October 19, 1999

Mr. A. Alan Blind
Vice President - Nuclear Power
Consolidated Edison Company of
New York, Inc.
Indian Point 2 Station
Broadway and Bleakley Avenues
Buchanan, NY 10511

SUBJECT: NRC AUGMENTED INSPECTION TEAM - REACTOR TRIP WITH COMPLICATIONS - REPORT NO. 50-247/99-08

Dear Mr. Blind:

On September 27, 1999, the NRC completed an Augmented Inspection Team (AIT) at the Indian Point Unit 2 (IP2) Station. The enclosed report (Enclosure 1) presents the results of that inspection.

The AIT was chartered (Enclosure 2) to review the causes, safety implications, and your staff's actions involving the reactor trip with complications at IP2 on August 31, 1999. The NRC noted that the event was complicated by unexpected system interactions that involved safety-related equipment. The team reviewed the record of activities that occurred, interviewed plant personnel, and conducted plant walkdowns. The team developed a sequence of events, determined the causes and risk significance of the event, and assessed the quality of response by the plant staff and management. A summary of the team's findings was presented at a public exit meeting on September 27, 1999. The NRC briefing slides from that meeting are provided in Enclosure 3.

Although there was no immediate threat to public health and safety, the event was risk significant. The event involved a loss-of-offsite power to all four of the 480 volt vital buses, the additional loss of the emergency diesel generator supplying one of those buses (along with some other risk-significant equipment), and the depletion of one of the four safety-related batteries. Other than one cell of the depleted battery needing replacement, there was no damage to plant equipment. Additionally, there was no radiological release due to the event.

The team determined that the event was preventable and was caused primarily by problems in plant configuration control. Contributing to these were some notable weaknesses in the corrective actions and technical support areas. In addition, weaknesses in management oversight during the event contributed to the delay in restoring normal electrical power supplies.

Configuration control problems included the station auxiliary transformer load tap changer being left in a position contrary to licensing bases. This led to a loss of offsite power to the vital buses following the plant trip. Poor control of emergency diesel generator output breaker short time over-current trip settings, compounded by a deficiency with the timing of the sequencing relays for some safety-related loads, caused the loss of emergency power to one of the vital buses.

Weaknesses were also noted in management oversight of the station's response to the event. Management did not promptly recognize the significance of the degrading conditions associated with the event. Managers appeared to focus primarily on developing shutdown work plans and schedules instead of establishing and prioritizing activities to restore plant equipment and to limit further risk. As a result of these weaknesses, station personnel provided poorly coordinated and untimely support to plant operators in restoring normal electrical power. Likewise, the post-trip response organization did not provide support to operations in the review of plant conditions relative to the emergency plan. As such, station personnel did not recognize that the declaration of an Unusual Event was missed when offsite power was lost to all 480 volt vital buses.

Shortly following the event, you presented the findings of your own self-assessments. These findings and planned recovery actions were presented to NRC staff in a meeting on September 14, 1999. Your reviews were self-critical and your findings regarding initial event response were similar to those of the AIT. Review of recovery actions was assigned to another NRC team which will document its assessments separately.

In accordance with NRC procedures, the AIT charter did not include the determination of compliance with NRC rules and regulations or the recommendation of enforcement actions. Those aspects will be addressed in subsequent inspections or reviews.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room (PDR).

Sincerely,

ORIGINAL SIGNED BY:
JAMES T. WIGGINS FOR:

Hubert J. Miller
Regional Administrator
Region I

Enclosures:
1. NRC Augmented Inspection Report No. 50-247/99-08
2. NRC Augmented Inspection Team (AIT) Charter
3. NRC Briefing Slides - September 27, 1999 Exit Meeting

Attachments:
1. Sequence of Events and Organization Response Time Line
2. Event and Causal Factors Chart

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REGION I

Docket No.:	50-247
License No:	DPR-26
Report No:	50-247/99-08
Licensee:	Consolidated Edison Company of New York Broadway and Bleakley Avenues Buchanan, NY 10511
Facility:	Indian Point Station Unit 2
Location:	Broadway and Bleakley Avenues Buchanan, NY 10511
Dates:	September 2 - 27, 1999
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Approved by:	William H. Ruland, Chief Engineering Support Branch Division of Reactor Safety Team Manager

