of three-phase inputs are called S, T, U, and W to illustrate how spare substitution can be accommodated. The H1 and X1 bushing CTs from the A-, B-, and C-phase transformer tanks are wired to the S and U inputs, respectively. The H1 and X1 bushing CTs from the spare transformer tank are wired to the A-phase T and W inputs, respectively. The B- and C-phase T and W inputs will not be used.

Zero-sequence compensation will be accomplished in this application by using IA-IB, IB-IC, and IC-IA delta compensation. Table II shows the development of I_{OP} and I_{RES} in each phase differential element. For simplicity, the magnitude compensation factors are ignored in the equations below. Also, in Table II, each variable that represents a current value is a complex number (phasor) quantity, except those whose definition includes the absolute value operator.

TABLE II
DIFFERENTIAL CURRENT EQUATIONS, SYSTEM NORMAL

765 kV Compensated Currents (S Input)	**500 kV Compensated Currents (U Input)**
$I'_{SA} = I_{SA} - I_{SB} = I_{H1A} - I_{H1B}$	$I'_{UA} = I_{UA} - I_{UB} = I_{X1A} - I_{X1B}$
$I'_{SB} = I_{SB} - I_{SC} = I_{H1B} - I_{H1C}$	$I'_{UB} = I_{UB} - I_{UC} = I_{X1B} - I_{X1C}$
$I'_{SC} = I_{SC} - I_{SA} = I_{H1C} - I_{H1A}$	$I'_{UC} = I_{UC} - I_{UA} = I_{X1C} - I_{X1A}$
765 kV Spare Compensated Currents (T Input)	**500 kV Spare Compensated Currents (W Input)**
I'_{TA} = **OFF** = NA – I_{H1S}	I'_{WA} = **OFF** = NA – I_{X1S}
I'_{TB} = **OFF** = I_{H1S} – NA	I'_{WB} = **OFF** = I_{X1S} – NA
I'_{TC} = **OFF** = NA – NA	I'_{WC} = **OFF** = NA – NA
Operate Currents (Relay)	**Restraint Currents (Relay)**
$I_{OPA} = \lvert I'_{SA} + I'_{UA}\rvert$	$I_{RESA} = \lvert I'_{SA}\rvert + \lvert I'_{UA}\rvert$
$I_{OPB} = \lvert I'_{SB} + I'_{UB}\rvert$	$I_{RESB} = \lvert I'_{SB}\rvert + \lvert I'_{UB}\rvert$
$I_{OPC} = \lvert I'_{SC} + I'_{UC}\rvert$	$I_{RESC} = \lvert I'_{SC}\rvert + \lvert I'_{UC}\rvert$
Operate Currents (CT Circuits)	**Restraint Currents (CT Circuits)**
$I_{OPA} = \lvert I_{H1A} - I_{H1B} + I_{X1A} - I_{X1B}\rvert$	$I_{RESA} = \lvert I_{H1A} - I_{H1B}\rvert + \lvert I_{X1A} - I_{X1B}\rvert$
$I_{OPB} = \lvert I_{H1B} - I_{H1C} + I_{X1B} - I_{X1C}\rvert$	$I_{RESB} = \lvert I_{H1B} - I_{H1C}\rvert + \lvert I_{X1B} - I_{X1C}\rvert$
$I_{OPC} = \lvert I_{H1C} - I_{H1A} + I_{X1C} - I_{X1A}\rvert$	$I_{RESC} = \lvert I_{H1C} - I_{H1A}\rvert + \lvert I_{X1C} - I_{X1A}\rvert$

In Table II, we take the CT secondary currents (I_{H1A}, I_{X1A}, etc.) and show how they are converted to zero-sequence compensated currents (I'_{SA}, I'_{TA}, etc.) inside the relay. We then show how I_{OP} and I_{RES} are developed from the compensated currents. Finally, we relate these back to the CT secondary currents.

When the spare is inserted into the bank, its H1 and X1 bushing CT currents must be inserted into the above equations in the proper positions. Fig. 3 and Table III shows the resulting equations for each differential element when the spare is inserted into A-phase. In Table III, the current circuits highlighted in bold have zero current in them. In the final definition of I_{OP} and I_{RES} based upon CT circuits, the terms that are zero have been removed.

TABLE III
DIFFERENTIAL CURRENT EQUATIONS, SPARE SUBSTITUTED FOR A-PHASE

765 kV Compensated Currents (S Input)	**500 kV Compensated Currents (U Input)**
$I'_{SA} = \mathbf{I_{SA}} - I_{SB} = \mathbf{I_{H1A}} - I_{H1B}$	$I'_{UA} = \mathbf{I_{UA}} - I_{UB} = \mathbf{I_{X1A}} - I_{X1B}$
$I'_{SB} = I_{SB} - I_{SC} = I_{H1B} - I_{H1C}$	$I'_{UB} = I_{UB} - I_{UC} = I_{X1B} - I_{X1C}$
$I'_{SC} = I_{SC} - \mathbf{I_{SA}} = I_{H1C} - \mathbf{I_{H1A}}$	$I'_{UC} = I_{UC} - \mathbf{I_{UA}} = I_{X1C} - \mathbf{I_{X1A}}$
765 kV Spare Compensated Currents (T Input)	**500 kV Spare Compensated Currents (W Input)**
$I'_{TA} = I_{TA} - \mathbf{I_{TB}} = I_{H1S} - NA$	$I'_{WA} = I_{WA} - \mathbf{I_{WB}} = I_{X1S} - NA$
$I'_{TB} = \mathbf{I_{TB}} - \mathbf{I_{TC}} = NA - NA$	$I'_{WB} = \mathbf{I_{WB}} - \mathbf{I_{WC}} = NA - NA$
$I'_{TC} = \mathbf{I_{TC}} - I_{TA} = NA - I_{H1S}$	$I'_{WC} = \mathbf{I_{WC}} - I_{WA} = NA - I_{X1S}$
Operate Currents (Relay)	**Restraint Currents (Relay)**
$I_{OPA} = I'_{SA} + I'_{UA} + I'_{TA} + I'_{WA}$	$I_{RESA} = \lvert I'_{SA}\rvert + \lvert I'_{UA}\rvert + \lvert I'_{TA}\rvert + \lvert I'_{WA}\rvert$
$I_{OPB} = I'_{SB} + I'_{UB} + I'_{TB} + I'_{WB}$	$I_{RESB} = \lvert I'_{SB}\rvert + \lvert I'_{UB}\rvert + \lvert I'_{TB}\rvert + \lvert I'_{WB}\rvert$
$I_{OPA} = I'_{SC} + I'_{UC} + I'_{TC} + I'_{WC}$	$I_{RESA} = \lvert I'_{SA}\rvert + \lvert I'_{UC}\rvert + \lvert I'_{TC}\rvert + \lvert I'_{WC}\rvert$
Operate Currents (CT Circuits)	**Restraint Currents (CT Circuits)**
$I_{OPA} = I_{H1S} - I_{H1B} + I_{X1S} - I_{X1B}$	$I_{RESA} = \lvert I_{H1S}\rvert + \lvert I_{H1B}\rvert + \lvert I_{X1S}\rvert + \lvert I_{X1B}\rvert$
$I_{OPB} = I_{H1B} - I_{H1C} + I_{X1B} - I_{X1C}$	$I_{RESB} = \lvert I_{H1B} - I_{H1C}\rvert + \lvert I_{X1B} - I_{X1C}\rvert$
$I_{OPC} = I_{H1C} - I_{H1S} + I_{X1C} - I_{X1S}$	$I_{RESC} = \lvert I_{H1C}\rvert + \lvert I_{H1S}\rvert + \lvert I_{X1C}\rvert + \lvert I_{X1S}\rvert$

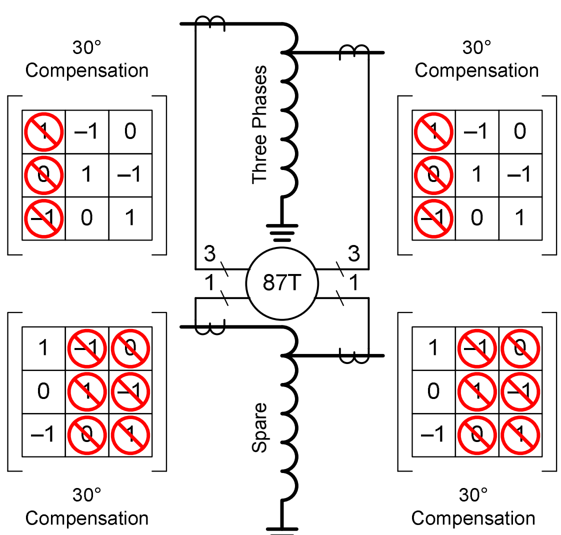

Fig. 3. Spare Substituted for A-Phase

Comparison of the I_{OP} definitions between Table II and Table III shows that the spare transformer CTs in Table III are properly inserted in place of the A-phase transformer CTs, relative to their positions in Table II. So, we can conclude that I_{OP} will always correctly sum to zero for current flow through the reconfigured bank.

