Analysis of Multiple Misoperations following an External Fault

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Abstract— **Analyzing transmission relay misoperations for external distribution faults can challenge protection engineers. This paper examines how a recent close-in fault on a 33 kV feeder at a Con Edison transmission substation resulted in the loss of two power transformers, two 138 kV transmission lines, and an area (distribution) substation nearby. Fault records from digital fault recorders, protective relays, and power quality meters were utilized to determine the sequence of events and root causes. These modern waveform and event data sources, along with assessment of the physical features of the installation, gave critical insight into the nature and root causes of the misoperations.**

Through a thorough review of the relay oscillography files, it was found that the System 1 and System 2 line current differential relays for both the 138 kV lines misoperated during this external fault on the 33 kV feeder. CTs on the 138 kV bushings of the two power transformers form part of the line differential zone for these lines. Fault analysis and modeling of CT performance suggested that saturation of the 138 kV bushing CTs was the root cause of the misoperation of the line differential relays.

In order to avoid future misoperations, as part of the Corrective Action Plan for this event, the current differential protection of 138 kV lines (eight relays) was revised to remove the CT contribution from the transformers. A second part of the Corrective Action Plan included a change of settings to the line current differential relays on both lines.

This technical paper will include an overview of the Con Edison transmission and distribution systems, the design basis of this specific protection scheme, and the event analysis, including all testing and results as well as a description of the Corrective Action Plan and lessons learned from the event. Lessons learned include avoiding external paralleling of CTs, assessing CT accuracy and performance during the design phase, establishing line differential setting sensitivity criteria, and managing legacy relay system designs.

I. INTRODUCTION

Consolidated Edison Company of New York, Inc. (Con Edison) is one of the largest investor-owned utilities in the world. Founded in 1823 as the New York Gas Light Company, Con Edison provides electric, gas, and steam services to 9 million people over 604 square miles of New York City (NYC) and Westchester County in New York. Con Edison owns approximately 94,000 miles of underground cable and 34,000 miles of overhead conductors [1].

Because of its dense service territory, Con Edison operates one of the most complex electric systems while still providing extremely reliable electric services to customers in NYC.

System disturbances and interruptions can occur at any time. When these events occur, quicky isolating the faulted power system element during a correct relay operation, and quickly realizing and identifying the mis-operated relay protection system during an incorrect relay operation, are crucial parts of the rapid system restoration.

II. OVERVIEW OF CON EDISON'S ELECTRIC SYSTEM

Con Edison operates its distribution system at three different voltage levels: 33kV, 27kV and 13kV. Its distribution substations also known as area substations, operate with multiple transformers in parallel, with each of these transformers supplied by their own dedicated transmission or sub-transmission supply feeders at various voltage levels. The transmission or sub-transmission supply feeders are with few exceptions from the supply substations. A high-level arrangement of an area substation is shown in Fig. 1, with load feeders not shown.
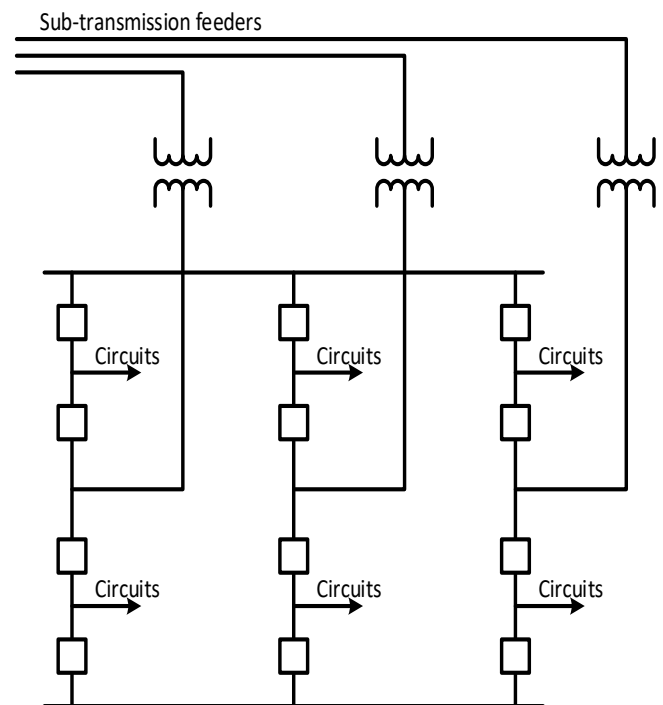

Fig. 1. High level arrangement of an area substation

Most of these area substation transformers do not have a high side interrupting device, so during a fault on the sub-transmission feeder, the feeder's source substation will be cleared by its local breaker(s), and the area substation will be clearing with its low side breaker(s). 50/51 and 51N elements

are mainly used at the source substation to detect sub-transmission feeder faults. On detection, this protection will send direct transfer trip to its downstream area substation to trip. The area substation also has its own 59N and 67 to provide sequential clearing if no communications is available, or as backup protection. In some cases, 87L line differential element is used to protect the sub-transmission feeder.

III. DESIGN BASIS OF THIS PARTICULAR TRANSMISSION AND DISTRIBUTION SYSTEMS

A. Area Distribution Substation 33 kV Feeder Protection

These feeders are each protected by both phase and ground overcurrent relays. The phase relays have both instantaneous elements to operate for higher current feeder faults closer to the substation, and time overcurrent elements to operate for lower current feeder faults remote from the substation. The ground relays have only time overcurrent elements. Single-phase-to-ground fault current levels are limited by neutral-to-ground reactors on the wye-connected secondary windings of the area substation transformers, thereby minimizing the difference in the current level for ground faults on a feeder close to the substation versus far from the substation. The use of both instantaneous and time overcurrent elements for ground faults is therefore of little value. Time overcurrent elements alone are used, affording the opportunity to set them more sensitively without sacrificing security. The event discussed in this paper featured an initial single-phase-to-ground fault that evolved into a phase-to-phase fault, so it's not surprising that the instantaneous phase overcurrent element operated ahead of the ground time overcurrent element.