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EXECUTIVE SUMMARY

Indian Point Unit 2 Station
NRC Inspection Report 50-247/99-08

An NRC Augmented Inspection Team (AIT) reviewed the causes, safety implications, and associated licensee actions as a result of a reactor trip on August 31, 1999. The trip was complicated by a loss-of-offsite power to all four vital 480 volt (V) buses and a loss of emergency power, the emergency diesel generator, to one of the four buses. As a result of the loss of all power to bus 6A, safety-related battery 24 was eventually depleted, resulting in a declaration of an Unusual Event.

Event Summary/Significance

Although there was no immediate threat to public health and safety, the event was risk significant. The loss-of-offsite power to the four vital 480 V buses caused the emergency onsite power sources, the emergency diesel generators, to be challenged. Emergency onsite power to one of the buses, bus 6A, was lost due to its diesel generator output breaker tripping open. Plant risk increased, because the de-energization of bus 6A caused the unavailability of power to: some emergency core cooling equipment; one motor-driven auxiliary feedwater pump; one normally closed pressurizer power-operated relief valve (PORV) block valve; and the automatic control of one auxiliary feedwater flow control valve.

This event did not cause a radiological release or any damage to plant equipment; the 24 battery was in a degraded state due an excessive discharge. Therefore, there were no actual consequences to public health and safety.

Operator performance during the event was mixed. Although operators accomplished emergency operating procedures well, performance weaknesses were noted in communications, entries into technical specifications limiting conditions for operation (LCOs), and actions related to the discharge of the 24 battery.

Configuration Control

Weaknesses in plant configuration control were the primary causes of this event. Offsite power was lost to the vital buses because the station auxiliary transformer load tap changer was not in the "Automatic" position when the trip occurred. Since September 1998, the load tap changer was not in the "Automatic" position, contrary to the plant licensing basis.

In addition, emergency power was lost to vital bus 6A because the short time over-current setting for the EDG 23 output breaker was set incorrectly, significantly below the design basis setting. Contributing to the loss of bus 6A was that the timing of the sequencing relays for safety loads was not properly selected, allowing for the potential for multiple loads to attempt to load on to the emergency diesel generator at the same time.

Management Oversight

Management oversight of and response to the event were weak in several respects. Actions during and following the event were not focused on understanding and limiting further risk to the plant, but instead were focused on developing shutdown work plans and schedules. Senior plant management did not establish clear expectations that recovery from the degraded plant conditions was a priority over preparations for shutdown work activities.

Consequently, recovery actions were poorly coordinated. Equipment restoration plans and contingency planning were not clearly understood or fully developed. Support provided by the engineering and maintenance organizations was not fully effective. Plans to develop temporary facility changes for alternate power supply were untimely and, thus, did not prevent depletion of battery 24 and the subsequent loss of most of annunciators. In addition, troubleshooting activities for bus 6A were not well planned, preventing the timely restoration of emergency power to bus 6A.

Corrective Actions

Instances of poor or ineffective use of the corrective action process contributed to the events leading to the plant trip with complications. Station personnel did not take prompt action or fully evaluate some equipment problems for their potential impact on plant operation.

For example, station personnel did not develop root causes for prior anomalies and deficient conditions associated with the reactor protection system Over Temperature/ Delta Temperature signal. The absence of a thorough investigation, establishment of root causes, and implementation of effective corrective actions led to the initiation of the event.

In addition, a load tap changer material problem was not evaluated for operability and safety impact in September 1998. The repair for this problem was not completed as of the time of the event.

Finally, station personnel missed a potential, earlier opportunity to identify a breaker Amptector test methodology problem. Corrective actions for previous breaker problems, which addressed test methodology, had not been completed by the due date listed in the corrective action report.

