January 5, 2000

EA 99-319

Mr. A. Alan Blind
Vice President - Nuclear Power
Consolidated Edison Company of
New York, Inc.
Indian Point 2 Station
Broadway and Bleakley Avenue
Buchanan, NY 19511

SUBJECT: RESULTS OF THE ENFORCEMENT FOLLOWUP INSPECTION TO THE AUGMENTED INSPECTION TEAM (AIT), NRC INSPECTION REPORT 05000247/99014

Dear Mr. Blind:

This letter transmits the results of a safety inspection conducted by Mr. D. Dempsey at your Indian Point 2 reactor facility from November 15 to November 19, 1999. The purpose of the inspection was to determine your compliance with NRC rules and regulations associated with the reactor trip with complications that occurred on August 31, 1999. The results of the inspection were communicated to your staff at an exit meeting conducted by telephone on December 7, 1999.

As previously stated in the AIT report, the August 31, 1999, event posed no immediate threat to the public health and safety. It was, however, risk significant. The event involved a loss of offsite power to all four of the 480 Volt vital buses, an additional loss of the emergency diesel generator that supplied one of those buses (along with other important accident mitigation equipment), and the depletion of one of the four station batteries. The event was preventable, and was caused primarily by poor performance in the areas of configuration management (e.g., design and test control) and corrective action.

Based on the results of this inspection, five apparent violations were identified and are being considered for escalated enforcement action in accordance with the “General Statement of Policy and Procedure for NRC Enforcement Actions” (Enforcement Policy), NUREG-1600. The apparent violations involve: (1) inadequate corrective action for over-temperature/delta-temperature instrument problems, (2) 10 CFR 50, Appendix B, Criterion III design control for load tap changers and undervoltage relay pickup settings, (3) Technical Specification (TS) 3.7.B.3 for inoperable 138 KV offsite power, (4) TS 3.7.B.1 for the 23 emergency diesel generator being inoperable, and (5) 10 CFR 50, Appendix B, Criterion XI test control regarding Amptector trip units.

The event that occurred on August 31, 1999, was preventable. Existing programs for review of procedures, post-maintenance testing, design review, implementation of license conditions, and equipment maintenance and surveillance failed to identify the major issues that caused or contributed to the risk significance of the event. Prior opportunities existed to have identified and corrected several of the problems, such as the unnecessary over-temperature/delta-temperature trip during reactor protection system maintenance, the incorrect emergency diesel generator output breaker trip setting, and operation of the station auxiliary transformer load tap changer in the manual mode. In our preliminary enforcement deliberations, we determined that it is not likely that you deserve credit for identification of the conditions that resulted in the apparent violations. Therefore, it is likely that a civil penalty will be assessed for the apparent violations.

You conducted several comprehensive reviews that identified the root causes of the event, and took short-term corrective actions that were adequate to support the safe restart of the plant. More programmatic, long-term corrective actions are contained in your recovery plan, that will be subject to future NRC inspections. Therefore, in our preliminary enforcement deliberations, we determined that you will likely be given credit for corrective actions.

Please be advised that the number and characterization of the apparent violations described in the enclosed inspection report may change as a result of further NRC review. You will be advised by separate correspondence of the results of our deliberations on this matter.

The circumstances surrounding the apparent violations, the significance of the issues, and the need for lasting and effective corrective actions were discussed with your staff on several occasions. On September 14, 1999, you presented the findings of your self-assessments of the event and planned recovery actions to the NRC staff at a meeting conducted at our King of Prussia office. A summary of our Augmented Inspection Team's conclusions regarding the causes, safety implications, and your staff's actions prior to and during the August 31 event was presented to you at a public exit meeting on September 27, 1999. Our followup inspection, conducted between September 21 and October 15, 1999, evaluated your short-term corrective actions and other self-assessment activities. We presented the interim results of that inspection to you at a site departure briefing at your facility on October 15, 1999, and our preliminary conclusions were provided to you in our letter dated October 12, 1999. The results of that inspection were provided to you with our letter dated December 21, 1999.

As a result of our interactions with you and your staff, we believe that we have sufficient information concerning the root causes, short-term corrective actions, and long-term recovery plans on which to base our enforcement decisions. Consequently, we believe that neither a predecisional enforcement conference nor a written response to the apparent violations addressed in this inspection report is needed. Please contact Mr. J. Rogge at 610-337-5146 within seven days of the date of this letter to notify the NRC should you decide to request a predecisional enforcement conference or to respond in writing to the apparent violations discussed in this report. If you choose to respond in writing, your response should be clearly marked as a "Response to Apparent Violations in Inspection Report No. 50-247/99-14," and should be submitted within 30 days of the date of this letter.

Also based on this inspection, we have determined that two Severity Level IV violations of NRC requirements occurred. These violations involve: (1) four examples of failure to establish or implement procedures, and (2) a technical specification violation governing the operability of the essential service water system. These violations are being treated as Non-Cited Violations (NCVs), consistent with Section VII.B.1.a of the Enforcement Policy (64 FR 61142, November 9, 1999). If you contest these violations, or their severity levels, you should provide a written response within 30 days of the date of this inspection report, with the bases for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region I, the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001, and the NRC Resident Inspector at the Indian Point Unit 2 facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if applicable, will be placed in the NRC Public Document Room.