B. Transmission Bus Section and Sub-transmission Feeder Protection

The two bus sections in the transmission substation that cleared during this event are each shared by 1) transmission tie feeders to a remote transmission substation with dedicated breakers locally, 2) connections to the high side delta-connected windings of transformers at the local area substation where the distribution feeder fault occurred and 3) sub-transmission feeders to a remote area substation without dedicated breakers. This configuration is depicted in Fig. 2.
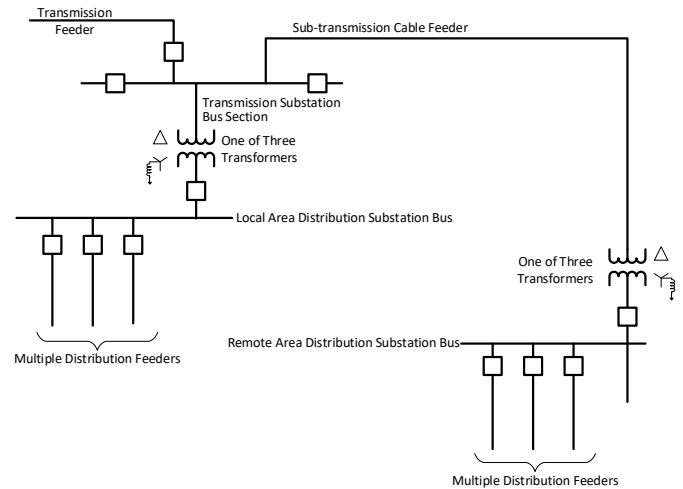

Fig. 2. Facilities sharing a bus section at the transmission substation

The sub-transmission feeders are comparatively long underground cables operated at transmission voltage. Because transmission substation bus sections must be cleared for faults either on the bus sections themselves or anywhere along the sub-transmission feeder cables, the zones of protection covering both the bus sections and the sub-transmission feeder cables are the same. Protection is implemented with line differential relays using breaker CTs on the transmission substation bus sections and transformer CTs at the remote area distribution substation supplied by the sub-transmission cable feeders.

The connections to the high side delta-connected windings of transformers at the local area distribution substation that share the bus sections with the sub-transmission cable feeders comprise tapped loads that naturally upset the balance of the line current differential zones of protection that cover both the transmission bus sections and the sub-transmission cable feeders. In order to reestablish balance in the line current differential zones, CTs on the high side terminals of those local area distribution substation transformers were connected so as to include any transformer through current, load or fault, from the line differential zone current summation. Fig. 3 shows CT circuit connections. Since the transformer bushing CTs have a different turns ratio from the bus and feeder breaker CTs, summation of the current with other line zone contributions requires auxiliary CTs. Because of limited CT inputs on the line differential relays used, the current-summation secondary wiring connections were made up externally to the line current differential relays as depicted in Fig. 3.
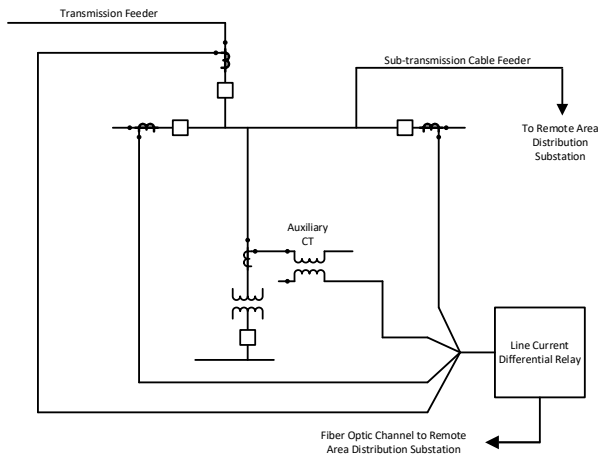
Fig. 3. Externally summed CT connections to line differential relay

In addition, when this protection scheme was installed, the line differential relays used for System 1 and System 2 had to share the one available bushing CT signal from each transformer.

The use of line current differential relaying on sub-transmission cable feeders supplying area distribution substations is not typical. A more common scheme is to use simple phase and ground overcurrent relaying, similar to that used on distribution feeders. That relaying is localized to the transmission substation and clears the transmission bus sections high speed. Back-feed from the remote area distribution substation into a sub-transmission cable feeder fault is cleared either by relaying at the remote area distribution substation, or by transfer tripping from the transmission substation. In the case of the event being reported here, however, the extended length of the sub-transmission cable feeders results in potentially damaging high Ferranti-rise and transient over-voltages during the period of back-feed, thereby requiring that said period be held to a minimum duration. Line current differential relaying on the sub-transmission cable feeders accomplishes that purpose. It does require communication channels between the transmission substation and the remote area distribution substation, but it offers the needed increase in the speed of clearing. Dedicated, dark fiber-optic cables were installed to provide the communication channels.

IV. EVENT ANALYSIS

The question to address during this event is why the line differential relays for 138 kV Feeder A and 138 kV Feeder B operated during a close-in feeder fault on the 33 kV system at the local substation. Both Feeder A and Feeder B serve the same remote substation through transformers that connect to a distribution bus. Feeder E also serves the same remote substation, but is not normally in service, and was not in service during this event.

The first step in this analysis is to retrieve all data from protective relays, fault recorders, and other devices that are available in the local substation and the remote substation. Based on event logs retrieved from relays, both the 85-1 (System 1) and 85-2 (System 2) relays operated at the local substation for both Feeder A and Feeder B, and they operated on their line differential element. The oscillography from the 85-1 relays from both lines shows a form of CT saturation, as in Fig. 4. (Only low resolution filtered oscillography was retrieved from the 85-2 relays and was of no use. Other oscillography was retrieved from a fault recorder located at the local substation, mostly recording data from the 345 kV system, and some power quality monitors located on the 33 kV side of two of the transformers feeding the 33 kV bus.
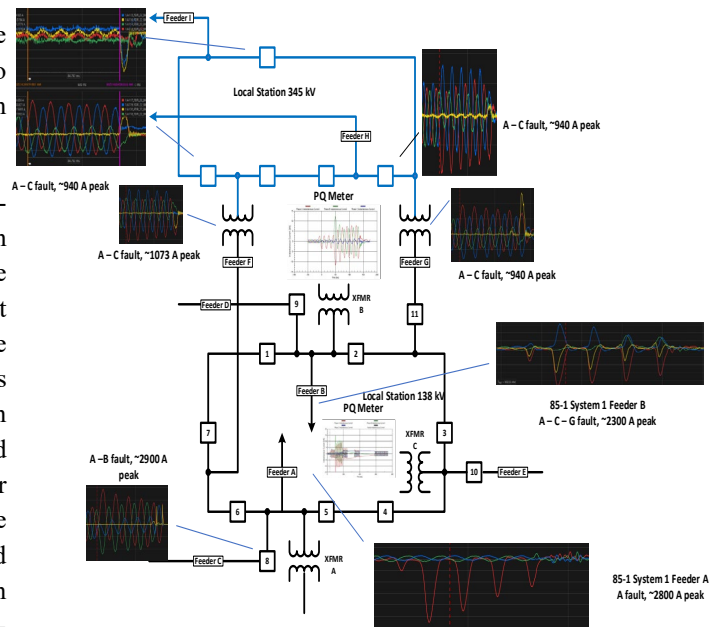

Fig. 4. Oscillography

From these waveforms, it is apparent that the other devices in the local substation captured the fault event, showed similar waveforms to each other, and did not show the saturated waveforms captured by the Feeder A and Feeder B relays. Analysis of the line differential operation then quickly focused on the apparent CT saturation seen by the relays.