Technical Support

The event revealed instances, both preceding and during the event, in which the support provided to plant operators by various departments was weak. The reactor protection system anomalies were not properly communicated between among operations, engineering, and maintenance organizations. The 480 V degraded voltage relay reset setting was not properly translated into test procedures by engineering and maintenance organizations. The licensing bases of the load tap changer was not translated into plant procedures by licensing and engineering organizations. The emergency plan procedure was deficient because it did not contain adequate information for declaring an Unusual Event when offsite power is unavailable to the 480 V vital buses. Lastly, during the event, engineering and maintenance did not prevent the depletion of battery 24.

Report Details

1.0 EVENT OVERVIEW

1.1 Synopsis of Event: Reactor Trip with Complications

On August 31, 1999, at 2:31 p.m., the Indian Point Unit 2 reactor automatically shutdown (tripped) from 99% power. The reactor protection system (RPS) trip indication was Over-Temperature Delta-Temperature (OTΔT). About three minutes after the reactor trip, the normal offsite power breakers to all four 480 Volt (V) vital buses tripped unexpectedly, and all three emergency diesel generators (EDGs) started and began to assume loads on their respective 480 V buses. A short time later, the 23 EDG output breaker tripped, leaving the 6A vital bus de-energized. This resulted in a loss of power to one of the two motor-driven auxiliary feedwater (MDAFW) pumps, battery charger 24, some emergency core cooling components, and other equipment. The bus remained de-energized while technicians prepared tagouts and checked for a suspected faulted condition which could have caused the loss of power. Battery 24 subsequently discharged in about seven hours resulting in a loss of power to the direct current (dc) loads on dc panel 24 and the loads on 118 Volt alternating current (ac) Instrument Bus 24. The de-energization of the instrument bus caused a loss of most of the control room annunciators for various safety related systems, which required the declaration of an Unusual Event at 9:55 p.m.

On September 1, 1999, at about 1:00 a.m., vital bus 6A was re-energized by the 23 EDG and restoration of its loads was begun. By 9:00 p.m., normal offsite power had been restored to all the 480 V buses and the three EDGs had been secured.

The Augmented Inspection Team (AIT) developed a detailed sequence of events based on interviews and review of plant logs, computer data, and recorded information. The sequence of events is provided as Attachment 1.

1.2 Summary of Augmented Inspection Team Activities

On September 2, the AIT started the inspection. The team was tasked with reviewing the causes, safety implications, and associated licensee actions as a result of the reactor trip and subsequent complications. The NRC was concerned that the event was complicated by significant, unexpected system interactions that involved safety related equipment. Specifically of concern were: the adequacy of vital bus power restoration efforts, which led to the complication of a loss of instrument power, and the adequacy of the licensee's response to the events. The inspection was conducted in accordance with the team's charter and NRC Inspection Procedure 93800, "Augmented Inspection Team."

The team completed its onsite activities on September 10, and conducted a briefing on the status of the inspection. Team members also participated in a meeting, open to the public, between NRC staff members and ConEd staff at the NRC Region I Office on September 14, 1999. The AIT completed its activities and presented the preliminary findings of the inspection to ConEd management, in a meeting open to public observation, on September 27, 1999.

2.0 EVENT SIGNIFICANCE

Following the plant trip, reactor decay heat was removed using the steam generators and the main condenser. Water level was maintained in the steam generators using the motor-driven and turbine-driven auxiliary feedwater pumps. One of two motor-driven pumps and the turbine-driven auxiliary feedwater pump remained available throughout this event. Following battery depletion, the turbine-driven auxiliary feedwater pump feed regulating valve to one of the steam generators failed open, as designed. While this presented an additional challenge to the operators, the pump remained available for makeup to the steam generators. Only one of the two available auxiliary feedwater pumps was required to successfully remove decay heat. A properly functioning auxiliary feedwater system is important in mitigating plant transients such as this event.

In the unlikely event that the auxiliary feedwater water system failed to function, the operators had several options for removing decay heat. Since the 6.9 kV buses remained energized by offsite power, the main feedwater or condensate systems could have been used to maintain water level in the steam generators. In retrospect, the 6A bus also could have been re-energized and the #23 motor-driven auxiliary feedwater pump used in the event that the other two pumps had failed. If the main feedwater and auxiliary feedwater systems became unavailable, the operators could have removed decay heat by using a primary system cooling method referred to as "bleed and feed." This method of cooling, which involves adding water and removing steam through pressurizer power-operated relief valves (PORVs), would have been degraded by the inability to open one of the two normally closed PORV block valves. This valve could not be opened because power for this valve would have come from the de-energized 6A 480 V bus. Since opening both valves is necessary for optimal heat removal, credit was not given for this mode of core cooling in the analysis of this event.