Sincerely,

ORIGINAL SIGNED BY
BRIAN E. HOLIAN FOR:

Wayne D. Lanning, Director
Division of Reactor Safety

Docket No. 05000247
License No. DPR-26

Enclosure: Inspection Report 05000247/99014

cc w/encl:
J. Groth, Senior Vice President - Nuclear Operations
J. Baumstark, Vice President, Nuclear Power Engineering
J. McCann, Manager, Nuclear Safety and Licensing
B. Brandenburg, Assistant General Counsel
C. Faison, Director, Nuclear Licensing, NYPA
J. Ferrick, Operations Manager
C. Donaldson, Esquire, Assistant Attorney General, New York Department of Law
P. Eddy, Electric Division, Department of Public Service, State of New York
T. Rose, NFSC Secretary
F. William Valentino, President, New York State Energy Research and Development Authority
J. Spath, Program Director, New York State Energy Research and Development Authority

<u>Distribution w/encl</u>:
H. Miller, RA/J. Wiggins, DRA (1)
D. Screnci, PAO, (2)
Nuclear Safety Information Center (NSIC)
PUBLIC
NRC Resident Inspector
Region I Docket Room (w/concurrences)
J. Rogge, DRP
S. Barber, DRP
L. Harrison, DRP
R. Junod, DRP
W. Lanning, DRS
B. Holian, DRS
W. Ruland, DRS
D. Dempsey, DRS
DRS File

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J. Harold, NRR
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Inspection Program Branch, NRR (IPAS)
R. Correia, NRR
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REGION I

Docket No.	05000247
License No.	DPR-26
Report No.	05000247/99014
Licensee:	Consolidated Edison Company of New York, Inc.
Facility:	Indian Point 2 Nuclear Power Plant
Location:	Buchanan, New York
Dates:	November 15 - 19, 1999
Inspector:	D. Dempsey, Reactor Inspector, NRC Region I
Approved by:	William H. Ruland, Chief Engineering Support Branch Division of Reactor Safety

EXECUTIVE SUMMARY

Indian Point 2 Nuclear Power Plant
NRC Inspection Report No. 05000247/99014

This inspection involved the enforcement aspects of the activities associated with the reactor trip with complications that occurred at Indian Point Unit 2 on August 31, 1999. The inspection followed an NRC Augmented Inspection Team review of the event and its causes, and a followup inspection of Consolidated Edison Company's corrective actions and recovery plans. The results of those inspections are documented in Inspection Report Nos. 50-247/99-08 and 50-247/99-13. Several violations of NRC requirements were identified during this inspection.

Operations

Because an appropriate procedure did not exist, condition monitoring of No. 24 station battery was not performed as required by Technical Specification (TS) 4.6.C.1 when No. 24 battery charger was lost. Failure to establish a procedure for performing a surveillance test required by the technical specifications was the first example of a non-cited violation of TS 6.8.1. (O1.1)

During the August 31, 1999, loss of offsite power event, operators exceeded the limiting condition for operation of TS 3.3.F.1.b concerning operability of the essential service water system. Failure to cool down the plant within the required time was a non-cited violation of the TS. (O1.2)

Failures to operate the turbine-driven feedwater system in accordance with the system operating procedure when feed regulating valve FCV-405D failed open on loss of power, and to document the deviation in a condition report were the second and third examples of a non-cited violation of TS 6.8.1. (O8.1)

Lack of procedures for responding to and recovering from loss of a single 480 Volt vital bus was a contributing factor in the untimely restoration of offsite power to the vital buses during the August 31 event. This was the fourth example of failure to establish and implement procedures as required by TS 6.8.1. (O8.2)

Maintenance

ConEd did not adequately disseminate or evaluate conditions adverse to quality associated with the over-temperature/delta-temperature instruments in the reactor protection system. Failure to implement effective corrective action for erratic operation of the channel 4 OTΔT instrument directly contributed to a risk-significant plant trip and loss of offsite power event, and was an apparent violation of the corrective action requirements of 10 CFR 50, Appendix B, Criterion XVI. (M2.1)

Engineering

Though not a direct cause of the event, correct 480 Vac undervoltage relay pickup settings are important to meet the plant design basis requirement to minimize unnecessary transfers of the 480 Vac buses from the normal offsite supply to the emergency diesel generators. Failure to establish appropriate undervoltage relay pickup settings when modification EGP-91-06786-E was implemented was the first example of an apparent violation of the design control requirements of 10 CFR 50, Appendix B, Criterion III. (E1.1)

Operation of the station auxiliary transformer load tap changer in the manual mode placed the plant outside of its licensing basis and directly contributed to the loss of offsite power to the four 480 Vac vital buses. Failure to translate applicable regulatory requirements and the design basis into procedures was the second example of an apparent violation of the design control requirements of 10 CFR 50, Appendix B, Criterion III. Extended power operation with the 138 Kilovolt electrical system inoperable was an apparent violation of TS 3.7.B.3. (E8.1)

An inadequate calibration and test procedure resulted in miscalibration of the 23 emergency diesel generator output breaker in May 1999. During the August 31, 1999, loss of offsite power event, the breaker tripped when bus 6A loads started, resulting in loss of the bus. Power operation in excess of seven days with an inoperable emergency diesel generator was an apparent violation of TS 3.7.B.1. Failure to implement an adequate test program to assure satisfactory operation of the breakers’ Amptector trip units was an apparent violation of the test control requirements of 10 CFR 50, Appendix B, Criterion XI. (E8.2)