Comparison of the I_{RES} definitions shows that the restraint quantities will be slightly different for A-phase and C-phase because the absolute value is taken before the phase currents are combined instead of after. Table IV shows the effect of this difference for the four possible fault types. Examination of Table IV shows that some elements are overrestrained by a factor of 1.15 ($2/\sqrt{3}$) for three-phase or double-line-to-ground faults. Having 15 percent extra restraint is not terribly significant. However, further examination of Table IV shows that at least one element responding to the fault is not over-restrained, so this method of substitution will result in no reduction of sensitivity for internal faults and will actually result in greater security for external faults.

TABLE IV
RESTRAINT ERROR, SPARE SUBSTITUTED FOR A-PHASE,
IN PER UNIT OF NORMAL

Fault Type	**A-Phase Element**	**B-Phase Element**	**C-Phase Element**
ABC Fault	$I_{RESA} = 1.15$	$I_{RESB} = 1.0$	$I_{RESA} = 1.15$
ABG Fault	$I_{RESA} = 1.15$	$I_{RESB} = 1.0$	$I_{RESC} = 1.0$
AB Fault	$I_{RESA} = 1.0$	$I_{RESB} = 1.0$	$I_{RESC} = 1.0$
AG Fault	$I_{RESA} = 1.0$	$I_{RESB} = NA$	$I_{RESC} = 1.0$

When the spare is substituted for B-phase, the relay inputs wired to the spare transformer CTs need to be set with compensation settings that compensate for a phase shift of 120° + 30° = 150°. When the spare is substituted for C-phase, relay inputs wired to the spare transformer CTs need to be set with compensation settings that compensate for a phase shift of 240° + 30° = 270°. In the above equations, the "+ 30°" term is required because all inputs have a 30-degree shift to provide zero-sequence compensation.

This scheme can provide superior sensitivity relative to the overall differential protection because the CT ratios at the boundary of the zone can be selected to accommodate the transformer rating instead of the bus rating. There are two main deficiencies in transformer differential Alternative 1:

1. The scheme is open to the 34 kV tertiary bus, so it cannot provide discrimination for faults on that bus versus faults inside the transformer tanks.
2. Because the scheme must include zero-sequence compensation, it cannot provide identification of the faulted transformer tank.

To alleviate these limitations, a second alternative is being considered for phase differential protection.

4) Transformer Differential, Alternative 2 (87P-T)

Alternative 2 is bounded by the H1, X1, and Y1 bushing CTs on the transformer tanks. In Fig. 2, this scheme is shown implemented in System B Device 87TB/T. This scheme requires a relay with standard transformer differential features, such as harmonic restraint. This alternative has the advantage that it excludes the tertiary bus from the transformer zone, and it provides positive indication of the faulted tank. It has the disadvantage that it uses an unconventional transformer differential protection configuration and requires a separate relay to be applied to the spare transformer. Notice that Fig. 2 shows that System B Device 87TB/T requires two relays.

This scheme uses the concept of balancing ampere-turns on the core of each transformer by measuring the current in each winding segment of the autotransformer and the tertiary winding. Because the current in the tertiary winding is included in the differential, zero-sequence compensation is inherent in the scheme.

This scheme is not used more widely because it requires directly measuring the current in each winding—including delta-connected windings—and is not recommended for three-legged, core transformers. This application lends itself to this approach because we have single-phase transformers with CTs located in the required locations and we want separate lead and tertiary bus and internal transformer zones.

Fig. 4 shows how the ampere-turns balancing differential protection works. There are three distinct windings in the autotransformer:

- Series winding
- Common winding
- Tertiary winding

The series winding and tertiary winding currents are directly measured by the H1 bushing CT and the Y1 bushing CT, respectively. The common winding current can be measured in two ways. It is directly measured by the H2X2 bushing CT, as shown in Fig. 4a. Or it can be measured by subtracting the X1 bushing CT current from the H1 bushing CT current, as shown in Fig. 4b. Notice that the polarity of the H2X2 bushing CT and the X1 bushing CT is reversed.

Using the H2X2 bushing CT instead of the X1 bushing CT has pros and cons.

The pros include:

- It is a simpler CT connection.
- It improves sensitivity for winding-to-ground faults near the neutral of the winding. See the "Transformer Restricted Earth Fault (REF) Protection" subsection of this paper for more discussion on protecting for this type of fault.

Con: It reduces sensitivity if the transformer should fault when energized from the 500 kV terminal with the 765 kV terminal open.

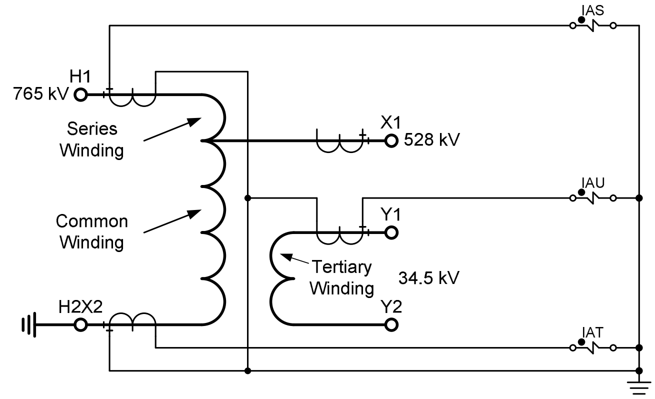

Fig. 4a. Ampere-Turns Balancing Differential, Alternative 1

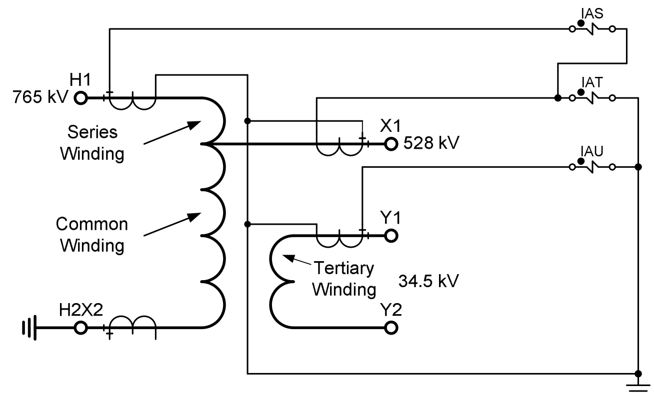

Fig. 4b. Ampere-Turns Balancing Differential, Alternative 2

The CT circuits are each connected to separate three-phase inputs on the relay. Fig. 4 uses S, T, and U to identify the inputs for illustrative purposes. Because zero-sequence compensation is not required, wye compensation can be used so that there is no delta connection of phase currents in each of the three differential elements.

The tap factors for each input are calculated based on the actual voltage rating of each winding. The following example illustrates how the relay is set:

Transformer:

$MVA_{1\Theta} = 750$

$V_{PP}kV_{H1} = 765$ $V_{PN}kV_{H1} = 441.7$

$V_{PP}kV_{X1} = 528$ $V_{PN}kV_{X1} = 304.8$

$V_{PP}kV_{Y1} = 34.5$

$CTR_{H1} = 400T$

$CTR_{Y1} = 1200T$

$CTR_{H2X2} = 200T$

Calculate the MVA rating of the series winding to use as the per-unit base:

$$I_{H1} = \frac{MVA_{1\Theta} \bullet 1000}{V_{PN}kV_{H1}} = \frac{750\ MVA \bullet 1000}{441.7\ kV} = 1698\ A \quad (1)$$

$$MVA_{1\Theta}SERIES = (V_{PN}kV_{H1} - V_{PN}kV_{X1}) \bullet I_{H1} \quad (2a)$$

$$MVA_{1\Theta}SERIES = (441.7\ kV - 304.8\ kV) \bullet 1698\ A = 232.4\ MVA \quad (2b)$$

The tap factor calculations for each input to the relay are shown in the following equations:

$$TAP\_S_{H1} = \frac{MVA_{1\Theta} \bullet 1000}{VkV_{SERIES} \bullet CTR_{H1}} \quad (3a)$$

$$TAP\_S_{H1} = \frac{232.4\ MVA \bullet 1000}{(441.7\ kV - 304.8\ kV) \bullet 400} = 4.25 \quad (3b)$$

$$TAP\_T_{Y1} = \frac{MVA_{1\Theta} \bullet 1000}{VkV_{TERTIARY} \bullet CTR_{Y1}} \quad (4a)$$

$$TAP\_T_{Y1} = \frac{232.4\ MVA \bullet 1000}{34.5\ kV \bullet 1200} = 5.61 \quad (4b)$$

$$TAP\_U_{H2X2} = \frac{MVA_{1\Theta} \bullet 1000}{VkV_{COMMON} \bullet CTR_{H2X2}} \quad (5a)$$

$$TAP\_U_{H2X2} = \frac{232.4\ MVA \bullet 1000}{304.8\ kV \bullet 200} = 3.81 \quad (5b)$$

To obtain positive faulted tank identification to improve restoration times, AEP is considering choosing Alternative 2—even though it requires one additional relay that is applied as a single-phase relay. This scheme has a further advantage that it does not require reconfiguring the CTs included in each zone during substitution of the spare transformer.