The results of the licensee and NRC risk evaluations of this event were similar. The risk estimates were conservative in that no credit was given for "bleed and feed" cooling, the #23 auxiliary feedwater pump was considered unrecoverable, and a low probability of success was assigned for the operators using the feedwater system to provide make-up to the steam generators. Based on these conservative assumptions, the calculated conditional core damage probability (CCDP) was $2x10^{-4}$. The CCDP is used to estimate the risk significance of conditions or events.

3.0 EVENT CAUSAL FACTORS AND ROOT CAUSES

The team independently analyzed the event using "Event Causal Factors and Root Cause Analysis" techniques to determine the primary and contributing causes. The team used an event and causal factors charting methodology as a tool for its assessment. The event and causal factors chart is provided in Attachment 2.

The team's analysis identified six important equipment issues and personnel errors which directly or indirectly contributed to this event. These items are listed below with a brief explanation:

Reactor Protection System Channel 4 OTΔT spurious signal:
The spurious signal initiated the event.

Station auxiliary transformer load tap changer in "Manual":
This condition was a primary cause of the event. It led to an extended voltage drop on the 480 V buses, causing actuation of degraded voltage relays and a loss-of-offsite power to the buses.

EDG 23 output breaker overcurrent trip setting was too low:
This equipment condition caused the output breaker to trip open as pump motor loads were sequencing on the 6A bus.

EDG 23 blackout sequencer timing tolerance allowed multiple pumps to start at the same time:
The inappropriate sequencer timing allowed high starting currents to be sensed by the output breaker and contributed to the EDG output breaker tripping.

Emergency Plan procedure deficiency regarding declaring an Unusual Event when offsite power to the 480 V buses was lost for greater than 15 minutes:
This was a contributing factor to the event because this Unusual Event declaration was missed. The declaration could have provided an earlier opportunity for management to focus on restoring to the degrading plant conditions.

Station Management did not focus engineering and support personnel on plant recovery:
This was a contributing factor, because the actions and activities by support personnel did not reflect a coordinated emphasis on plant restoration.

The team concluded that the key issues listed above, as well as other items of lesser significance, revealed problems in four broad areas: Configuration Control; Management Oversight; Corrective Actions; and Technical Support.

The primary causes of the event were attributed to inadequacies in configuration control. The loss of bus 6A and subsequent degradation of plant conditions were caused by two equipment configuration control problems: the station auxiliary transformer load tap changer in the "Manual" position; and the improper overcurrent trip setting for emergency diesel generator 23 output breaker. In both cases, station personnel failed to ensure the equipment configuration was controlled as specified in the licensing and design bases.

The team also concluded that challenges in Management Oversight were significant contributing causes for the event. Station management missed significant opportunities to recognize and fully assess the degrading plant conditions, and failed to establish viable plans and contingencies for plant restoration.

4.0 PLANT RESPONSE: EQUIPMENT AND PERSONNEL

4.1 Equipment Response

The reactor trip event was complicated because a few important plant components did not function as expected or as designed. Each of these equipment issues is discussed in detail in the following sections.

4.1.1 Reactor Protection System (RPS)

The reactor trip occurred as I&C personnel were performing maintenance on RPS Channel 3, with the Over Temperature / Delta Temperature (OTΔT) bistable in the tripped condition. A spurious, unexpected trip of Channel 4 OTΔT completed the logic for a reactor trip. The OTΔT parameter protects the core from a high temperature condition and derives its signals from the reactor hot and cold leg temperatures, reactor axial power differential, and pressurizer pressure. The cause of the spurious OTΔT trip had not been determined at the completion of the AIT.