Report Details

EVENT OVERVIEW

Synopsis of Event: Plant trip with complications

At 2:31 p.m. on August 31, 1999, the Consolidated Edison (ConEd) Indian Point Unit 2 reactor automatically tripped from 99% power on a reactor protection system over-temperature/delta-temperature (OTΔT) signal. About three minutes later, normal offsite power to all four of the 480 Volt ac (Vac) vital buses was lost and all three emergency diesel generators (EDGs) started and re-energized the buses. A few seconds thereafter, the No. 23 EDG output breaker tripped open, de-energizing 480 Vac bus 6A. With the bus were lost one of the two motor driven auxiliary feedwater (AFW) pumps, No. 24 station battery charger, redundant emergency core cooling components and other equipment. Approximately seven and one-half hours later, No. 24 station battery discharged to the point where No. 24 118 Vac instrument bus de-energized, causing a loss of more than 75% of the central control room alarms for safety-related equipment. ConEd declared an Unusual Event at 9:55 p.m. Bus 6A was re-energized from No. 23 EDG at 12:43 a.m on September 1, and offsite power to the remaining 480 Vac buses was restored by 3:00 am. Normal power was restored to bus 6A and No. 23 EDG was shutdown at 10:08 p.m.

Event Significance

During the event reactor decay heat was removed using the steam generators and the main condenser. In this type of transient, the AFW system is an important mitigating factor. Only one AFW pump is needed to remove the design decay heat load successfully. Steam generator levels were maintained with one motor-driven and one turbine-driven pump. Depletion of No. 24 station battery failed a feedwater regulating valve to the open position, but the turbine-driven pump remained available and continued to be used intermittently to provide makeup water.

If the AFW system had been unavailable, other options to remove decay heat existed. The 6.9 Kilovolt (KV) system remained energized and either the main feedwater or condensate system could have been used to feed the steam generators. Bus 6A also could have been re-energized and No. 23 motor driven AFW pump used if the others had failed. The ability to feed and bleed the primary system through the pressurizer power-operated relief valves (PORVs) or the reactor head vents was degraded by the loss of the 6A bus. Since Indian Point Unit 2 is not analyzed for only one PORV, no credit for this method of decay heat removal was given in the risk analysis.

Conditional core damage probability (CCDP) is used to estimate the risk significance of conditions or events. The NRC and ConEd risk analyses had similar results. The estimates were conservative because no credit for feed and bleed was applied, No. 23 motor driven AFW pump was assumed to be unavailable, and a low success probability was assigned for operators maintaining steam generator levels with the main feedwater system. The calculated CCDP was 2.0×10^{-4}, making this event risk significant.

O1 Conduct of Operations

O1.1 Monitoring of No. 24 Station Battery

a. Inspection Scope (92901)

The inspector reviewed the operators' efforts to monitor the condition of No. 24 station battery following loss of the No. 24 battery charger during the August 31 event.

b. Observations and Findings

During the event, 480 Vac vital bus 6A was de-energized when the No. 23 EDG output breaker tripped open. Loss of bus 6A de-energized No. 24 station battery charger placing No. 24 118 Vac instrument bus (and other direct current loads) on the associated station battery. Technical Specification (TS) 3.7.A.6.b states that a battery charger may be inoperable up to 24 hours if the surveillance requirements of TS 4.6.C.1 are initiated within one hour and repeated every eight hours thereafter. The surveillance frequency is to be maintained until the battery is declared inoperable or the charger is declared operable. The purpose of the surveillance test is to provide the operator with information to assess the condition of the battery. It requires measuring and recording individual cell voltages, specific gravity and temperature of the pilot cell, and battery terminal voltage.

The operating shift crew was aware of the TS requirement to monitor battery condition, and requested that the surveillance be performed. Procedure PT-M22, "Station Battery," provides the instructions to perform the surveillance. Step 2.1 of the procedure states that the test may be performed regardless of plant operating status. However, the procedure presumes that a battery charger is providing a nominal output of 130 Vdc to its associated battery. The test and performance group determined that procedure PT-M22 was not appropriate for performing the readings while the battery was discharging, and requested guidance from management on how to proceed. ConEd concluded that the inability to take the required readings was a missed surveillance that required the battery to be declared inoperable and the actions of TS 3.0.1 to be followed. Although the operators did not log the fact, No. 24 battery was declared inoperable about 3:30 p.m. on August 31, 1999.

In lieu of all of the readings prescribed by the TS, test personnel started monitoring and reporting battery terminal voltage to the control room at approximately 5:30 p.m. The readings were reported hourly until 8:15 p.m., and every 30 minutes thereafter until 11:35 p.m., by which time the battery was no longer capable of supplying loads. The readings provided at least some limited information to the operators concerning the condition of the battery.

Technical Specification 6.8.1.a requires written procedures to be established covering the activities referenced in Appendix A of Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operation).” The regulatory guide specifies written procedures for startup, operation, and shutdown of safety-related systems such as emergency power sources, and procedures for combating emergencies and other significant events such as loss of electrical power or degradation of power supplies.

c. Conclusions

Because an appropriate procedure did not exist, condition monitoring of No. 24 station battery was not performed as required by TS 4.6.C.1 when No. 24 battery charger was lost. Failure to establish a procedure for performing a surveillance test required by the technical specifications was the first example of a violation of TS 6.8.1. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (64 FR 61142, November 9, 1999). This violation is in the licensee’s corrective action program as CR 199907080. (**NCV 50-247/99-14-01**)

O1.2 Untimely Initiation of Plant Cooldown

a. Inspection Scope

The inspector reviewed the technical specification (TS) concerning when plant cooldown to less than 350° Fahrenheit was required during the August 31 event.

b. Observations and Findings

As documented in Licensee Event Report 50-247/99-15, operators considered TS 3.0.1 to be the most restrictive, or limiting, plant specification following the loss of multiple emergency core cooling system components associated with 480 Vac bus 6A. TS 3.0.1 required the plant to be in the cold shutdown condition within 30 hours of reaching hot shutdown. Since hot shutdown was achieved when the plant tripped, cold shutdown would have been required within 30 hours of the trip.