E. Partial Winding Fault Protection

Partial winding faults can be difficult for the phase differential element to detect. Partial winding faults include turn-to-turn faults and turn-to-ground faults. A winding-to-ground fault is especially difficult for the phase differential elements when it is near the neutral point of a wye-connected winding. When a few turns are shorted on a transformer winding, the transformer acts as an autotransformer and steps down the current in the shorted turns by the ratio of shorted turns/full-winding turns so that the current seen at the terminals of the transformer is small.

The current in a turn-to-turn or turn-to-ground fault can be very high and dissipate a great deal of energy at the location of the fault. Providing protective elements that are sensitive to these types of faults can allow these faults to be detected and tripped before they have to evolve to involve more turns so that they can be detected by the phase differential elements.

1) Fault Pressure Protection (63 w/50P)

The fault pressure relay is the classic device for detecting turn-to-turn faults inside the tank. This protective function detects the rapid pressure rise caused by the energy in the arc across the shorted turns. However, this element can misoperate because of winding movement during high-current external faults. For this reason, AEP has for many years applied current supervision to improve the security of this element.

In Fig. 2, this scheme is shown implemented in System B Device 87TB/B5-B3. Because each transformer tank is isolated from the others, this protective function will provide positive indication of the faulted tank.

2) Transformer Restricted Earth Fault (REF) Protection

REF protection is recommended to detect faults near the neutral terminal of the autotransformer winding. For these faults, we have the advantage that the current in the fault loop can be measured directly by the neutral bushing CT. The ground current can be quite high. There are two main schemes used for REF protection.

- Current polarized directional ground element
- High-impedance bus differential element

The bank includes four separate transformers with four separate H2X2 bushing CTs that must be summed to get the neutral current. This presents problems for the traditional schemes, but it also presents an opportunity to get positive faulted tank identification. So a modified scheme is being considered.

The directional schemes available in modern transformer relays use the current in the power transformer neutral as the polarizing reference and the current in the residual at the boundary of the zone as the operating signal. See Fig. 5a. A simple directional comparator can determine if the ground fault is internal or external to the tank. These schemes can be set with high sensitivity because they count on the fact that the neutral of the power transformer is made up inside the tank and the ground current can be measured using a single CT. There is no chance of false zero-sequence current in the polarizing signal because of CT performance issues for an external fault not involving ground. However, because with single-phase transformers, current at the neutral is measured with a residual connection of the three neutral bushing CTs, absolute security of this scheme cannot be guaranteed.

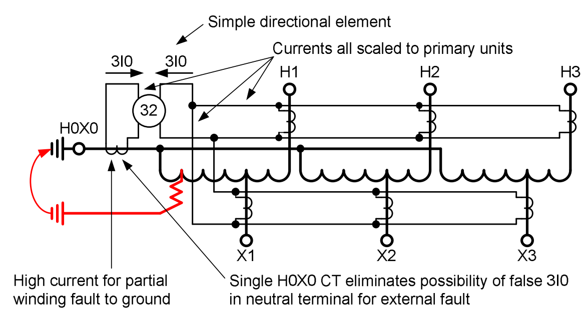

Fig. 5a. Traditional Current Polarized Directional REF Scheme

An additional problem with the directional element scheme is that it is necessary to switch the current signals from the spare into the measurements of zero-sequence current in the zone. This is not easily accomplished in the REF schemes available in the microprocessor-based relays being considered. And finally, this REF scheme does not identify the faulted tank.

The high-impedance bus differential scheme is connected so that the zero-sequence current sums to zero between the neutral CT and the residual of the H- and X-phase CTs as shown in Fig. 5b. This scheme has inherently high security for false residual currents and, therefore, would be suitable for this application, where a residual connection of three CTs is included at the neutral of the power transformer. If a microprocessor-based, three-phase, high-impedance relay were to be applied, this scheme could be modified to use the three separate elements—one for each tank as shown in Fig. 5c. This would provide faulted tank identification [4]. However, this scheme requires dedicated equal ratio CTs, which will increase wiring. And it has no way of accommodating the spare transformer without using a separate relay or switching CT secondary circuits.

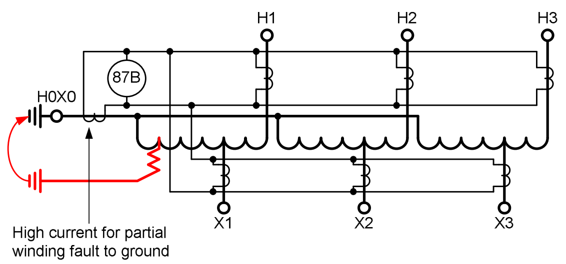

Fig. 5b. Traditional High-Impedance REF Scheme

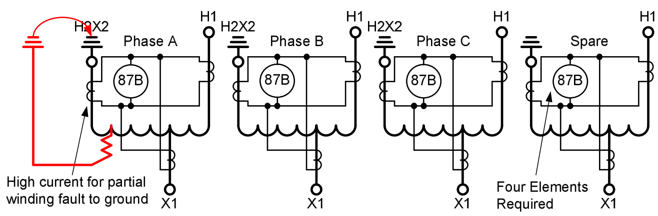

Fig. 5c. Modified High-Impedance REF Scheme to Provide Phase Selection

The modified scheme being considered uses the three unused zones in Device 87TB/B7-REF to create an REF zone for each individual tank as shown in Fig. 5d. The three zones can be switched inside the relay based upon bank configuration to cover the spare. Because the currents at each terminal of the winding are summed as in a bus differential zone, no magnetic effects, such as inrush, typical of a transformer application, will affect these differential elements. For this reason, a bus differential relay without harmonic restraint is suitable.

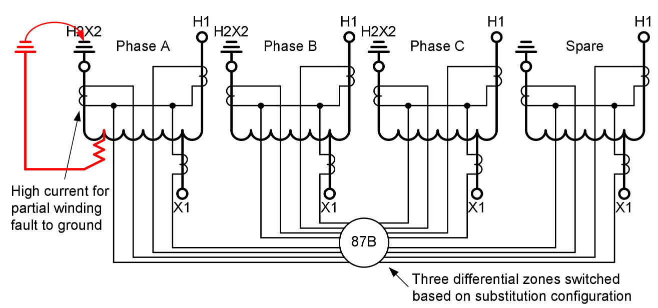

Fig. 5d. Low-Impedance REF Scheme to Provide Phase Selection and Spare Substitution

3) Negative-Sequence Differential Protection (87Q)

AEP has applied negative-sequence differential protection with good success on phase-shifting transformers [5]. This scheme can provide superior sensitivity to all faults in the zone, including turn-to-turn faults, because there is very little negative-sequence through current during normal load flow to restrain the relay. The 87Q element available in one of the modern transformer relays being considered uses an external fault detector to disable the very sensitive element during external faults where false negative-sequence current could occur because of CT performance issues.

This scheme is included in System A Device 87TA/O to complement the fact that System B has both REF and 63 protection functions to cover partial winding faults. The 87Q function will also mitigate the reduced sensitivity of the 87P elements because the overall differential CT ratios are governed by the bus rating and not the transformer rating. This scheme cannot provide positive identification of the faulted bus or tank location.

87Q protection cannot be implemented in System B Device 87TB/T because, when the spare is inserted, the relay will read large, steady-state, negative-sequence current flow in the zone. This is because the phase current will be missing from the normal transformer inputs to the relay and present in the spare transformer inputs to the relay. Referring to Fig. 3, during substitution, each current input to the relay will measure 0.33 per unit $3I2$ current flow during balanced conditions. The negative-sequence currents will sum to zero, but they will be overly restrained, resulting in no added sensitivity.

F. Tertiary Bus Protection

The transformer bank includes a tertiary winding that is to be configured in delta so that the transformer becomes a zero-sequence source to the transmission system. This tertiary bus will include extensive external buswork and switching devices. Tertiary faults have historically been especially damaging to transformers, so high-speed, sensitive detection of faults in this zone is recommended.

The tertiary bus will be operated ungrounded with surge arrestors on the bus to limit overvoltage relative to ground caused by capacitive coupling. Operating the tertiary bus ungrounded reduces the exposure of the tertiary windings and buswork to high-current faults. With this configuration, the only high-current faults that can occur will be external to the transformer tanks in the buswork for a multiphase fault. Multiphase faults are not possible on the tertiary winding inside the tank.

1) Phase Differential Protection (87P-B3T)

Tertiary bus, high-speed phase differential protection is being considered to trip the transformer zone high speed for a multiphase fault in the tertiary buswork. The tertiary bus will be inside the zone of protection of the 87P-O and 87P-T (Alternative 1) zones, so these elements will provide protection but not be as fast and sensitive. Also, they will not be able to provide positive identification of the fault location. The tertiary bus protection will provide positive indication that the fault is external to the transformer tanks.