There had been precursors of the spurious bistable trip in the Channel 4 OTΔT circuit. The latest spurious signal occurred on August 26, 1999, just five days preceding this reactor trip. Information from that precursor, although entered into the IP2 condition reporting system, was not adequately categorized and distributed to all operating crews. Further, the anomaly was not communicated to work control personnel for consideration in planning work or testing activities on other channels of the reactor protection system. Therefore, the condition was not considered or evaluated by appropriate plant personnel for its impact as a potential transient risk. The lack of significance assigned to this deficient condition and poor communication both within and across organizational boundaries resulted in a less than fully informed decision to proceed with the originally scheduled testing and subsequent corrective maintenance on the reactor protection system (RPS).

Station personnel failed to recognize and evaluate a potential trend in reactor protection system (RPS) problems associated with the OTΔT circuitry. These may have been over-shadowed by more frequent intermittent actuation of the Channel 4 Over Power / Delta Temperature alarm. Spurious trips, bistable failures, and unexplained decreases in the OTΔT setpoint had all been noted and documented during the previous several months. The issues were reviewed and dispositioned by a number of individual condition reports. However, station personnel missed the opportunity to recognize these issues in the aggregate and fully evaluate these issues in a comprehensive manner. The lack of a thorough investigation, establishment of root cause(s), and implementation of effective corrective actions for prior precursors contributed to the occurrence of this event.

Engineering personnel determined that the spurious trip of the Channel 4 OTΔT bistable was caused by a momentary signal increase of 400 millisecond duration. During the inspection, the engineers were unable to replicate this signal. They suspected that this condition might be caused by a momentary grounding of dc Bus 24. Technicians installed an oscillographic recorder to continuously monitor eight signal points in Channel 4 OTΔT instrument loop, and placed the OTΔT bistable in the untripped condition for better monitoring.

4.1.2 Station Auxiliary Transformer

Following the generator trip, loads normally powered by the generator were transferred to the station auxiliary transformer (SAT), powered from the 138 kilovolt (kV) transmission system (offsite power). Upon transfer of the auxiliary loads, voltage at the secondary terminals of the SAT dropped due to the increased losses through the transformer from a combination of the load inrush, the increased running loads, and a momentary drop in the transmission system voltage (due to IP2 being removed from the grid). This was a normal response to a plant trip.

Load Tap Changer

During the event, the SAT load tap changer (LTC) was in the "Manual" position and could not respond to the decreasing voltage following the trip. This led to an extended voltage drop on the 480 V buses, which caused the degraded voltage relays to actuate, de-energizing the buses from the offsite power source.

The IP2 SAT is equipped with an automatic LTC which was designed to adjust the voltage ratio of the transformer to maintain a constant voltage on the secondary (low voltage) side. The LTC has 16 taps above and 16 taps below the neutral tap. Each tap change resulted in a change of approximately 2 volts at the 480 V system. The LTC also had an initial time delay to permit the LTC to ride through self-correcting transients such as fault clearing. The IP2 operating procedures gave the operator the option to place the LTC in "Manual" as desired, apparently to increase voltage prior to starting a large 6.9 kV motor load.

The station staff, during interviews, stated that during normal plant operation with the LTC in "Manual," the setting was usually in the lower tap 5 (L5) position. The team estimated that the effect of this position would result in the voltage being lowered about 2% below the neutral position. If the LTC had been left in "Automatic," the potential increase from L5 to R16 (upper tap) could have increased voltage approximately 9.5% following the event. This would have returned the bus voltage to normal, thereby eliminating the loss-of-offsite power.

The required position of the LTC was captured in design and licensing basis documents. On September 29, 1992, the licensee submitted a technical specifications (TS) change request to revise the degraded grid voltage dropout setting for the 480 V buses from 403 V to 421 V. One of the bases for supporting the TS change was to increase the response speed of the SAT LTC by lowering the LTC time delay from 45 seconds to 2 seconds. The licensee also submitted a calculation (EGP-00110-00) entitled "Summary of Degraded Voltage Study," dated January 22, 1993, to justify the TS change. To satisfy this basis, the LTC must be in the "Auto" mode. The TS change request was approved by the NRC on September 22, 1993, and the above basis was described in the safety evaluation report (SER) and in ConEd Calculation EGP-00110-00. The setpoint change was implemented on February 6, 1995, using Modification EGP-92-07762-E.