The licensee’s post-event utility assistance team identified that the operators missed a more limiting requirement. TS 3.3.F.1.b required the reactor coolant system to be cooled down below 350°F by six hours after the plant trip (hot shutdown) if an essential service water header was not restored within 12 hours of hot shutdown in the event that fewer than three essential service water pumps were available. This requirement was not met, since the plant was not cooled down to less than 350°F until 4:45 p.m. on September 1.

c. Conclusions

During the August 31 loss of offsite power event, operators exceeded the limiting condition for operation of TS 3.3.F.1.b concerning operability of the essential service water system. Failure to cool down the plant within the required time was a violation of the TS. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (64 FR 61142, November 9, 1999). This violation is in the licensee's corrective action system as CR 199906747. (**NCV 50-247/99-14-02**)

O8 Miscellaneous Operations Issues

O8.1 (Closed) Unresolved Item 50-247/99-13-06: Turbine Driven Auxiliary Feedwater Pump Operation and Emergency Diesel Generator Monitoring

Turbine Driven Auxiliary Feedwater Pump Operation

During the August 31 event, steam generator levels were maintained using No. 21 motor- driven AFW pump and No. 22 turbine-driven AFW pump. The turbine-driven pump provided makeup water to No. 23 steam generator through feed regulating valve FCV-405C and to No. 24 steam generator through feed regulating valve FCV-405D. By 9:55 p.m., seven hours and 20 minutes after the event began, No. 24 station battery voltage dropped to about 105 Vdc causing the static inverter that supplied power to No. 24 118 Vac instrument bus to shutdown. As designed, valve FCV-405D failed open when the instrument bus de-energized, and at 10:03 p.m. the operators shutdown the turbine-driven pump.

Section 4.14 of system operating procedure (SOP) 21.3, "Auxiliary Feedwater System Operation," provides instructions for taking local manual control of a failed open feed regulating valve to control steam generator water level. The procedure also requires (in step 4.7.4) the feed regulating valves to be shut after shutting down the turbine-driven pump. Because operations personnel were engaged in efforts to restore bus 6A, shift management elected to deviate from the procedure by leaving valve FCV-405D open. Batch additions to the steam generators were made in this manner at 10:57 p.m. and 11:49 p.m. on August 31.

The operators anticipated loss of No. 24 instrument bus as the station battery depleted, and were aware of the procedure steps pertaining to valve FCV-405D. Thus, there was adequate time to have processed a temporary procedure change to operate the turbine-driven pump in the desired manner before the valve failed open. Subsequently, had adequate management support been available, a procedure change could have been made between the time the bus was lost and the need to feed the steam generators arose. The inspector concluded that a decision to deviate from the procedure should not have become necessary during the event.

In deviating from the SOP, ConEd failed to meet the requirement of TS 6.8.1 that procedures be established and implemented. If plant conditions did not allow following procedures as written, ConEd could have used the procedure change processes allowed by TS 6.8.2 or 6.8.3. In an emergency, when action immediately is needed to protect the public health and safety, and there is not sufficient time to implement the change process, the licensee can invoke the latitude allowed by 10 CFR 50.54(x).

The requirements of 10 CFR 50.54(x) regarding procedure adherence are paraphrased in Section 4.3 of Station Administrative Order (SAO) 133, "Procedure, Technical Specification, and License Adherence and Use Policy," and Section 4.4.2 of Operations Administrative Directive (OAD) 33, "Procedure Use and Adherence." The inspector found that another section (4.4.1) of OAD-33 also addresses procedure adherence. This section states that operations personnel have the authority to deviate from procedures when required to protect the public health and safety, plant personnel, or to prevent damage to equipment, and is derived from Section 5.2 of ANSI Standard 18.7-1976, which is referenced in TS 6.8.1. A decision to deviate from a procedure must be reported to the operations manager, the plant manager, or the vice president of nuclear power and documented in a condition report.

The inspector observed that Section 4.4.1 allowed some latitude in addition to that permitted by 10 CFR 50.54(x) and Section 4.4.2 of OAD-33. ConEd initiated condition report 199909197 to evaluate and resolve the apparent conflict between ANSI 18.7-1976, Section 4.4.1 of the OAD, and 10 CFR 50.54(x).

Failures to operate the turbine-driven AFW system in accordance with SOP 21.3, and to document the deviation in a condition report per OAD-33 are the second and third examples of a violation of the TS 6.8.1 requirement that procedures be established and implemented. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (64 FR 61142, November 9, 1999). The violations are in the licensee's corrective action program as CRs 199909197 and 199907401. (**NCV 50-247/99-14-01**)

<u>Emergency Diesel Generator Monitoring</u>

After No. 21 and No. 22 EDGs automatically started and energized their respective electrical buses, operators were dispatched to monitor the machines in accordance with step 4.1.12 of Abnormal Operating Instruction (AOI) 27.1.1, "Loss of Normal Station Power." In Inspection Report 50-247/99-08, the NRC augmented inspection team found that the operators were knowledgeable in EDG and support system operations and were on hand to respond to local alarms or abnormal conditions. However, the operators did not recognize a requirement to take periodic log readings per DSR-24, "Emergency Diesel Generator Logs." In CR 199907439, ConEd concluded that the logs were not taken because plant procedures did not provide clear instructions to do so following an automatic, vice a manual, EDG start.