Both Feeder A and Feeder B have the circuit arrangements of Fig. 2: a ring bus section that includes a transformer supplying the 33 kV bus, a feeder supplying the remote substation, and a 138 kV line connected through its own single circuit breaker. The circuit arrangement is therefore no longer truly a ring bus but is a bus of its own.

A. Feeder A Relay Operation Analysis

Starting the analysis with Feeder A is simpler, because the local substation fault recorder captured currents on Feeder C

during the event. There are 5 currents associated with this bus, only 4 of which are measured. The Feeder A line currents are the sum of the 4 measured currents, as shown in Fig. 5. During this event, only the Feeder A current (I_5 in Fig. 5, captured by the 85-1 relay) and the Feeder C current (I_2 in Fig. 5, captured by the fault recorder), are known. The peak fault currents on A-Phase are approximately 2,900 A on Feeder C, and 2,800 A on Feeder A.
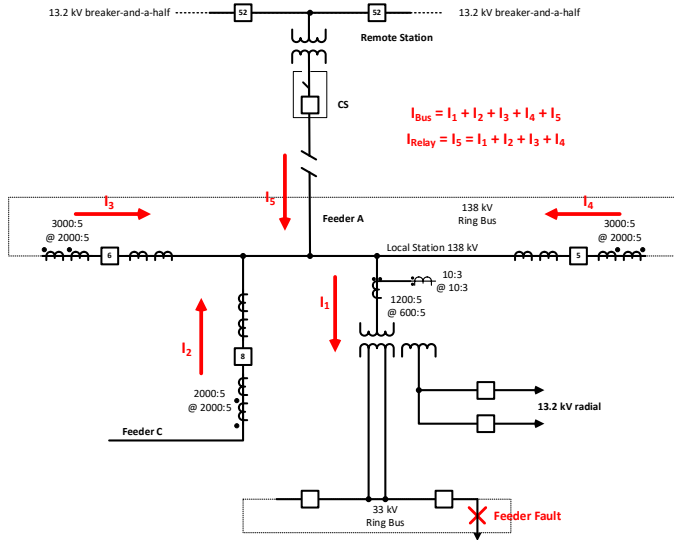

Fig. 5. Currents for Feeder A bus section

Since the relay waveform looks like a form of CT saturation, the obvious first step is to model CT performance during this fault event. A short circuit study performed for this fault event showed that almost all of the current contribution to the fault would come from Feeder C, with almost no contribution from the rest of the bus flowing through Circuit Breakers 5 and 6. The starting point for this analysis is the connected CT circuits for the 85-1 and 85-2 relays of Fig. 6.

B. Circuit Breaker 8 CT modeling

Analysis used the IEEE PSRC CT Saturation Calculator spreadsheet tool [3] to analyze the performance of the Circuit

Breaker 8 CTs, the CTs for the Feeder C line, measuring the I_2 current of Fig. 5.
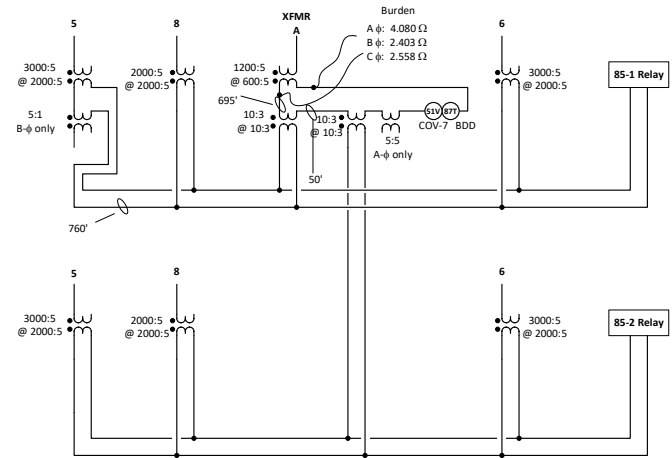

Fig. 6. Feeder A's line relays CT circuits

The CTs are modeled as generic C800 2000:5 CTs. Therefore, generic values for the saturation curve slope (S=20) and winding resistance (Rw = 0.75 Ω) are used. Other inputs were chosen as follows:

- Burden resistance Rb = 1.558 Ω, the burden due to the secondary lead impedance. This is based on a lead length of 760 feet of #10 copper wire that is similar to other known lead lengths in the substation as shown in Fig. 6, and a relay burden of 0.008 Ω for this specific model of relay.
- System X/R ratio is 30.0
- DC offset is set at 0.39 as estimated from the peak positive and peak negative values for the 1st cycle of this event, from the data measured from this CT.
- Per unit remanence is set at 0.50 as a worst-case value for remanent flux in a CT
- Symmetrical primary fault current is 2,900 A, the worst-case peak value seen in the DFR record.

The results are seen in Fig. 7. These results match the DFR record, and are expected, as 2,900 A of fault current should not saturate a 2000:5 CT, even if the fault is fully offset.
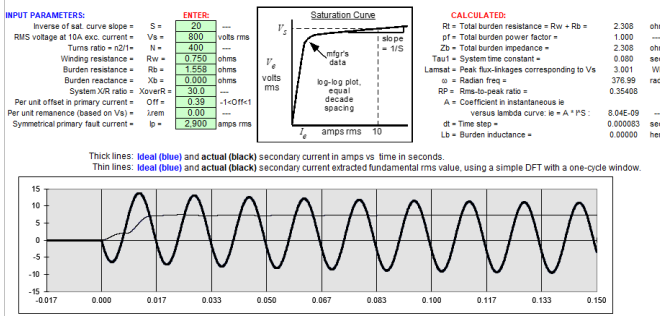
Fig. 7. Circuit Breaker 8 CT performance

1) Circuit Breakers 5 and 6 CT Performance Modeling

Breakers 5 and 6 have 3000:5 CTs that are tapped to a 2000:5 turns ratio. Using a lower tap lowers the accuracy class and saturation voltage of the CT. However, these CTs will have seen significantly lower levels of fault current (estimated to be 725 A between the two CTs based on a short circuit study) for this event, so also will not have saturated.