In Fig. 2, this scheme is shown implemented in System B Device 87TB/B5-B3 and uses the three unused zones to create a differential zone for all buswork external to the transformer tanks. The three zones can be switched inside the relay based upon bank configuration to cover the spare.

The traditional approach of connecting CTs on one set of tertiary bushings in delta to filter out the zero-sequence current circulating in the delta winding and using a 50P element was rejected. While possible, it would be much more difficult to substitute the tertiary current from the spare transformer correctly into the delta calculation for each of the bank configurations.

2) Ground Fault Overvoltage Protection (59N-B3)

Wye-connected VTs will be installed so that 3V0 can be measured by either a broken delta connection or 3V0 calculated inside the relays for 59N protection. Measuring all three phases and calculating 3V0 will allow determination of which phase has the ground fault for better diagnostics and quicker correction of the problem. This advantage must be balanced against the advantage of the neutral stabilizing effect of a broken delta VT connection, with a stabilizing resistor connected across the corner of the broken delta.

In Fig. 2, this scheme is shown implemented in both System A Device 87TA/O and System B Device 87TB/T. This function may be used to alarm and not to trip.

G. Faulted Equipment and Phase Selection

As stated under the general requirements, highly accurate indication of the fault location is important. Table V summarizes the zone protection elements and whether they can provide positive indication of the fault location.

TABLE V
TRANSFORMER FAULT LOCATION INDICATION

System	Element	Description	Fault Indication
A	87P-O	Overall phase differential	N
A	87Q-O	Overall negative-sequence differential	N
B	87P-B7T	765 kV lead bus phase differential	Y
B	87P-B5T	500 kV lead bus phase differential	Y
B	87P-T (Alt. 1)	Transformer phase differential	N
B	87P- T (Alt. 2)	Transformer phase differential	Y
B	REF-T	Transformer winding restricted earth fault	Y
B	63	Fault pressure	Y
B	87P-B3T	34 kV tertiary bus phase differential	Y
B	59N-B3	34 kV tertiary bus ground fault	N

H. Overcurrent and Backup Protection

Overcurrent protection is primarily used for detection of faults beyond the transformer zone. It protects the transformer from damage caused by uncleared faults in adjacent zones. The overcurrent elements are coordinated to trip the transformer before the through-fault withstand limit is exceeded on the transformer windings. There are no problems with providing phase overcurrent protection during spare substitution. However, protection elements that use 3I0 from inside the delta tertiary require consideration to accommodate spare substitution.

1) Tertiary Ground Overcurrent Protection (51G-Tert. 1I0)

The tertiary winding will only see large current during external series (SPO) and shunt ground (SLG and DLG) faults. For this reason, it is typically not rated the same as the phase windings. The phase winding overcurrent and thermal overload elements cannot provide proper protection for these windings. Thus, dedicated tertiary overcurrent protection that responds to the current circulating in the delta is used.

Fig. 2 shows this protection implemented in both System A Device 87TA/O and System B Device 87TB/T to provide full redundancy between System A and System B for this function.

Because the tertiary is unloaded, it is not necessary to sum the three-phase currents to filter out the positive- and negative-sequence current flow. The current in each Y1 bushing can be measured, and a separate overcurrent element calibrated to respond to 1I0, can provide this protection. If a shunt reactor or some other load is ever connected to the tertiary bus, it will become necessary to calculate 3I0 from all three phases. One of the modern transformer relays being considered includes custom programmable math functions that can allow the user to calculate 3I0 from the three out of four transformers that are active in a given configuration.

2) Current Polarizing Circuit for Ground Directional Protection

AEP often uses dual polarized ground directional relaying, which requires an I_{POL} signal from the ground source transformers in the substation. One CT from all four or seven transformer Y1 or Y2 bushings can be connected in parallel to provide the polarizing current. It is not necessary to switch the CTs based upon bank configuration to provide a correct polarizing signal because all currents, if present, will be in the correct direction.

I. Verification of Zone Configuration

The transformer zone has a high degree of complexity compared to most substation zones. Each zone can be configured into four valid configurations of 24 switches—including system normal and the spare transformer substituted into any phase. This raises the possibility of incorrect primary switching configurations that could result in any number of issues, such as an open-phase condition, open circuit in the delta tertiary bus (loss of ground source), or phase-to-phase short circuit. In addition, the protection systems must also be configured into the correct matching configuration. Because most of the protection zones are protected by differential, mismatch between the protection system configuration and the primary system configuration will tend to result in overtripping as opposed to failure to trip.

When we consider the second transformer bank, there are seven valid configurations for the two zones. Of even more concern, there will be interdependency between the two transformer banks, which raises the risk of taking both out of service at the same time and opening the transmission path for an incorrect primary switching configuration or a mismatch of the protection system configuration with the primary system configuration. This risk must be mitigated, or the reliability goals for the power system could be compromised.

For these reasons, the protection and control system design must include logic to aid in preventing human error and identifying status indication faults that may allow an incorrect configuration of either the primary power system or the protection system. The following are some ideas being considered to address this concern.

The status of all switches will be brought into System A and System B separately. The single status signal in each system for each switch will be shared by all devices in each system. This eliminates the possibility that a single contact in the wrong state can cause one of the devices to be in the wrong configuration. The following techniques can ensure that the configuration information is valid:

- The status of the configuration between the systems can automatically be compared for congruence using integration technology and programmable logic [6].
- Because the likely time for a status error to occur is during a switching operation, the control system should indicate an operate fail if the status signal does not change state as expected.
- All relays should indicate their configuration, “System Normal,” “Spare Substituted for A,” etc.
- Both 89a and 89b contacts should be used to indicate status. If they do not indicate a valid state, a status incongruent alarm should be indicated.
- Automated switching sequence logic should be programmed into the control relays to reduce the possibility of human error in switching sequences.
- The operator should verify configuration prior to re-energizing a bank after reconfiguration.

J. Transformer Monitoring Functions

Modern relays can measure and record two key health parameters for power transformers: thermal and through fault. Information provided by these two functions, when taken together, can provide a good indication of the health of the transformers, as shown in Fig. 6 [7]. However, these important transformer life statistics cannot be accurately accumulated during spare substitution in a three-phase relay. For this reason, Fig. 2 shows four separate transformer monitoring devices labeled 49T.

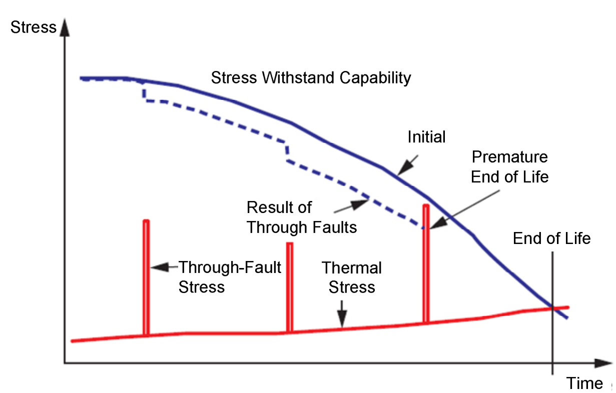

Fig. 6. Combined Effect of Thermal Stress and Through Fault on End of Life

Using four separate devices has the further benefit of eliminating the need to wire RTD signals from the four transformer tanks to a single centrally located device.

K. Redundancy Considerations

The scheme illustrated in Fig. 2 provides functional redundancy. The protection and control system on dc System A and B is not identical. However, wherever possible, complementary functions are carefully implemented in each system to provide comparable sensitivity and performance. Another alternative that is being considered is to add an additional transformer differential relay to System B and configure it as an overall differential with 87P-O and 87Q-O elements only. This system would then be simply duplicated so that System A and System B are identical.

This alternative has the advantage of simplicity of application, in addition to complete redundancy of all features, including positive identification of the faulted equipment. Considering the cost and importance of these facilities to the bulk power system and the relative inexpensiveness of modern, multifunction protection and control equipment, this alternative has merit.

IV. Reactor Protection

A. Present Protection Practices

Single-phase, 765 kV reactors currently rely on protection schemes developed when some of the original 765 kV AEP system was developed. The reactor bank is protected with a CEY53A impedance relay, a CFD22A current differential relay, and an FPR. The reactors are wye-connected with a solidly connected neutral, except for lines with single-pole tripping and reclosing.

When applying single-pole tripping, a fourth reactor is installed. The fourth reactor is protected with a BDD15 and an IAC51A relay. A spare 100 MVAR reactor is also installed at selected stations and those with single-pole tripping to expedite failed reactor replacement. The 100 MVAR spare has a CEY53A, PJC11, and IAC60 relay for protection during test energization. A 20 MVAR, switchable spare is also installed at single-phase tripping terminals and has a BDD15 and IAC51 relay for test purposes.