AOI 27.1.1 references SOP 27.3.1, "Emergency Diesel Generator Manual Operation," as an interfacing procedure. Notes in SOP 27.3.1 require hourly DSR-24 log readings to be taken during EDG operation. Since the AOI referenced the SOP, the inspector concluded that the AOI required the readings to be taken. Failure to take the hourly EDG log readings was a violation of minor significance and is not subject to formal enforcement action.

O8.2 <u>(Closed) Unresolved Item 50-247/99-13-01: Procedures for Loss of a Single 480 Volt Bus</u>

When No. 23 EDG output breaker tripped on August 31, the ensuing loss of voltage on 480 Vac vital bus 6A coincident with the plant trip signal locked out all supplies to the bus. Loss of either vital bus 5A or 6A is a "blackout" condition at Indian Point 2, which provides a trip signal to the normal offsite supply breakers to all four of the 480 Vac vital buses. With bus 6A de-energized, undervoltage interlocks prevented resetting the blackout logic and closing the normal supply breakers from the 6.9 KV buses. Thus, the blackout logic had to be defeated to restore offsite power to buses 2A, 3A, and 5A.

About eight hours were devoted in part to developing the instructions and temporary facility changes needed to restore power to bus 6A and reset the blackout logic. Lack of procedures for responding to and recovering from loss of a single 480 Vac bus was a contributing factor in the untimely restoration of offsite power to the vital buses during the event. Failure to establish and implement procedures for loss of a single 480 Vac vital bus was the fourth example of a violation of TS 6.8.1. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (64FR 61142, November 9, 1999). This violation is in the licensee's corrective action system as CR 199906643. (**NCV 50-247/99-14-01**)

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 <u>Spurious Over-Temperature/Delta-Temperature Trip</u>

a. <u>Inspection Scope (92902)</u>

At 2:21 p.m. on August 31, a spurious trip of the reactor protection system (RPS) channel 4 OTΔT instrument occurred while corrective maintenance was being performed on the channel 3 OTΔT instrument. The coincidence of two out of four OTΔT trip signals automatically tripped the reactor and initiated the event. The inspector reviewed the circumstances prior to the reactor trip.

b. <u>Observations and Findings</u>

Condition reports (CRs) documented problems with the channel 4 OTΔT instrument prior to the August 31 event. For example, in January 1999, the instrument setpoint was found to be lower than normal (CR 199900467). In July, a loop 4 OTΔT bistable failed when a 118 Volt ac vital inverter transferred to its alternate source (CR 199905224). The conditions were categorized at the lowest priority level in the corrective action system (level 4), which do not require tracking or trending. In addition, numerous instances of spurious alarms and channel trips on the RPS overpower/delta temperature instruments had been occurring during the year. In its root cause evaluation of the August 31 event, ConEd concluded that plant personnel had been de-sensitized to spurious alarms. On August 26, five days prior to the event, channel 4 tripped unnecessarily. This occurrence was documented in level 4 CR 199906545, which the plant corrective action group closed to “track and trend.” The information was not disseminated adequately to all operating shifts or the work control group which is responsible for planning and scheduling maintenance. The low significance assigned to OTΔT instrument problems and poor communication across the plant organization resulted in the decision on August 31 to continue with previously planned maintenance on the channel 3 instrument.

c. Conclusions

ConEd did not adequately disseminate or evaluate conditions adverse to quality associated with over-temperature/delta-temperature instruments in the reactor protection system. Failure to implement adequate corrective action for erratic operation of the channel 4 OTΔT instrument directly contributed to a risk-significant plant trip and loss of offsite power event, and was an apparent violation of the corrective action requirements of 10 CFR 50, Appendix B, Criterion XVI. (**EEI 50-2467/99-14-03**)

E1 Conduct of Engineering

E1.1 480 Vac Vital Bus Undervoltage Relay Pickup Settings

a. Inspection Scope (92903)

The inspector reviewed the extent to which ConEd’s failure to establish pickup (reset) settings for the 480 Vac vital bus undervoltage relays contributed to the August 31 event.

b. Observations and Findings

The degraded voltage relays are designed to ensure sufficient voltage on the 480 Vac vital buses to start and run safety-related equipment. A sustained bus undervoltage condition (longer than 180 ±30 seconds) initiates isolation of the affected bus from its normal offsite supply and re-energization from the associated EDG.

ConEd replaced the original Westinghouse model SV relays with high accuracy Asea Brown Boveri Type 27N electronic relays, and raised the undervoltage trip settings from 403 Vac to 421 Vac under modification EGP-91-06786-E. The NRC approved License Amendment No. 165 on September 22, 1993, and the modification was implemented in 1995. Information that ConEd provided to the NRC in support of the license amendment included calculation EGP-00110-00, “Summary of Degraded Voltage Study,” which showed a degraded voltage relay pickup (reset) setting of 429 Vac.

The original relays did not have adjustable pickup settings, as do the Type 27N relays. Modification EGP-91-06786-E did not establish pickup settings, and none were implemented in 1995 when the relays were calibrated and installed. Calibrations performed in June 1997 using procedure PT-R61, “480 Volt Breaker Undervoltage Relays,” likewise did not include calibration of the reset points.