2) Transformer A CT Modeling

As is shown in Fig. 6, the CTs for the 138 kV side of Transformer A are a 1200:5 bushing CT tapped to a 600:5 turns ratio to supply the transformer protective relay circuits. This bushing CT is then connected to a 10:3 auxiliary CT to convert the effective CT ratio to 2000:5 to parallel with the circuit breakers 5, 6, and 8 bushing CTs into the relay. analysis of CT performance requires modeling both the bushing CT and the auxiliary CT.

3) Transformer A Bushing CT Modeling

This bushing CT is a 1200:5 CT tapped to a 600:5 turns ratio. Generic values for the saturation curve slope (S=20) and winding resistance (Rw = 0.75 Ω) are used. The burden on these CTs has been measured in the field, and these burdens are shown in Figure 6. Other inputs were chosen as follows:

- C200 accuracy class is assumed, as this is typical for transformer bushing CTs.
- Saturation voltage is set to 100 V, as half of the full tap saturation voltage.
- Burden resistance Rb = 4.080 Ω, the A-phase measured burden
- System X/R ratio is 30.0
- DC offset is set at 0.39 as estimated for the Circuit Breaker 8 CTs.
- Per unit remanence is set at 0.00
- Symmetrical primary fault current is 2,900 A, the assumed worst case peak value for this fault event. Based on data measured from the power quality recorders on the 33 kV bus.

The results are seen in Fig. 8. This CT shows some level of saturation for this fault event. Any saturation seen in this CT will be passed through the auxiliary CT to the relay.
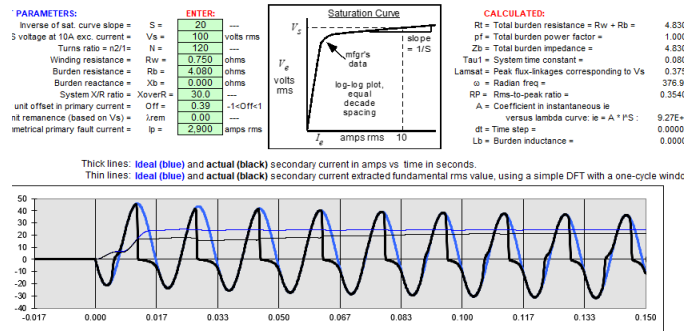

Fig. 8. Transformer A bushing CT performance

This CT will experience significant saturation for any DC offset at this level of fault current. If this CT is a C400 CT, with an effective accuracy class of C200, the CT will saturate in the presence of significant DC offset (25% or more), such as occurred in this fault.

4) Auxiliary CT modeling.

This CT is a C200, 10:3 CT. Generic values for the saturation curve slope (S=20) and winding resistance (Rw = 0.75 Ω) are used. Other inputs were chosen as follows:

- CT is a C200 as per Feeder B test results, and assuming the Feeder A auxiliary CT is identical.
- Burden resistance Rb = 0.110 Ω, the connected secondary burden for 60 feet of #10 copper, as per Fig. 6.
- System X/R ratio is 30.0
- DC offset is set at is set at 0.39 to match the other CT models
- Per unit remanence is set at 0.50 as a worst-case value.
- Symmetrical primary fault current is 24 A, the output of the transformer bushing CT for assumed worst case peak value of 2,900 A primary for this fault event.

The results are seen in Fig. 9 This CT should perform adequately for this fault event.
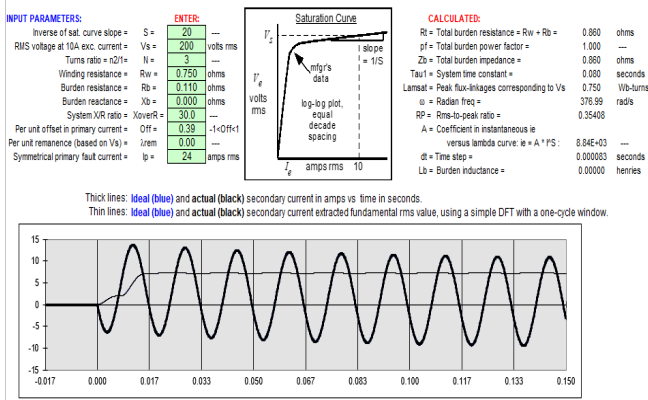
Fig. 9. Transformer A auxiliary CT performance

For this fault event, even if the auxiliary CT is a C100 CT, the CT will perform adequately, without saturation, for this fault event.

5) Analysis of the Line Differential Relay Operation

It is apparent that the saturation of the Transformer A bushing CT is the proximate cause of the line differential relay operation. However, the waveform seen by the relay is not the typical waveform of a saturated CT, such as the one in Fig. 8. The relay current can be modeled using a modified version of the CT Saturation Calculator tool, by remembering that the Transformer A bushing CT circuit is measuring the outflow of the bus to 33 kV fault (I_1 from Fig. 5), while the other three sets of CTs are measuring the inflows ($I_2 + I_3 + I_4$ from Fig. 5) to this bus section. During the periods of the cycle where the Transformer A bushing CT is saturated, no outflow to the 33 kV fault will be measured, resulting in a secondary error current seen by the relay.

This relay error current can be modeled by using the CT modeling of Fig. 8

Fig. 8. Transformer A bushing CT performance. The blue "ideal" line is the actual current flowing through the CT: I_1 of Fig. 5. This current is equal to the fault current flowing to the 33 kV bus: the sum of the currents of I_2, I_3, and I_4. (I_5 can be ignored in this simple model, as this current was approximately 70 A and has little impact.). The black "actual" line of Fig. 8 is the modeled output of the Transformer A bushing CT. Since the auxiliary CT will not normally saturate, the output of the transformer bushing CT will be passed through to the relay, so the saturation of the bushing CT will be seen by the relay. Remembering that the relay sees $I_1+I_2+I_3+I_4$, subtracting this actual current (the direct measurement of I_1) from the ideal line (the fault current flowing through the CT, $I_2+I_3+I_4$) results in the red waveform of Fig. 10. A quick visual comparison shows this modeled waveform is closely resembles the actual measured waveform of Fig. 4.
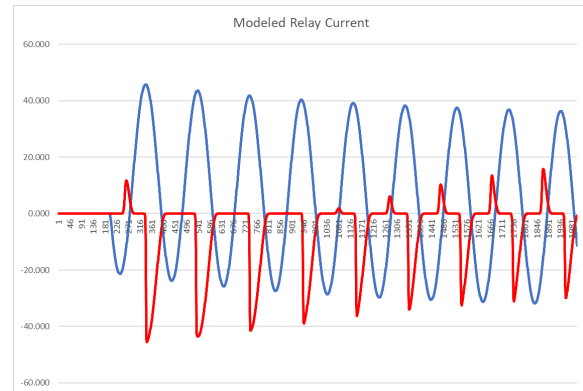

Fig. 10. Relay error current

The CT saturation calculator also provides a phasor representation of the ideal and saturated secondary current using a simple DFT calculation. Using the same logic as for the modeled relay current, subtracting the magnitude of the saturated current phasor from the magnitude of the ideal current phasor provides an estimation of the current seen by the microprocessor relay algorithms. This estimated relay current (in secondary amps) is shown in Fig. 11, and clearly exceeds the relay minimum operating setting of 720 A. The line differential algorithm will therefore operate for this fault event.