The CEY53A single-phase, zone-impedance relay was specially designed by GE for shunt reactor protection. The relay has the ability to change impedance reach (i.e., to pull back reach with frequency ringdown). As the frequency decreases, the mho unit maximum torque angle becomes less lagging, and, also, the diameter of the mho circle decreases. The reactor impedance decreases with frequency ringdown and saturation effects, and a standard impedance relay reach may likely extend its reach during fault conditions. Therefore, the relay design characteristics were an important consideration for reactor protection.

The CFD22A is a three-unit, induction cup, current differential relay. This type of construction results in a fast operate device even at currents only slightly in excess of pickup values. The relay functions for both phase-to-phase and phase-to-ground faults. The relay operates when the difference current exceeds a set amount.

All reactors are equipped with FPR protection. The FPR provides added sensitivity to detect turn-to-turn faults and low-grade internal faults in the reactor. The FPR would typically trip for faults below the CFD or BDD differential relay sensitivity.

B. General Considerations

The line reactor banks are made up of three-phase reactors with spare and one neutral reactor with spare, and each includes switching to enable fast and easy substitution of the spare reactors into any phase or neutral of the reactor bank. The bus reactor banks are made up of three-phase reactors with spare. These installations will also include switching to enable fast and easy substitution of the spare reactor into any phase. The present plan does not include multiple reactor banks on any line terminal or bus, so it is not necessary to share a spare between multiple reactor banks.

Protection systems must be capable of reconfiguring automatically when a spare reactor is substituted. It is not necessary for the protection systems to ignore current in any of the fixed reactors or in the spare reactor CT circuits because the spare reactor is not shared with another bank, as was the case with the transformer zone.

The reactor zone has similar issues to the transformer zone regarding high-speed clearing to limit damage and positive indication of faulted equipment to speed restoration of a failed bank by switching in a spare. The following are additional considerations:

- EHV shunt reactors are constructed as oil filled with a gapped core. The gapped core can create magnetic effects similar to a transformer, including inrush current when the core saturates upon initial energization and autotransformer effect, causing high current in turn-to-turn faults.
- The high X/R ratio of a reactor causes any dc offset in the switching current after energization or clearing an external fault to last a long time. This long dc transient can drive the gapped core into saturation, resulting in inrush currents from 1 per unit to as high as 5.5 per unit that can last for several seconds.
- The reactor switching current is a small value relative to the maximum available fault current. However, the high X/R ratio means that CT saturation cannot be completely avoided during reactor switching. Protection systems must have a high degree of immunity to CT saturation.
- When the line is de-energized with the reactors in service, subharmonic resonance currents and voltages will be measured by the protective relays. The protective element algorithms must have good immunity to subharmonic signals.
- The neutral buswork and neutral reactors will only see significant voltage during SPO conditions and faults involving ground. It will be difficult to sense faults in these areas of the reactor zone using electrical protection. Mechanical detection elements such as fault pressure, low oil, etc. are important [8].
- The differential zones are not sensitive to turn-to-turn faults. Turn-to-turn faults result in a reduction in impedance and a circulating fault current that adds to the phase current through transformer action [9]. In the four-legged reactor application, the neutral unbalance current caused by turn-to-turn faults will be limited by the neutral reactor impedance.

C. Sensitivity Considerations

The phase reactors will be rated for 225 A primary at 765 kV. The line circuit breakers will be rated 4,000 A with 3000:5 CTs with a thermal factor of two. It is undesirable to require CTs for the reactor breaker with ratings that differ from the standard configuration because of spare equipment concerns. The reactors are equipped with two 2000:5 A CTs on both the high-voltage and neutral terminals. Achieving adequate sensitivity with 400T and 600T CTs was considered at great length.

The phase zones will include the external lead buswork (including the switching and buswork to substitute the spare reactor) between the breaker and the high-voltage terminals of the reactors. This area can include both phase and ground faults. Faults in this area will be of high magnitude, and sensitivity is not a concern. Inside the reactor tanks, winding-to-ground faults can occur. For an inside-the-tank, winding-to-ground fault, the current can be as low as the reactor rated current.

The phase differential element can be responsive to the minimum fault because the current will divide between flowing through the fault and through the neutral bushing, resulting in operating current in the differential element. It is desirable to be able to achieve sensitivity around 0.25 per unit of reactor rating.

The neutral bus will have current flowing in it equal to the reactor rated current under normal operation. The voltage on this bus during normal system operation will be very low, resulting in little potential to cause insulation breakdown. Only during ground faults and SPO conditions will the neutral bus experience significant voltage relative to ground. This bus will be insulated to 138 kV class standards. However, sensitive differential protection can detect ground faults based upon the current flow through this zone.

The neutral reactor will only have current flowing in it during ground faults and SPO conditions. High sensitivity is required to detect faults in this zone.

Sensitivity must be balanced with security. Sensitivity is often achieved by using differential protection. When set with high sensitivity, differential protection can be susceptible to misoperation on false differential current caused by CT saturation. Another method to achieve high sensitivity is to use zero- and negative-sequence current elements with very sensitive settings. These protection elements can also be susceptible to misoperation for false unbalance current caused by CT saturation. For this reason, the design must be optimized to reduce the possibility of CT saturation.

To balance sensitivity with security, a combination of approaches is being considered.

1. Relay selection and arrangement.
   a. Consider using high-impedance differential relays where possible because of their inherent immunity from CT saturation, coupled with inherent high sensitivity.
   b. Separate the lead bus zone, which does not require high sensitivity, from the reactor tank and neutral bus zones that do.
2. Minimize the possibility of CT saturation.
   a. Arrange the CT circuits to reduce the possibility of false differential current. This approach is detailed in the "Installation Considerations" subsection of this paper.
   b. Do not use less than the full winding of the CTs if possible.
3. Look for ways to enhance the sensitivity of relays connected to 400T and 600T CTs.
   a. Option 1: Wire each CT current into the relays twice. For example, the high-voltage terminal CTs would be wired to two sets of CT inputs and the neutral terminal CTs would be wired to two sets of CT inputs on the relay. A 3000:5 CT will then have an effective ratio of 3000:10. This provides a two-to-one improvement in sensitivity limits.
   b. Option 2: Specify 1 A, nominal-rated relays so that the effective ratio is 400:1 or 600:1. This provides a five-to-one improvement in sensitivity limits. This second option is preferred.

D. Single-Line Diagram

Fig. 7 shows two single-line diagrams that will be used throughout the rest of this section to discuss the various protection systems being considered. It illustrates the protection for a four-legged reactor bank. The three-legged reactor bank would be similar. Table VI provides a legend for the diagram.

An A or B in the multifunction relay device code indicates which battery system the relay will be on. The CT and VT circuits are also color-coded blue and red to indicate if they are associated with System A or B, respectively. A number on the CT or VT circuit indicates how many signals are represented by the single-line representation. This is used to help the user understand how the spare reactor CTs are wired into the system. Switching for substituting the spare reactors is not shown.

TABLE VI
REACTOR SINGLE-LINE DIAGRAM LEGEND

Element	Suffix	Description
49		Reactor mechanical thermal overload monitoring and protection
63		Fault pressure protection
51N		Neutral inverse-time overcurrent protection
59N		Zero-sequence overvoltage for ground overcurrent supervision protection
67N		Ground directional element (terminal) with neutral overcurrent tripping element
71G		Gas accumulator protection (Bucholtz)
71Q		Low oil level
87P-z		Phase differential protection
	z	O = Overall, B7RX = 765 kV RX lead bus
87RX-z		Reactor differential protection
	z	A = A-phase RX, B = B-phase RX, C = C-phase RX, S = spare-phase RX, N/NS = neutral and spare neutral RX.
87-BNRX		Neutral differential protection
REF		Restricted earth fault protection

E. Differential Protection

1) Low-Impedance Versus High-Impedance Differential

Low-impedance bus differential relays are recommended where spare substitution requires switching of CTs to reconfigure the zones. In Fig. 7, System A Device 87RXA/O and System B Device 87RXB/B7RX must have this capability because CTs at one boundary of the zone are in the four phase reactors.