Operators initiated a condition report (CR) in September 1998, because the LTC was not functioning properly (could not maintain the secondary voltage at 7.1 kV while in "Auto"). This CR indicated that the LTC remained in "Manual." Reviews by operators, the daily management review group, and work management personnel did not identify the need for a safety evaluation or an operability determination for the 480 V buses. In addition, the repair of the LTC material problem was slow. The repair was delayed due to unavailability of parts, and when the parts became available, the repair was again delayed due to scheduling issues. The LTC voltage sensing relay was replaced with a new model during the inspection and the control switch was returned to "Auto."

The team found that operators had a number of inconsistent procedures regarding the operation of the LTC. Some procedures directed that it be left in "Manual" and others made the position optional. These procedure differences were indicative of the technical support staff's failure to properly and consistently translate design and licensing basis information related to the LTC position into procedures.

Although the LTC was repaired and placed in the "Auto" position during the period of this inspection, the team identified no condition report or equivalent that tracked the revisions of the affected procedures. Engineering personnel stated that the plans for procedure revisions would be added to the applicable condition report.

4.1.3 Degraded Voltage Relays

Degraded voltage protection was provided at IP2 by solid-state undervoltage relays on each of the four 480 V vital buses. The degraded voltage relays monitor the voltage on the buses to ensure that sufficient voltage is available to operate safety-related equipment. The degraded voltage setting had been modified in 1995 to raise the voltage dropout setpoint as discussed in Section 4.1.2.

The licensee completed a calculation (FEX-00119-00) entitled "480 Volt Bus Blackout Analysis During the August 31, 1999, Incident" on September 9, 1999. The calculation results and the degraded voltage relay as-found reset values obtained on September 16, 1999, indicated that during the August 31, 1999, event, the degraded voltage relays would have dropped-out and would not have reset, and that the LTC being in the "Manual" mode had caused the de-energization of the vital buses from the offsite power source.

The team found that the calibration procedure for the degraded voltage relays did not include calibration of the reset value. Specifically, the team reviewed Station Procedure PT-R61, "480 Volt Breaker Undervoltage Relays," Revision 24, which covered calibration of the degraded voltage relays and noted that the procedure failed to include the calibration of the degraded voltage relay reset value. The team also reviewed the June 1997 calibration results (most recent calibration prior to the event) and found no calibration records of the degraded voltage relay reset value. The licensee initiated corrective actions to define the reset values, update the calibration procedure, and evaluate the extent of condition.

The team concluded that the failure to incorporate the degraded voltage relay reset value in calibration procedures was an example of poor configuration control. This issue did not directly contribute to the event; however, it was important because incorrectly high reset values could lead to an unsuccessful transfer of 480 V loads to the offsite power source.

The team also noted that engineering personnel were slow in investigating a potential contributor to this issue. During a walkdown of the 480 V switchgear room on September 8, 1999, the team found the pickup tap selected for both of the Bus 5A degraded voltage relays was the "120" tap and that both of the Bus 6A relays were at the "110" tap. With the Bus 5A relays in the "120" tap, the range of calibration could have allowed the relays to reset as high as 504 V, which could result in an unnecessary transfer of the buses to the EDGs. The team brought this to the attention of licensee engineers and on September 8, 1999, they issued Condition Report 199906815 to track the resolution of this issue.

4.1.4 Vital 480 Volt Bus 6A

Overcurrent Trip of 23 EDG

Approximately 14 seconds after bus 6A was energized from the 23 EDG, circuit breaker EDG3, which connects 23 EDG to bus 6A, tripped open. The 480 V circuit breakers utilize solid state overcurrent protective devices known as Amptectors. These overcurrent relays provide a direct trip to their associated circuit breaker. ConEd did not know at the time of the event if the trip came from an overload condition or a bus fault.

Emergency Diesel Generator Loading

The degraded voltage condition, coupled with the plant trip, initiated a load shed of the vital buses and loading of the emergency diesel generators (EDGs). The 21 EDG and 22 EDG successfully energized and loaded their buses as designed. However, EDG 23 was disconnected from bus 6A when its output breaker experienced a short-time overcurrent trip during loading.