This result corresponds well to the actual fault event. Both System 1 and System 2 line differential relays on Feeder A operated, suggesting a common cause outside of the relay algorithms. The common point for both relays is the single set of transformer bushing CTs, connected through auxiliary CTs in series. The auxiliary CTs are properly dimensioned and will reproduce the fault accurately, thereby pointing at the transformer bushing CTs as the root cause.
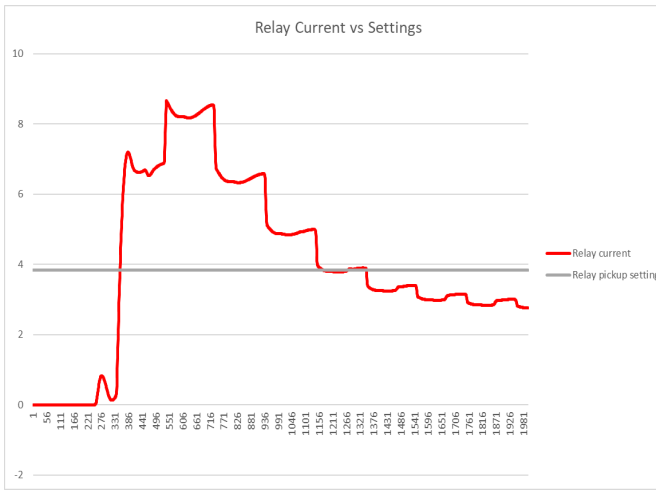
Fig. 11. Estimated phasor current seen by the relays

C. Feeder B Relay Operation Analysis

Feeder B has an identical bus arrangement to that of Feeder A. A short circuit study showed the same general distribution: most of the current contribution flows from Feeder D through Transformer B to the 33 kV bus. The peak error current seen in the System 1 relay for Feeder B is approximately 2,300 A peak. Similar CT modeling to that of the Feeder B analysis was performed with similar results: the Transformer B bushing CT will saturate for this fault event, the circuit breaker bushing CTs will not saturate, and the line differential relays will see an error current greater than the element pickup setting.

D. Transformer Differential Operation

Both Transformer A and Transformer B are protected by electromechanical transformer differential protection relays. These relays did not operate during the event. This is the desirable performance for a transformer through-fault, such as this event. However, the 138 kV bushing CT is fairly saturated, so an analysis of the transformer relay performance is warranted. From an operating perspective, the operation of the transformer differential relay would have the same result as the line differential relay operation, clearing the bus and the connected feeder to the remote substation.

For this analysis, it is necessary to model the transformer 138 kV bushing CT, as shown in Fig. 8, and the transformer 33 kV bushing CT.

1) Transformer A 33 kV bushing Ct Modeling

The 33 kV bushing CT is a 4000:5 C400 CT. Generic values for the saturation curve slope (S=20) and winding resistance (Rw = 0.75 Ω) are used. Other inputs were chosen as follows:

- Burden resistance Rb = 1 Ω, an assumed value
- System X/R ratio is 30.0
- DC offset is set at is set at 0.39 to match the other CT models
- Per unit remanence is set 0.
- Symmetrical primary fault current is 12,127 A, the 2,900 A worst case 138 kV peak current.

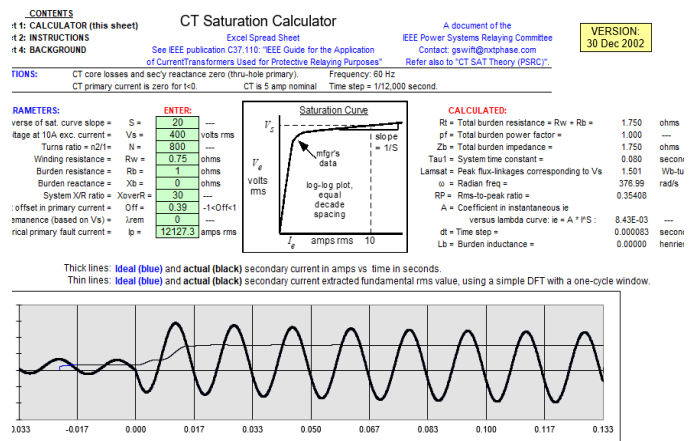The results are seen in Fig. 12. The CT performs without saturation.

Fig. 12. 33 kV bushing CT performance

2) Relay Operation Analysis

The settings for the transformer differential relays for Transformer A and Transformer B are identical. They both use a 40% slope setting and a 20% harmonic restraint setting to prevent tripping on transformer inrush during energization. The differential current I_D is the sum of the current phasors flowing in each winding of the relay, as reflected through the relay taps, and for this model of relay the restraint current I_R is the minimum individual current flowing into the relay windings.