In Fig. 7a, System B Device 87RXB/RX that covers the reactor tanks and neutral bus is also a low-impedance bus differential relay. Because the currents at each terminal of the reactor are summed as in a bus differential zone, no magnetic effects, such as inrush, will affect these differential elements, so a bus differential relay without harmonic restraint is suitable. This relay provides six total differential elements to be used as follows:

1. A-phase reactor
2. B-phase reactor
3. C-phase reactor
4. Spare phase reactor
5. Neutral bus
6. Neutral reactor/spare neutral reactor

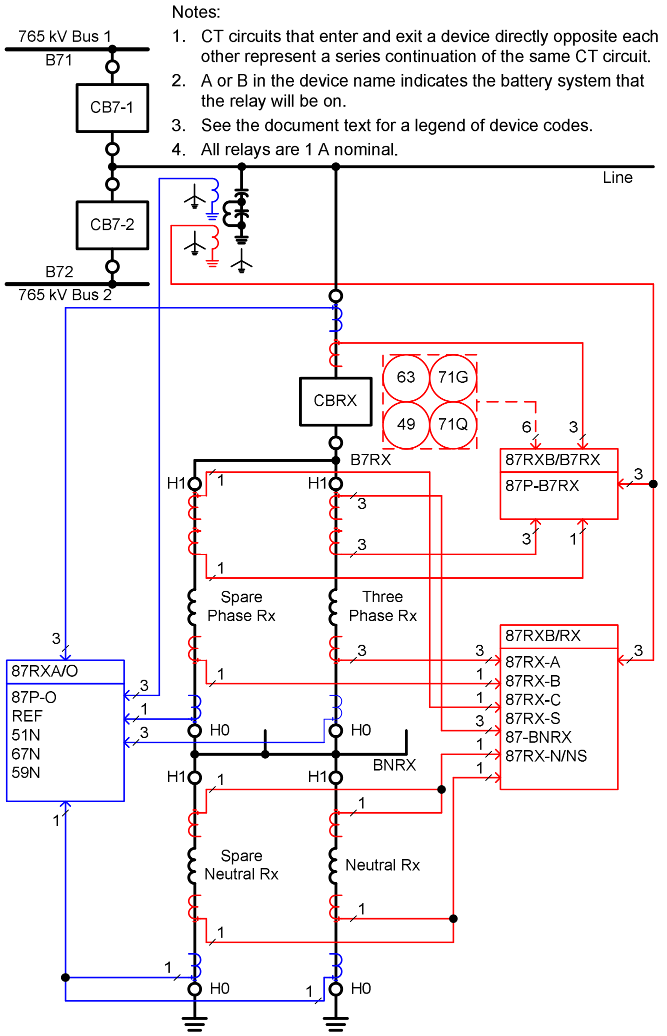

Fig. 7a. Reactor Protection Single-Line Diagram With Low-Impedance Differential Relays

Because the neutral reactor and the spare neutral reactor can never be in service at the same time, it is permissible that these share a common protection zone.

Per the above, zone switching capability is not required for these zones. However, the ability of a modern, low-impedance bus differential relay to share CT circuits at zone boundaries makes this option desirable.

High-impedance relays are desirable for the zones where high sensitivity is desired (i.e., the inside of the reactor tank zones and the neutral bus zone). High-impedance relays are nearly completely immune from operation on false differential current. They provide high sensitivity because a small differential current can create a large voltage across the 2,000-ohm relay burden resistor. The lead burden between the summing junction and the relay is also not significant for application of these relays. This makes them the best technology available for inside the reactor tank and neutral bus fault detection.

The drawback of high-impedance differential relays is that they require dedicated CTs, and they are not recommended for applications where CT switching is required. Fig. 7b shows that the reactors would require three bushing CTs on the H0 bushing of the phase reactors. This is not the standard configuration of the existing reactors that AEP has in service or as spares, so this alternative will not likely be pursued.

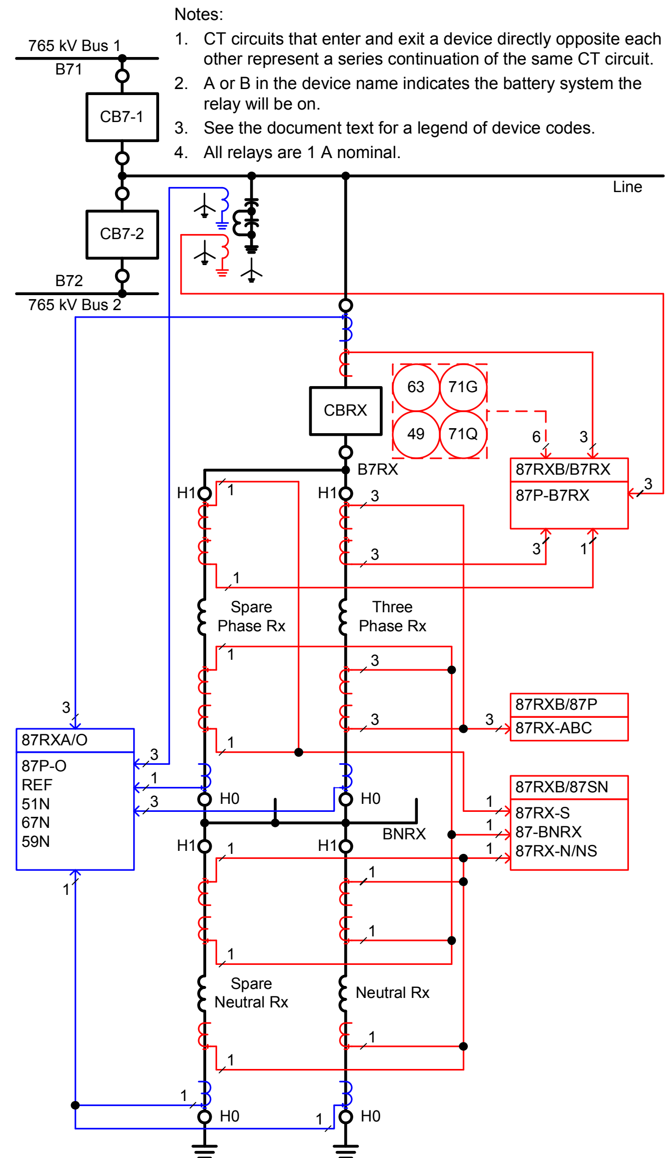

Fig. 7b. Reactor Protection Single-Line Diagram With High-Impedance Differential Relays

In Fig. 7b, two three-phase, high-impedance differential relays (Device 87RXB/87P and 87RXB/87SN) are shown. The six differential elements available in the two relays would be allocated the same as discussed for the low-impedance relay.

2) Overall Differential (87P-O)

In Fig. 7, an overall differential protection zone is shown implemented in System A Device 87RXA/O. This zone is bounded by the breaker CTs and the neutral terminal bushing CTs of the phase reactors. The neutral bus and neutral reactor are not covered by differential protection in System A.

This zone can experience high-current, phase-to-phase and phase-to-ground faults in the reactor lead bus. Inside the reactor tanks, only phase-to-ground faults are likely. System A is proposed to include REF protection for high-sensitivity protection for faults in the neutral bus, neutral reactor, and inside the phase reactor tanks.

The relay being considered for use here is a transformer differential relay that includes the required REF and directional overcurrent functions in addition to differential protection. To obtain a better compromise for security versus sensitivity, we plan to use second-harmonic restraint to better tolerate false differential because of CT saturation.

As discussed in the “Transformer Protection” section of this paper, for a transformer relay, CT circuit zone switching has to be done in three-phase sets. So to accommodate spare substitution, the plan is to use a five-input differential relay. The first CT input will be wired to the three-phase breaker CTs, which do not have to be switched. The remaining four CT inputs will be wired so that the spare CT is inserted into the correct phase for each of the four possible configurations.

These differential elements should be set as sensitively as possible without sacrificing security. Detailed study and simulation are planned to arrive at settings that provide a suitable tradeoff of sensitivity versus security. We also plan to enable harmonic restraint to enhance security to false differential caused by CT saturation. Inrush suppression logic can also be implemented to enhance security [10]. This logic is discussed in a subsequent subsection of this paper.

3) Lead Bus Differential (87P-B7RX)

In Fig. 7, a lead bus differential protection zone is shown implemented in System B Device 87RXB/B7RX. This zone is bounded by the breaker CTs and the high-voltage terminal bushing CTs of the phase reactors. This zone can experience high-current, phase-to-phase and phase-to-ground faults in the reactor lead bus. These differential elements do not need to be set with high sensitivity. These relays will provide positive indication of the location of the fault on the lead bus.

4) Reactor and Neutral Bus Differential (87RX-ABCS, 87-BNRX, and 87RX-N/NS)

In Fig. 7, differential protection for each of the six reactor tanks and the neutral bus zone is shown implemented in System B. This protection could be provided by either low-impedance or high-impedance differential relays, as previously discussed.

It should be noted that these differential elements will not respond to turn-to-turn faults. Mechanical protection elements are included in System B to cover these types of faults.

5) Inrush Suppression Logic

Low-impedance bus differential relays include logic to put them in high-security mode when an external fault is detected. This allows the sensitivity versus security tradeoff to be optimized for bus applications. However, the reactor application is different. The currents that cause CT saturation are of relatively low magnitude with high X/R ratios. Saturation can occur several seconds after the reactor is switched, which may be after the high-security mode timer has expired. It is desirable to set these differential zones with high sensitivity, which will make them susceptible to misoperation on relatively low amounts of CT saturation. For this reason, special inrush suppression logic is proposed to improve the security of these elements.

Fig. 8 shows the proposed logic. The falling edge of the open phase detector logic determines when the reactor is first energized. This asserts a four-second pulse timer. Upon detecting the reactor inrush current, the relay goes into high-security mode (CON1 asserts) in anticipation of the possibility of CT saturation. The output of AND gate PSV01 asserts:

- When the high-security mode is deasserted.
- AND, the reactor has been energized less than four seconds.