The original ConEd design used electro-pneumatic timing relays to control the sequencing of the loads onto the EDGs. Timing relays for the safety injection loading of the diesels were changed to electronic timers in 1997 because of setpoint drift problems with electro-pneumatic timing relays (Modification FPX-91-06757-F, Safeguards Agastat Timers Replacement). This modification also revised the timing for the No. 23 service water pump (SW) from 20 to 15 seconds.

The team noted a deficiency with the revised sequencer timing, in that multiple loads could be sequenced on the 23 EDG simultaneously or within a short period of time. The loss-of-offsite power, or blackout loading, sequences a component cooling water (CCW) pump, an auxiliary feedwater (AFW) pump, and a SW pump onto bus 6A between 11 and 15 seconds following a loss-of-offsite power. Loading three motors within 4 seconds is not found on any of the other EDGs for the blackout loading sequence, the condition is not found on any of the EDGs for the safety injection (SI) loading sequence. The timing relays for sequencing the CCW (11 seconds) and the SW (15 seconds) pumps used electronic timing relays with a tolerance specified in test procedure PT-R13, Safety Injection System [EDG Loading] as ± 2 seconds. The AFW pump was designed to sequence on at 12 seconds using an electro-pneumatic timing relay. The blackout timer for the AFW pump circuit had not been included in the previously discussed safeguards timer replacement modification. With these relay tolerances, it could be possible to sequence all three pumps onto the 23 bus at one time.

The team observed that the ConEd plant computer does not record the operation of the circuit breakers on the 480 V vital bus, so there was no definite indication of how many of the three pumps started or in what time sequence. The IP2 post-trip review included a calculation that showed that the starting current of the AFW pump and the CCW or SW pumps would have been sufficient to trip the EDG circuit breaker.

Prior to the event, the licensee supplemented the calculation of the steady-state loading of the EDG with a safety injection (SI) dynamic loading model. However, the licensee did not have a model using the blackout loading sequence, which had the potential to load three pumps simultaneously. In accordance with the IP2 technical specifications, the EDG loading surveillance test (PT-R13) also uses the SI sequence loading. Following the event, the licensee modified the blackout loading sequence to load on the AFW pump later, thereby removing the potential to load pumps simultaneously.

Amptector Response

The team determined that an inadequate testing methodology for the EDG output breaker Amptector overcurrent relays led to incorrect trip settings. In 1997, IP2 revised the short-time overcurrent trip setpoint for the EDG output breakers from 7500 Amps to 6000 Amps as an add-on to modification FEX 96-11715-E, EDG-[Relay] CVX Trip Removal. The change in the setpoint was to protect the EDG from feeding a fault on the 480 V bus. The licensee calibrated the Amptector overcurrent relays using a secondary current test method. The licensee's initial check of the 52/EDG3 circuit breaker following the August 31 reactor trip indicated that the device was tripping at 6000 Amps as designed. Subsequent checking by the licensee using a primary current injection test method, used by other utilities, revealed that the circuit breaker was tripping in the range of 3000 Amps. The team determined that the secondary injection test methodology was inadequate in that allowed the breakers to trip below the desired setpoint tolerance band.

As part of the corrective actions for this issue, engineers planned to retest all the 480 V breakers that have a short-time overcurrent trip in the 10 Amp secondary current range. The circuit breakers in that class were identified as the EDG breakers (model DB 75), the pressurizer heater breakers (DB 50) and the MCC 21 & 27 feeder breakers (also DB 50s). IP2 selected this sample for testing because of a belief that the setting of the trip using the coarse adjustments of the high range secondary current tester (0-60 Amps) required in this range may not have been sufficiently precise. Other breaker settings were either less than the 8 Amp range, where the low range secondary current tester would be used, or in the 15-35 Amp range of the high range tester where the percent error would not be as significant. The initial test results with the four EDG and two spare breakers indicated that five of the six had settings below the desired 6000 Amps. The results ranged from 2926 to 5928 Amps. Again, these results were due to an inadequate test methodology that did not prevent the breakers from tripping below the setpoint tolerance band.