For the simple modeling of the transformer differential performed here, the "actual" current magnitudes calculated by the CT Saturation Calculator are used. I_D is the absolute value of $I_{HV} - I_{LV}$. I_R is the minimum value of I_{HV} and I_{LV}. I_D must be greater than 40% of I_R for the relay to operate. As seen in Fig. 13 and Fig. 14, the differential current exceeded the 40% restraint characteristic in the first cycle after the fault. However, the differential relay did not operate.
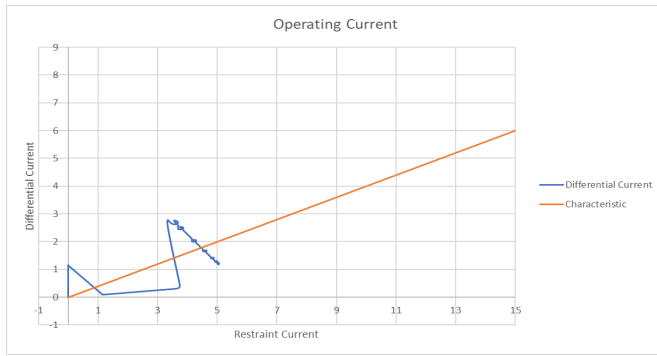
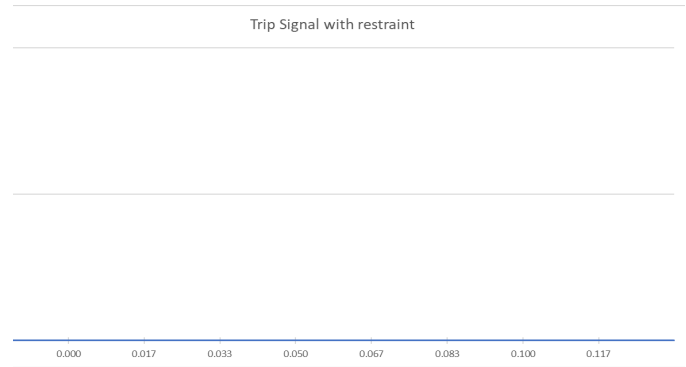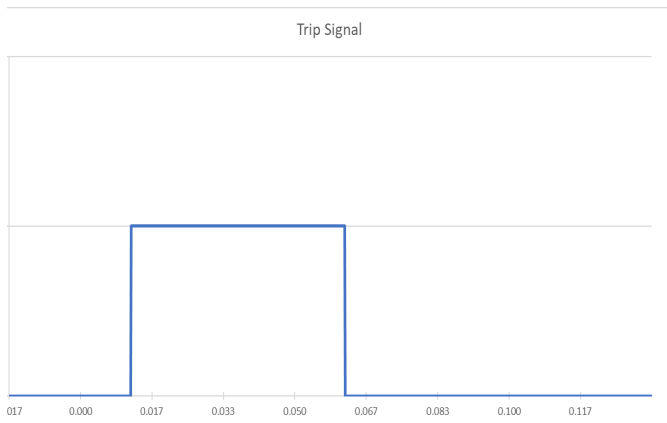Fig. 13. Transformer Relay differential current

Fig. 14. Transformer differential trip signal - no

The CT Saturation Calculator tool uses a simple one-cycle DFT to calculate the magnitude of the fundamental of the "actual" current. It is a simple exercise to modify the tool to calculate the 2nd harmonic of the "actual" current for the saturated CT. The 2nd harmonic of the current in the 138 kV CT is shown in **Error! Reference source not found.**, compared to the 20% 2nd harmonic restraint setting. This shows that the 2nd harmonic in the 138 kV CT will be present for approximately 6 cycles after the fault. The transformer differential relay would restrain for this time, as shown in Fig. 15. Therefore, the transformer differential relays didn't trip because the CT saturation in the 138 kV bushing CT was severe enough to restrain the element to a time after the line differential relays had already cleared the fault.

Fig. 15. Trip signal with harmonic restraint

E. Conclusions to relay operation analysis

The analysis of relay operation performed here is based on modeling of CTs, plus simple modeling of relay operating characteristics. Much of the data is estimated based on general knowledge and expertise. However, the modeling provides similar results in the observed data to adequately explain the operations of the line differential relays for Feeder A and Feeder B, and the transformer differential relays for Transformer A and Transformer B.

V.   EVENT TESTING AND TEST RESULTS

Modeling is only a guide to performance. The modeling done in the previous section was based on known data at the time of the fault. Another possibility is that the CT circuits are different from the design documentation, or the CTs have some performance issues, such as failing CT secondary leads. As part of the event analysis, testing of the CT circuit was performed to determine the root cause of the relay mis-operation.

The following tests were performed:

1) Secondary Circuit Burden Test
2) Current Transformer Excitation Test
3) Current Transformer and Secondary Circuit Insulation Resistance Test

Prior to performing any tests, the nameplate information of the current transformers was required to verify if the field testing results were within specification. Specifically, the full ratio, connected ratio and the class of the CT needed to be ascertained.

The main CTs on the high side bushing of the power transformer connect to both first line and second line relay protection for each 138kV transmission line.

The CT on Transformer A associated with the 138kV Feeder A has a full ratio of 600/5 (multi-ratio) and the relays are connected to the 600/5 tap. At this ratio the CT class is C200.

The CT on Transformer B associated with the 138kV Feeder B has a full ratio of 1200/5 (multi-ratio) and the relays are connected to the 600/5 tap. The test results for this CT were conducted at the connected ratio of 600/5.

The line current differential relays were not directly connected to this main CT, but in fact connected to auxiliary CTs that were connected to the 600/5 tap of the main CT. The auxiliary CTs connected to the relays have a 10/3 ratio.

Test #1 (Secondary Circuit Burden Test) was prescribed for the full circuit with all aux CTs connected. To perform the burden test the CTs were disconnected from the circuit at the closet accessible point to the CT. A current source was then connected at the point of disconnect <u>away</u> from the CTs, but still connected to the secondary circuit. Currents were applied ranging from 1A, 2A, 3A, 4A, and 5A and at each current value, the voltage was measured at those terminals. This would provide the values needed to calculate the CT secondary burden for both 138kV feeders A and B as shown below.

In order to verify the CT class, Test #2 (Current Transformer Excitation Test) was performed. This was done by performing the same steps as Test #1 but applying the connections at the terminal block <u>towards</u> the CT, thus removing the secondary circuit from the test. The results are shown below. The testing revealed that both CTs saturated above nameplate values.

Finally, Test #3 (Current Transformer and Secondary Circuit Insulation Resistance Test) was performed to verify the integrity of the complete circuit as well as the presence of a single ground. The resulting insulation resistance was measured to be greater than **500 MΩ** for the 138kV Feeder B and **28.5 MΩ** for the 138kV Feeder A, both of which are above the minimum threshold.

The end result of this testing is that with one exception for both 138kV Feeders A and B, CTs were performing within their application limits, though with a fairly high connected burden on one of the feeders. However, for each feeder the 600/5 Transformer CT saturated at an unacceptable level.

138kV Feeder B:

A Phase

Term Applied	Current Applied	Voltage Measured	Calculated Burden
B10-B20	1	3	3
B10-B20	2	6	3
B10-B20	3	9	3
B10-B20	4	12	3
B10-B20	5	15	3

B Phase

Term Applied	Current Applied	Voltage Measured	Calculated Burden
B12-B20	1	1.9	1.9
B12-B20	2	3.9	1.95
B12-B20	3	5.9	1.97
B12-B20	4	7.9	1.975
B12-B20	5	9.9	1.98

C Phase

Term Applied	Current Applied	Voltage Measured	Calculated Burden
B14-B20	1	1.5	1.5
B14-B20	2	3	1.5
B14-B20	3	4.5	1.5
B14-B20	4	6.1	1.525
B14-B20	5	7.6	1.52