The output of AND gate PSV01 blocks the sensitive differential element 87R1. If an internal fault occurs while the output of AND gate PSV01 is asserted, a high-set, unrestrained differential element (PSV02) is enabled to provide protection.

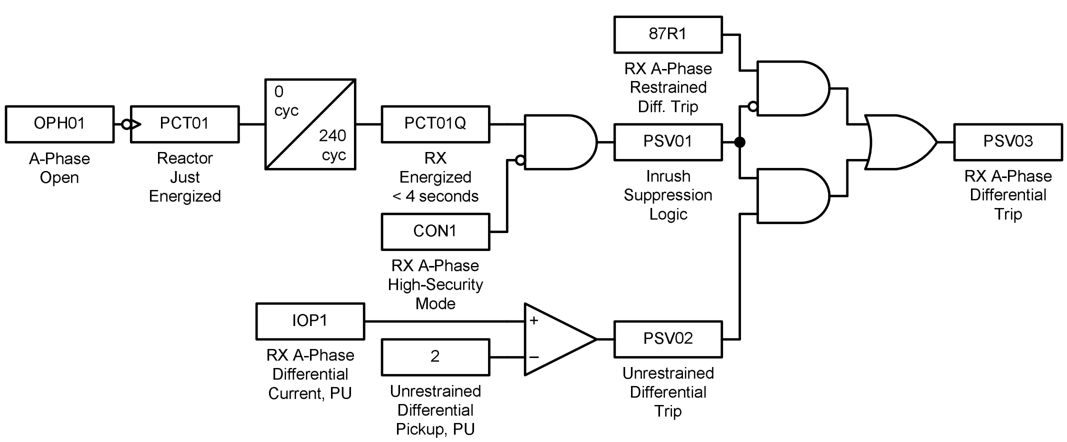

Fig. 8. Inrush Suppression Logic

F. Reactor Restricted Earth Fault Protection

REF protection is recommended for System A to provide protection for ground faults in the neutral bus and neutral reactor and sensitive protection for ground faults inside the reactor tanks. In Fig. 7, this scheme is shown implemented in System A Device 87RXA/O. REF protection uses a current polarized directional element that compares the angle of the 3I0 current at the boundary of the zone with the 3I0 current flowing through the neutral of the reactor bank. It is necessary that the neutral current be from a single CT measuring the ground current so that it is impossible that false neutral current caused by CT saturation can flow. To accomplish this for the three-legged reactor banks, the neutral bus of the reactor bank must be grounded through a single point that passes through a neutral CT of comparable rating to the circuit breaker CTs.

These relays will not provide positive indication of the location of the fault.

G. Turn-to-Turn Fault Protection

Turn-to-turn faults can result in a reduction of the impedance and create circulating current in the shorted turns because of transformer action. This causes the current to become unbalanced. However, unbalanced current can also flow because of zero-sequence unbalances on the power system, making sensitivity to turn-to-turn faults difficult to achieve.

1) Ground Overcurrent Protection (51N and 67N)

Fig. 7 shows a directional ground overcurrent element implemented in System A Device 87RXA/O. This protection will use a zero-sequence voltage polarized directional element to detect zero-sequence current flow into the reactor. Because of the possibility of false residual current caused by CT saturation, the residual current at the boundary of the zone will not be used for tripping. The directional element will torque control an overcurrent element that is responsive to the current in the neutral CT of the reactor [10]. This is the same current used in the REF protection.

This element will be set in the range of 0.05 to 0.10 per unit of reactor rating. To further enhance security, inrush suppression logic similar to that proposed for the differential elements will block this sensitive protection for four seconds after initial energization of the reactor bank. Fig. 7 includes a 59N element. This element may be used to further supervise this sensitive protection during external ground faults. Simulation will determine if this element is actually needed. A 51N element is also included.

This protection will not provide positive indication of the fault location.

2) Mechanical Protection (49, 63, 71G, and 71Q)

It is important to monitor mechanical protection for the reactor banks to supplement electrical protection for turn-to-turn faults. This is especially true for the neutral reactor because it will only see appreciable current and voltage for brief times during a ground fault or SPO condition. Consideration should be given to trip for these conditions instead of alarm. Fig. 7 shows this protection implemented in System B through Device 87RXB/B7RX to complement turn-to-turn electrical fault protection provided by directional ground overcurrent elements in System A.

H. Faulted Equipment and Phase Selection

As stated under the “General Requirements” section of this paper, a highly accurate indication of the fault location is important. Table VII summarizes the zone protection elements and whether they can provide positive indication of the fault location.

TABLE VII
REACTOR FAULT LOCATION INDICATION

System	Element	Description	Fault Indication
A	87P-O	Overall phase differential	N
A	REF	Restricted earth fault	N
A	67N	Directional ground overcurrent	N
B	87RX-B7RX	765 kV lead bus phase differential	Y
B	87RX-ABCS	Phase reactor differential	Y
B	87RX-N/NS	Neutral reactor differential	Y
B	87-BNRX	Neutral bus differential	Y
B	63	Fault pressure	Y
B	71G	Gas accumulator	Y

V. Installation Considerations

EHV substations occupy a very large area. The distance between primary equipment and protection and control equipment is not insignificant. Large distances result in high costs for cabling, concerns about voltage drop in auxiliary power circuits, and burden in sensing circuits. Methods to reduce cabling costs are also being considered in the development of the next generation of standards.

A. CT Circuits for Transformer Zones

Current-sensing circuits are typically arranged in a three-phase and neutral four-wire circuit. The reason for this is to reduce the number of conductors required. It also reduces the burden that the CTs have to overcome because under most conditions, the currents in the phase conductors sum to a smaller value or zero, which reduces or eliminates the burden of the return conductor.

In the past, a three-phase EHV transformer bank made up of three single-phase transformers typically required the installation of a CT junction box, where all of the CT circuits are brought together to make up the three-phase current circuits before they were run into the control building. When a spare transformer was included, the CT junction box also provided a point to reconfigure the current circuits when the spare was substituted. In this application, the CT circuits will not be physically reconfigured. They will be permanently wired into the relays.

So, to minimize the burden by making three-phase sets that balance, it would be necessary to connect each three-phase CT circuit with four phases and a neutral. However, this is undesirable because the substations are planned to accommodate seven transformers. Thus the CT circuits would have to be wired in a seven-phase, neutral, eight-wire configuration. This is also undesirable because the two banks would then have circuits in common, which could lead to possible loss of both banks because of an error or problem.

The proposed CT circuit configuration takes advantage of the attributes of modern, microprocessor-based protection devices. That is:

- Each phase current input is isolated from the others, with two isolated terminals.
- Residual and differential operate quantities are calculated and no longer need to be derived from physical connections of CT circuits.
- The current inputs are extremely low burden, allowing all relays on System A to share a CT circuit and all relays on System B to share a separate CT circuit.

These attributes have allowed elimination of the CT junction box and reduced the number of CT circuits that have to be run to the control building. The current circuits can be arranged so that the currents sum to zero from each single-phase transformer bank, which eliminates the need for making up three-phase sets in the substation yard.

B. CT Circuits for Reactor Zones

For reactor zones, the high X/R ratio makes it impossible to eliminate the possibility of CT saturation. Careful arrangement of the CT circuits can minimize the possibility of this occurring. To accomplish this, the CT circuits can be arranged in such a way that each CT only has to push the one-way lead burden, and the burden of the return lead acts to stabilize and reduce the false differential current caused by CT saturation. How this is accomplished is detailed in the following sections.

1) Overall and Lead Bus Differential Zones

The lead bus and the overall differential zones are bounded by the three-phase breaker CTs and CTs in the four-phase reactors. AEP plans to make these into eight-wire circuits using the circuit breaker (CB) control cabinet as the CT junction point. The eight-wire circuit includes seven-phase leads and one return lead. Fig. 9 and Fig. 10 shows how this configuration results in current in the return lead only during internal faults or external faults with CT saturation.

An external ABG fault is used to illustrate the concept. Fig. 9 shows that including both boundaries of the differential zone in the eight-wire CT circuit results in the return lead current always being zero for through-current flow. Fig. 10 shows that a false differential current caused by CT saturation is forced to flow through the return lead. The return lead resistance helps stabilize the differential circuit. This configuration is effective for spare substitution cases as well. In the figures, load current is ignored for simplicity.