During the August 31 event, with the station auxiliary transformer load tap changer (LTC) in the manual mode of operation, a sensed low voltage condition on the 480 Vac vital buses initiated a transfer to the EDGs. After the event, in calculation FEX-00119-00, “480V Bus Blackout Analysis During the August 31, 1999 Incident,” ConEd determined the transient and final (recovered) voltages on the buses. ConEd also tested the relays to identify the actual reset values. The calculation and tests confirmed that the final bus voltages were not high enough to have reset the undervoltage relays with the LTC in the manual mode. Following the event, ConEd revised modification EGP-91-06786-E to establish a relay reset value at 2.6 Vac above the dropout setting; i.e. at 423.6 Vac.

Had the August 31 plant trip occurred with the new reset values in place, the event’s consequences may not have been as severe. Buses 3A and 6A probably would have remained energized but buses 2A and 5A likely would have separated from their normal offsite supplies. However, if the automatic LTC had been available on August 31, voltage on all of the 480 Vac buses would have recovered enough to reset the undervoltage relays even with the pre-event pickup settings. Thus ConEd’s failure to establish undervoltage relay pickup settings in 1995 contributed to, but did not directly cause, the event.

c. <u>Conclusions</u>

Though not a direct cause of the event, correct 480 Vac bus undervoltage relay pickup settings are important to meet the plant design basis requirement to minimize unnecessary transfers of the 480 Vac buses from the normal offsite supply to the EDGs. Failure to establish appropriate undervoltage relay pickup values when modification EGP-91-06786-E was implemented in 1995 was the first example of an apparent violation of the design control requirements of 10 CFR 50, Appendix B, Criterion III in that plant design was not translated into procedures. (**EEI 50-247/99-14-04**)

E8 Miscellaneous Engineering Issues

E8.1 <u>(Closed) Unresolved Item 50-247/99-13-02: Station Auxiliary Transformer Load Tap Changer Operation</u>

The station auxiliary transformer load tap changer (LTC) is designed to prevent unnecessary transfers of the 480 Vac vital buses to the onsite emergency power supplies (EDG). In the automatic mode of operation, the LTC senses the output of the transformer and initiates a tap change cycle to maintain nominal voltage on the 6.9 KV buses that normally supply the 480 Vac buses.

The LTC was placed in the manual mode on September 9, 1998, when ConEd identified that it was not maintaining the selected station auxiliary transformer output voltage (nominally 7.1KV). On August 31, 1999, the LTC was unable to respond automatically to the decrease in transformer output that occurred when the unit main generator tripped off line. The resulting extended voltage drop on the 480 Vac buses actuated sustained degraded voltage relays that initiated transfer of the buses to the EDGs.

Procedures did not require the LTC to be operated in the automatic mode. For example, System Operating Procedure (SOP) 27.1.1, "Operation of 345KV and 138KV Components," directed transfer of tap changer control to automatic if desired (emphasis added), and SOP 1.3, "Reactor Coolant Pump Startup and Shutdown," contained the option of returning the LTC to automatic or restoring bus voltage in manual. The discretion was contained in some design calculations as well. For example, calculation EGP-00109-00, "Analysis On the Movement of the Automatic Load Tap Changer For the 138/6.9KV Station Auxiliary Transformer," stated that the LTC may be returned to automatic after starting large loads at the operator's discretion.

The LTC could have been repaired and returned to automatic operation before August 31. Condition report 199807874 was initiated when the LTC problem initially was identified. The CR was categorized as a priority level 4 issue that requires no response, tracking, or trending. In February 1999, the condition was assigned a higher priority when it was classified as a control room deficiency, and corrective maintenance was scheduled for March. However, at that time, original replacement parts were unavailable. Engineering approved the use of an alternate replacement part in June, and the work was scheduled monthly thereafter. The work control group deferred the replacement for higher priority jobs on several occasions.

ConEd did not recognize that automatic operation of the LTC was part of the plant licensing basis. In September 1992, ConEd requested a license amendment to raise the 480 Vac vital bus sustained degraded voltage setpoint from 403 Vac to 421 Vac. The change supported new calculated minimum terminal voltages to start and run 480 Vac safety equipment motors. The request stated that, "The load tap changer will act to raise voltage within the time delay for the degraded voltage relay actuation setpoint."

In response to an NRC request for additional information dated February 19, 1993, ConEd provided calculation EGP-00110-00, "Summary of Degraded Voltage Study." The calculation contained an analysis of fast 6.9KV bus transfers and predicted minimum 480 Vac vital bus voltages after a plant trip with and without a coincident safety injection signal. The analysis stated that the LTC would "...automatically adjust the voltage on the 6.9 KV and 480V buses."