Saturation Tests

Applied Volts (Vs)			Measured	
C.T. Term.	Applied Term	Volts (V)	Amps (I)	Calc Ohms (Z)
X1 - X2	2X2-2X3	25	0.0482	518.67
X1 - X2	2X2-2X3	50	0.0768	651.04
X1 - X2	2X2-2X3	75	0.0958	782.88
X1 - X2	2X2-2X3	100	0.1138	878.73
X1 - X2	2X2-2X3	125	0.1304	958.59
X1 - X2	2X2-2X3	150	0.1480	1013.51
X1 - X2	2X2-2X3	175	0.1693	886.00
X1 - X2	2X2-2X3	200	0.2133	820.44
X1 - X2	2X2-2X3	210	0.2840	704.23
X1 - X2	2X2-2X3	220	0.5732	366.36
X1 - X2	2X2-2X3	225	1.0600	207.55

Saturation Curve

Test Voltage (Insulation Resistance): 1000 Vdc for 1 min

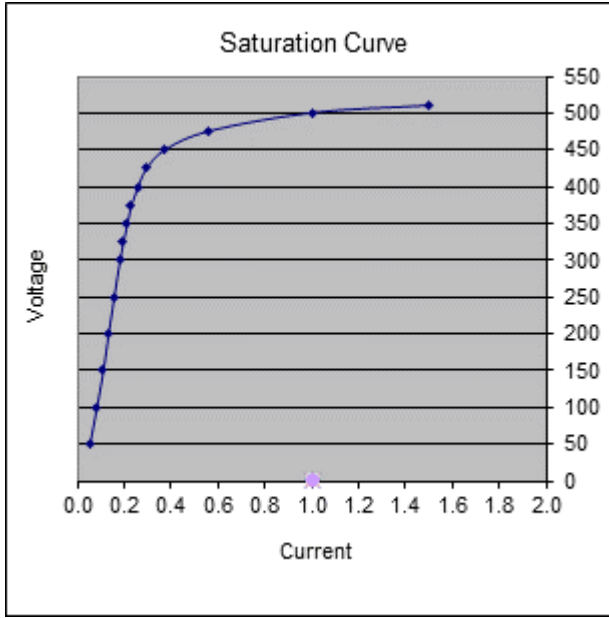| Terminal	Cubicle	M Ohms
H1-X1-Gnd	JA20	+500

138kV Feeder A:

A Phase

Term Applied	Current Applied	Voltage Measured	Calculated Burden
3X2 - 1X3	1	4.140	4.140
1X2 - 1X3	2	8.258	4.129
1X2 - 1X3	3	12.229	4.076
1X2 - 1X3	4	16.170	4.043
1X2 - 1X3	5	20.051	4.010

B Phase

Term Applied	Current Applied	Voltage Measured	Calculated Burden
2X2 - 1X3	1	2.450	2.450
2X2 - 1X3	2	4.855	2.428
2X2 - 1X3	3	7.222	2.407
2X2 - 1X3	4	9.506	2.377
2X2 - 1X3	5	11.775	2.355

C Phase

Term Applied	Current Applied	Voltage Measured	Calculated Burden
1X2 - 1X3	1	2.540	2.540
1X2 - 1X3	2	5.050	2.525
1X2 - 1X3	3	7.750	2.583
1X2 - 1X3	4	10.360	2.590
1X2 - 1X3	5	12.750	2.550

Saturation Tests

Applied Volts (Vs)			Measured	
C.T. Term.	Applied Term	Volts (V)	Amps (I)	Calc Ohms (Z)
X2 - X3	B9-Gnd	50	0.0530	943.40
X2 - X3	B9-Gnd	100	0.0820	1219.51
X2 - X3	B9-Gnd	150	0.1100	1363.64
X2 - X3	B9-Gnd	200	0.1320	1515.15
X2 - X3	B9-Gnd	250	0.1560	1602.56
X2 - X3	B9-Gnd	300	0.1810	1657.46
X2 - X3	B9-Gnd	325	0.1960	1530.61
X2 - X3	B9-Gnd	350	0.2130	1525.82
X2 - X3	B9-Gnd	375	0.2300	1521.74
X2 - X3	B9-Gnd	400	0.2580	1453.49
X2 - X3	B9-Gnd	425	0.2960	1351.35
X2 - X3	B9-Gnd	450	0.3740	1136.36
X2 - X3	B9-Gnd	475	0.5610	802.14
X2 - X3	B9-Gnd	500	1.0000	475.00
X2 - X3	B9-Gnd	510	1.5000	340.00

Saturation Curve

Test Voltage (Insulation Resistance): 1000
Vdc for 1 min

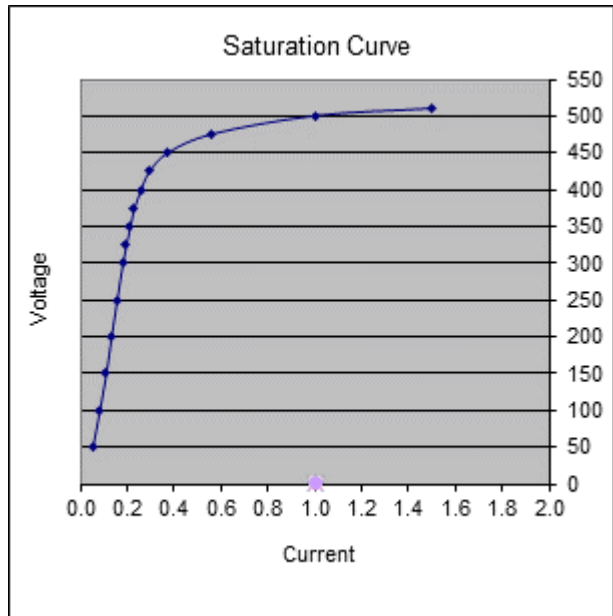| Terminal	Cubicle	M Ohms
H1-X1-Gnd	JA20	28.5

VI. CORRECTIVE ACTION PLAN

The root cause of the undesirable relay operations is the use of under-dimensioned CTs located at the transformer bushings, paralleling multiple CTs inputs, and with a high connected burden on these same CTs.

The initial recommendation was to perform a complete relay upgrade project. However, due to budgetary and outage availability constraints, this course of action was not achievable.

De-sensitizing the protective setting may prevent undesirable operations for some fault events but are unlikely to prevent operations for all fault events. A better solution is to directly address CT performance through different CTs or different protection schemes. Therefore, based on this analysis, we make two specific recommendations:

1) Adjust the line differential relay settings as much as practical to reduce the likelihood of undesirable operations for similar fault events.
2) Consider changes to the CTs or relaying schemes to address CT performance.

A. Line Differential Elements Settings Modification

The minimum differential operating current setting was raised from 720 A to 2,300 A for the 138kV Feeders A and B. As per the analysis of the original settings, the 720 A setting is not adequate to prevent undesirable operations of the line differential relays for similar fault events. Prior to the settings modification fault studies were performed. Based on the results the new setting was implemented.