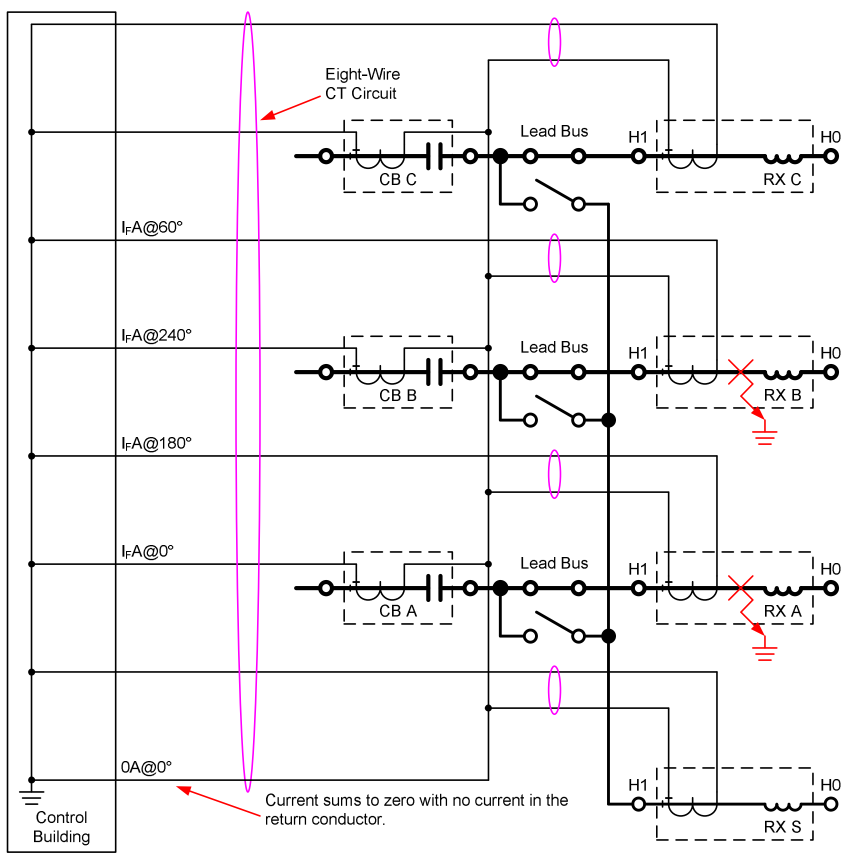

Fig. 9. Eight-Wire CT Circuit, External ABG Fault Without CT Saturation

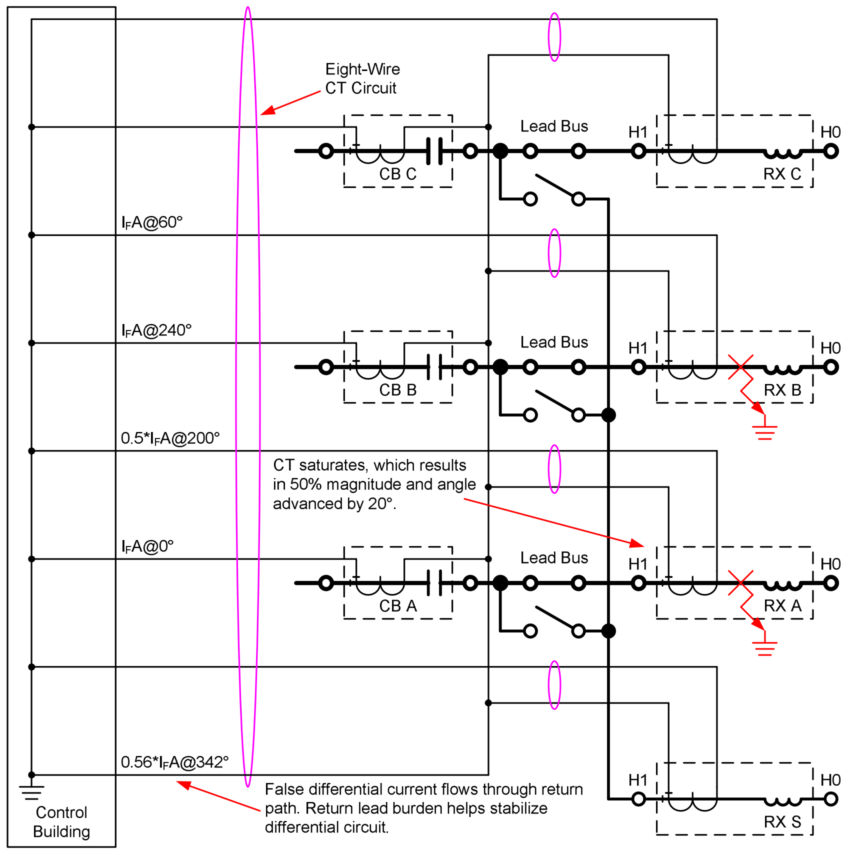

Fig. 10. Eight-Wire CT Circuit, External ABG Fault With CT Saturation

2) Reactor Differential Zones, Low-Impedance Differential Relay

The boundaries of the reactor differential zones are the high-voltage terminal and neutral terminal CTs. These CT circuits are planned to be configured as three-wire circuits. The CTs are connected differentially so that current flows in the return lead only during internal faults or during CT saturation. The return lead resistance helps stabilize the differential circuit.

3) Reactor Differential Zones, High-Impedance Differential Relay

With high-impedance relays, if the differential zones are summed at the location of the equipment, lead burden to the relays becomes irrelevant because the lead burden is in series with the high impedance of the relay. To facilitate consolidating the CT circuits and changing out a failed reactor, a CT junction box would be required if high-impedance relaying is used.

VI. PROTECTION SYSTEM MAINTENANCE REQUIREMENTS

Owners of electrical facilities that are part of the bulk power system must test and maintain their protection systems [1]. It is necessary for them to demonstrate that they have a maintenance program with a justifiable basis for maintenance intervals and verification that they follow their program.

The NERC System Protection and Control Subcommittee created a technical reference that describes maximum maintenance intervals based upon the level of self-monitoring built into the protection system. They define a protection system with “full monitoring” as not requiring a periodic verification interval because all possible failures can be detected and corrected to minimize exposure to undesired operation [2].

Using integration technologies, it is possible to build many continuous monitoring features into the protection and control system [11]. One goal of the next generation design effort is to attempt to achieve full monitoring to improve the performance of the bulk power system, while minimizing maintenance and testing costs.

This requirement is a compelling reason to apply identical System A and System B protection systems in the next generation of standards. It becomes easy to verify the complete protection measurement functions in the relay and their associated instrument transformer circuits when every relay and its measurements are duplicated between the systems. Using synchrophasor technology, including synchrophasor-capable relays and synchrophasor processors, every critical measurement from both systems is easily compared on a continuous basis without more complicated verification routines.

VII. Conclusions

The value of this paper for the industry is the explanation of how any three-out-of-four or six-out-of-seven single-phase tanks can be utilized for reactor or transformer installations, while affording rapid restoration after a failure. The ability to have a readily available spare cut into any phase of up to two three-phase banks in switching time provides planners with a new concept. Following the opportunity covered in detail in this paper can allow planners to consider higher MVA three-phase banks using single-phase equipment with less outage impact for all voltages where size and weight may be the MVA limit determining factors. It is important to understand that this approach is not just applicable to EHV installations.

This paper has provided sufficient guidance on how to use the versatility available in microprocessor-based relays to build three-phase banks using single-phase tanks with a spare that allows fast restoration of important bulk power system installations. The authors encourage protection engineers and system planning engineers to discuss these concepts and use them to improve the fault tolerance and availability of these expensive investments.

VIII. References

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IX. Biographies

Henry (Hank) Miller has a BSEE and a BEE from The Ohio State University and a BA in Philosophy from The Pontifical College Josephinum. He is a registered professional engineer in the state of Ohio and holds a patent for a substation steel design. Hank has over 27 years of utility experience in station and line protection and control. Hank is currently working for American Electric Power (AEP) as a staff engineer in the protection & control asset engineering group with responsibilities for developing protection and control standards, application guides, and supporting the relay setting project work. He shares responsibility for ensuring that new devices to the AEP system are protected and controlled properly with John Burger. Hank is a member of the IEEE.

John Burger has a BSEE from Case Institute of Technology and a MSEE from Fairleigh Dickinson University. He is a registered professional engineer in the states of Ohio and New Jersey. John has over 35 years experience in station and line relay protection and control. He has worked for American Electric Power (AEP), primarily in the protection and control group, for the last 27 years. John is currently serving as a staff engineer in the protection & control asset engineering (P&C) group with responsibilities for developing protection and control standards, application guides, and supporting the relay setting project work. John has responsibility for workload management of the P&C group, including the contractor support functions. He shares responsibility for ensuring that new devices to the AEP system are protected and controlled properly with Hank Miller. John has also worked as a protection and control specialist with the AEP energy services team and with the People’s Republic of China on the Ertan 500 kV Transmission Project. John is a Senior Member of the IEEE, past chairman of the Columbus Chapter of the PES, a member of the IEEE Power System Relay Main Committee, Substation and Communications Subcommittees, and Chairman of Working Group H6. He is also currently serving as Chairman of the UCA International Users Group, providing technical support for IEC 61850.

Michael J. Thompson received his B.S., magna cum laude, from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a Principal Engineer in the Engineering Services Division of SEL. He is a senior member of the IEEE, main committee member of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael has published numerous technical papers and holds a number of patents associated with power system protection and control.

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