Based in part on the information provided in ConEd's February 1993 response, the NRC approved ConEd's request in a safety evaluation report (SER) for license amendment No. 165, dated September 22, 1993. The modification was implemented in February 1995. System operating procedures were not revised at that time to ensure that the LTC was operated in the automatic mode, or that appropriate compensatory measures were taken to ensure the operability of the 138 KV offsite power system with the LTC in manual. Failure to translate regulatory requirements and the design basis into procedures was the second example of an apparent violation of the design control requirements of 10 CFR 50, Appendix B, Criterion III. (**EEI 50-247/99-14-04**)

Manual operation of the LTC directly contributed to the loss of offsite power event on August 31. ConEd calculation FEX-00119-00, “480V Bus Blackout Analysis During the August 31, 1999 Incident,” concluded that in the best case (bus 6A), voltage dropped to 391 Vac before stabilizing at 432 Vac. The 480 Vac vital bus degraded voltage relays did not reset within the design time delay, which timed out at about 168 seconds. Had the LTC been in automatic, voltage would have stabilized at approximately 467 Vac and reset the degraded voltage relays, preventing the loss of offsite power event. Between September 9, 1998 and August 31, 1999, with the LTC in the manual mode without appropriate compensatory measures, the 138 KV offsite power system was inoperable. Power operation greater than 24 hours with the offsite power system inoperable was an apparent violation of Technical Specification 3.7.B.3. (**EEI 50-247/99-14-05**)

E8.2 (Closed) Unresolved Item 50-247/99-13-03: No. 23 Emergency Diesel Generator Output Breaker Overcurrent Trip Setting

The plant trip and sustained undervoltage condition on the 480 Vac vital buses initiated a transfer of the buses to their respective EDGs. About 14 seconds after the 23 EDG output breaker closed onto bus 6A, the breaker tripped due to a short time overcurrent condition. De-energization of bus 6A resulted in loss of power to one of two motor-driven auxiliary feedwater pumps, No. 24 station battery charger, one of two power operated relief valve block valves and reactor head vent valves, and other redundant emergency core cooling system equipment. The condition complicated ConEd’s recovery efforts and contributed significantly to the risk of the event.

The EDG output breaker is a Westinghouse model DB-75 breaker that uses a solid state overcurrent protective device called an Amptector. The short time overcurrent trip is designed for fault protection. The required short time overcurrent trip setting was 6000 Amperes (A) ±2% of setting. ConEd’s calibration and test methodology was not adequate to set the overcurrent trip setting reliably.

The Amptector was calibrated using an Amptector test kit and a secondary current injection method. With a current transformer (sensor) ratio of 3000/5 and a desired trip setting of 6000A, the specified short time pickup setting was 9.8A to 10A. The specification required using a relatively coarse adjustment at the bottom of the high range (10-60A) tester. At 10A the adjustment was not precise enough to ensure that the breaker would trip within the acceptance band. In addition, the licensee stated that, under the circumstances, the actual current at breaker trip may be lower than is indicated on the test kit.

ConEd missed an earlier opportunity to have identified the incorrect Amptector setting. In 1997, a residual heat removal pump breaker was found to have an incorrect current transformer ratio setting. Following a root cause analysis, a corrective action item was opened to implement primary current injection testing of Westinghouse model DB-50 and DB-75 breakers. The corrective action was not intended to address potential shortcomings with the secondary current injection calibration method, which were not readily apparent at the time. However, had the proposed corrective action been implemented, the miscalibration of the 23 EDG output breaker may have been identified in May 1999 when the Amptector was last calibrated.

Subsequent to the August 31 event, ConEd found that the 23 EDG output breaker was tripping at about 3200A. This trip setting is below the starting current that would be expected as bus 6A loads sequence onto the EDG. The condition existed since May 27, 1999, when the Amptector was calibrated, and rendered No. 23 EDG inoperable. Power operation in excess of seven days with an inoperable EDG was an apparent violation of Technical Specification 3.7.B.1. (**EEI 50-247/99-14-06**)

Criterion XI of 10 CFR 50, Appendix B, requires implementation of a test program to assure that testing required to demonstrate satisfactory performance of safety-related components is identified and performed. ConEd's failure to implement an adequate test method to ensure the proper trip setting of the No. 23 EDG output breaker was an apparent violation of this test control requirement. (**EEI 50-247/99-14-07**)

E8.3 (Closed) Unresolved Item 50-247/99-13-08: Emergency Diesel Generator Load Sequence
(Closed) Unresolved Item 50-247/99-13-09: Emergency Diesel Generator Load Sequencing Time Delay Relay Tolerance

During the August 31, 1999, event, No. 23 EDG output breaker tripped on a short-time overcurrent condition. The breaker trip was caused by a combination of an incorrect breaker Amptector setting (see Section E8.2) and a simultaneous (or near simultaneous) start of 480 Vac vital bus 6A loads.

The original design plant trip/station blackout EDG load sequence started No. 23 component cooling water, No. 23 auxiliary feedwater, and No. 23 service water pumps 11, 12, and 20 seconds after EDG breaker closure, respectively. The setting tolerance of the electro-pneumatic (Agastat) relays was ±2 seconds. Overlap of the time delay relay settings caused by the tolerance made possible a simultaneous start of the component cooling and auxiliary feedwater pumps, with a combined starting current of about 3500 Amperes (A). In 1997 ConEd implemented modification FPX-91-06757-F, which replaced all but one of the Agastat relays with Tempo electronic relays. The relays were calibrated to within ±0.5 seconds with a design tolerance of ±2% of setting (less than two seconds combined). The blackout timer for the auxiliary feedwater pump was not replaced, and its setting remained between 10 to 14 seconds. The modification reduced (but did not eliminate) the potential for simultaneous pump starts. The modification also changed the service water pump time delay from 20 seconds to 15 seconds. Considering the worst-case combination of relay calibration error, drift, and time to peak pump current, it became possible for the service water pump to start as the auxiliary feedwater pump starting current reached its maximum value. The combined starting current is about 4200A. Thus the modification reduced the likelihood of a simultaneous component cooling water/auxiliary feedwater pump start, but increased the possibility of an auxiliary feedwater pump/service water pump interaction. However, in neither case would the starting currents have challenged a properly calibrated EDG output breaker Amptector with a worst-case trip setting tolerance of 5520A to 6480A.