B. Transformer Bushing CTs Removal from the Lines Differential Protection Scheme

Next a modification that will address the issues but at the same time maintain security and dependability were looked into.

In order to address the mixed matched externally summed CT's as well as the poor undersized CT performance that contributed to the misoperations of the two 138kV Feeders A and B, the contribution from Transformers A and B 600/5 bushing CTs were removed from the relays at the local substation.

Fault studies were performed and system contingencies were considered, including maximum transformer load, transformer through fault currents and transformer inrush, prior to the settings modifications implementations. Analysis confirmed that de-sensitizing the relays did not impact protection security and dependability.

VII. LESSONS LEARNED

This paper has presented a misoperation case study to highlight lessons learned on application of current transformers – a recurring theme through the history of relaying. The rules have evolved as multi-input low-burden microprocessor relays are predominantly in service today, yet underlying basics remain. The experiences reported here underscore these recommendations:

1) Avoid wired parallel connections of CTs to sum currents. Use relays with separate CT inputs and internal numerical combination of the measurements – these relays will achieve the most accurate measurements and will do the best job of recognizing and mitigating CT saturation.

2) Make the effort to install or retrofit CTs of appropriate accuracy class and ratio for protection of a zone, instead of using auxiliary CTs to interface a misfit or adjacent-zone CT into the scheme.

3) Assess CT accuracy and performance during the design phase. CT performance for maximum fault current, worst expected dc offset, tap used, and relay characteristics must be evaluated using methods presented in this paper or from text sources cited in references.

4) For ongoing development of CT applications, reduce system protection department evaluation workload by establishing standard CT application categories according to protection zone type and system voltage class. Categories may be defined by specified minimum CT secondary voltage rating or accuracy class at the tap used, maximum fault current, dc offset time constant or X/R ratio, maximum allowed CT secondary burden including wiring, and error-current tolerance of the relay used with specific settings specified. If a large percentage of typical applications fall within category limits, the CT evaluation calculation has in effect already been made for all of them.

5) Specify standard CTs with high secondary voltage rating or accuracy class, along with use of full taps, as a part of design standards for new and retrofit installations. This makes it easier to define broad application categories that minimize department evaluation workload along with risk

of saturation-induced misoperations.

6) If a particular installation crosses category boundaries, carry out calculations to determine CT and scheme performance at the extreme fault scenarios. It may prove necessary to modify the installation according to the above rules to minimize risk of CT saturation and misoperation.

7) If pre-existing CTs and wiring are reused, thoroughly check wiring condition, insulation performance, burden, and circuit grounding connections during commissioning.

8) Develop standard relay setting criteria, especially for differential relays, to minimize misoperation risk if CTs or schemes don't perform as expected for a fault. Sensitivity should not be set much greater than needed for actual fault situations. With percentage differential characteristics, take advantage of the relay's ability to curtail unneeded sensitivity when any zone-boundary fault current is high.

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BIOGRAPHIES

Vered Talmor-Pulley received a Bachelor of Science degree in Electrical Engineering from Rochester Institute of Technology. She has 16 years' experience in the electric power industry including positions at Emerson Process Management, General Electric, and Con Edison where she's worked for more than 10 years. At Con Edison, she's held positions in one of the generating stations, and in central engineering in control systems project as well as in relay protection. She is currently a senior engineer in the Protection and Support Engineering Section.

Ed W. Chen graduated from City University of New York with a Bachelor of Science in Electrical Engineering Science and from Worcester Polytechnic Institute with a Master of Science in Electrical and Computer Engineering. Ed joined National Grid New York in 2010. In 2012, he became a Relay Protection Engineer in their Protection Analysis and Relay Project Engineering groups. In 2016, Ed joined Consolidated Edison Company of New York, Inc. and continues to work

there as a Relay Protection Engineer. In 2022, Ed was promoted to the Section Manager of Protection Support & Analysis in Consolidated Edison Company of New York, Inc. Ed is a registered Professional Engineer in the state of New York.

Daniel Taft received a Bachelor of Engineering degree in Electrical Engineering from Stevens Institute of Technology and a Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute. He has 42 years' experience in the electric power industry including positions at General Electric, Hubbell, the Federal Energy Regulatory Commission, and Con Edison where he's worked for more than 30 years. At Con Edison, he's held positions in Relay Protection Engineering, System Operations, and Transmission Planning. He is current the Chief Engineering of the Protection and Controls Engineering Department. He is a Professional Engineer in the State of New York.

William Winters, PE has 20 years of experience in the electric utility industry and Con Edison. He has held positions of increasing responsibility in substation and system operations and engineering, and served as the chief engineer of electrical engineering from 2015 – 2021. Currently he serves as the chief engineer for the protective relay strategy team which is responsible for P&C standards, asset management and technology planning. William earned his BSEE and MSEE from Manhattan College, is a member of IEEE and CIGRE, and is a registered Professional Engineer in New York State.

Benny J Varughese received a Bachelor of Science in Electrical Engineering from Drexel University and a Master of Science in Electrical Engineering from Manhattan College. Benny joined ConEdison Co. of New York in 2002. From 2002 - 2012, he was a Equipment and Field Engineer supporting Substations Operation. From 2012 - 2015, Benny worked as a Supervisor of the Protective Systems Relay Testing Group. From 2015 - 2019, Benny was working as a Section Manager of the Protection System Testing Group. From 2019 - 2020, Benny worked as a Substations Commissioning Engineering for North American Protection and Control. From 2020 to now, Benny has been a Senior Engineer for ConEdison Co. of NY in the Protective Relay Strategy and Implementation Group.

Rich Hunt, MS, PE, has over 30 years of experience in the electric power industry, emphasizing protective relaying. Over the last 15 years, his focus has been on all aspects of specifying and designing digital substations, including IEC 61850, process

bus, non-conventional instrument transformers, networking, and time synchronization.

Rich earned his BSEE and MSEE from Virginia Tech, is a Senior Member of IEEE, a member of the Main Committee of the IEEE Power System Relaying & Control Committee, and is a registered Professional Engineer

Eric A. Udren has over 50 years of experience leading the design and application of protective relaying systems, substation control, wide-area monitoring and control systems, phasor measurement unit (PMU) applications, and communications systems. Eric is an IEEE Life Fellow, holds 12 US patents, and is the author of over 100 papers and book chapters including Westinghouse's Applied Protective Relaying. Eric was the Industry Guru of PAC World Magazine in September 2016. He was elected in 2019 as a member of the National Academy of Engineering "for leadership in advancing protection technologies for electric power grids."