During the August 31 event, the plant computer did not record operation of the 480 Vac bus load breakers, and there was no direct indication of the actual post-trip loading sequence for No. 23 EDG. However, since the EDG output breaker tripped 14 seconds after closing, it is likely that the breaker tripped on the combined starting currents of the component cooling water and auxiliary feedwater pumps. The breaker trip just as likely would have occurred under the original sequencing design. The inspector was unable to conclude that the 1997 EDG sequencer relay modification contributed to the loss of the 6A vital bus. While the original and post-1997 sequencer designs were not optimal, the inspector identified no inconsistencies with the design basis and no violation of NRC requirements. Unresolved item 50-247/99-13-08 is closed.

The Tempo Series 812 time delay relays are accurate to ±2% of setting over their operating range, and were calibrated to ±0.5 seconds. For the longest time delay in the EDG loading sequence, the range is ±1.4 seconds. The load sequence time delay acceptance criterion in refueling surveillance test PT-R13, “Safety Injection System,” is ±2 seconds. The criterion was based on the setpoint tolerance of the original Agastat relays, and was not changed when the Agastat relays were replaced with more accurate electronic timers under modification FPX-91-06757-F. While not documented in the modification package, ConEd considered changing the procedure acceptance criterion when the relays were replaced. However, since the existing criterion remained adequate to satisfy the requirements of the EDG loading studies, it was retained. The inspector concluded that the criterion was acceptable for the purposes of the surveillance test. No violation of NRC requirements was identified concerning this aspect of the modification. Unresolved item 50-247/99-13-09 is closed.

X1 Exit Meeting Summary

The inspector presented the interim inspection results at members of Consolidated Edison management at a briefing held on November 19, 1999. An exit meeting subsequently was held by telephone on December 7, 1999. ConEd acknowledged the preliminary inspection findings. No proprietary information was examined or used during the inspection.

PARTIAL LIST OF PERSONS CONTACTED

Consolidated Edison

A. Blind	Vice President, Nuclear Power
J. Baumstark	Vice President, Nuclear Engineering
R. Masse	Plant Manager
D. Parker	Maintenance Manager
R. Eifler	Section Manager, System Engineering Electrical/I&C
J. Tuohy	Section Manager, Plant Engineering
P. Schoen	Shift Manager, Operations
G. Hinrichs	Section Manager, Root Cause Analysis
H. Sager	Manager, Nuclear QA and Oversight
R. Allen	Section Manager, Regulatory Affairs
J. Maris	Westinghouse Corporation

Nuclear Regulatory Commission

W. Raymond	Senior Resident Inspector
B. Holian	Deputy Division Director, Division of Reactor Safety
J. Rogge	Chief, Branch 2, Division of Reactor Projects

INSPECTION PROCEDURES USED

92901	Followup, Operations
92902	Followup, Maintenance
92903	Followup, Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-247/99-14-01	NCV	Failure to establish and implement procedures required by TS 6.8.1 (4 examples)
50-247/99-14-02	NCV	Violation of essential service water TS 3.3.F.1.b
50-247/99-14-03	EEI	Criterion XVI violation - inadequate corrective action for OTΔT instrument problems
50-247/99-14-04	EEI	Criterion III design control violation - load tap changer and undervoltage relay pickup settings (two examples)
50-247/99-14-05	EEI	Violation of TS 3.7.B.3 - 138 KV offsite power inoperable
50-247/99-14-06	EEI	Violation of TS 3.7.B.1 - No. 23 EDG inoperable
50-247/99-14-07	EEI	Criterion XI test control violation - Amptector trip units

Closed

50-247/99-13-01	URI	ConEd did not have a procedure for recovery of a 480 volt bus following a loss of power
50-247/99-13-02	URI	Control of the station load tap changer in manual prior to the event on August 31, 1999 was not evaluated for effect on offsite power supply
50-247/99-13-03	URI	Failure to control the overcurrent setting of EDG breaker 23. This URI became EEIs 50-247/99-14-06 and 07.
50-247/99-13-06	URI	ConEd started and stopped the TDAFW pump turbine and did not monitor the EDGs during operation on August 31
50-247/99-13-08	URI	ConEd did not evaluate moving the service water pump sequence timer closer to the component cooling pump and AFW pump starting times during the Blackout EDG loading; and did not replace the AFW electro-hydraulic timing relay with a solid state timer or evaluate the combined effect
50-247/99-13-09	URI	ConEd did not adjust the acceptance criterion for the installed AFW solid state timer

LIST OF ACRONYMS USED

A	Amperes
AFW	Auxiliary Feedwater
ANSI	American National Standards Institute
CFR	Code of Federal Regulations
ConEd	Consolidated Edison
CR(s)	Condition Report(s)
EDG(s)	Emergency Diesel Generator(s)
EEI	Escalated Enforcement Item
LTC	Load Tap Changer
OAD	Operations Administrative Directive
OTΔT	Over-Temperature/Delta-Temperature
SER	Safety Evaluation Report
SAO	Station Administrative Order
SOP	System Operating Procedure
TDAFW	Turbine Driven Auxiliary Feedwater
Vac	Volts Alternating Current
Vdc	Volts Direct Current