The team determined that the licensee missed a potential, earlier opportunity to identify the test methodology problem. After the team completed its onsite inspection activities, the licensee's post-trip review team identified that station personnel had failed to complete certain corrective actions for previous breaker problems as documented in a 1997 root cause analysis. These actions, which were due for completion in December 1998, included training personnel and establishing procedures for the primary current injection test method for Amptectors in DB 50 and DB 75 breakers. The licensee stated that the planned corrective actions probably would not have led to the identification of the EDG breaker problem, because the intent of these actions was to exercise the Amptector circuit, not to check the Amptector calibration. A broader corrective action to include checks of Amptector calibration could have presented an opportunity to identify the EDG breaker problem.

Blackout Signal

When the 23 EDG circuit breaker tripped on overcurrent, the resultant loss of voltage coincident with the existing plant trip signal locked out all supplies to bus 6A. A loss of voltage on either bus 5A or 6A is a blackout signal at IP2 and provides a trip signal to the normal supply breakers for all vital buses. In this case, the loss of voltage condition on bus 6A was maintained by the loss of power. This prevented the restoration of the offsite power to the remaining three vital buses.

4.1.5 Loss of DC Bus 24

The operators allowed Battery 24 to continue to discharge after the 24 Instrument Bus de-energized with the loss of the static inverter, despite having declared the battery inoperable. Although the licensee initially had a rationale to allow the battery to discharge to power essential loads (118 V ac Instrument Bus 24 for annunciators and auxiliary feed water control), the team questioned the benefit of continuing to drain the battery after Static Inverter 24 tripped off on low supply voltage (approximately 105 volts) and the 24 Instrument Bus de-energized, which occurred at 9:55 p.m. The battery was allowed to continue to discharge to the point that bank voltage dropped below 57 vdc, when cell reversal was suspected to have occurred. The battery continued to discharge and the lowest recorded voltage for the bank of 58 cells was 35.13 vdc. The battery was taken off line by opening the output breaker when power was restored to dc Bus 24 and the 24 battery charger at 1:11 a.m. on September 1, after having energized Bus 6A from EDG 23. The battery was secured at this time, based on recommendations from the system engineer.

Battery Discharge

The 24 battery at IP2 consisted of 58 cells which had an eight-hour discharge rating of 462 Amp-hours to 1.81 volts per cell. The FSAR indicates that the batteries must maintain the safety-related loads for two hours.

When power to bus 6A and the 24 battery charger was lost, the 24 battery began a discharge that lasted over 11 hours. The battery terminal voltage was manually monitored by technicians during the event at approximately one-hour intervals starting at 5:30 p.m. on August 31, 1999, and increasing to 30 minute intervals by 8:15 p.m.

The team noted that operators and engineers did not take actions to measure the battery individual cell voltages (ICVs) during the discharge. This practice could have provided operators with more complete information on the battery status.

When the battery voltage dropped to about 105 volts, approximately seven and one half hours into the discharge, the inverter supplying the 24 instrument bus tripped off on low voltage, as designed. The battery was allowed to continue to discharge to about until terminal voltage was about 35 volts.

IEEE 450-1995, Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications, cautions that cell reversal may be imminent when an individual cell voltage drops below 1.0 volts. When overall voltage was below 90 volts, one or more cells may have approached 1.0 volts. The first individual cell voltage readings were made a day after the discharge when the battery was placed back on slow charge. Technicians did not check ICVs while the battery was isolated. Therefore station personnel missed an earlier opportunity to detect cell damage. After 10 days, cell No. 2 failed to respond adequately and was replaced.

4.1.6 Other Equipment Issues

Auxiliary Feedwater (AFW) System

The AFW system operated satisfactorily until loss of the 118V instrument bus 24, at which time the AFW flow control valve to steam generator (SG) 24 (FCV-405D) lost power and failed to the fully open position per design. In response, the operators secured the 22 AFW pump. Water levels in SGs 23 and 24 were subsequently maintained by starting and stopping the TDAFW pump (on two additional occasions) to provide batch additions of feedwater to the SGs in lieu of running the pump continuously taking local, manual control of the flow control valve.

Operators imposed an additional challenge on the system by starting and stopping the turbine-driven AFW pump. This added challenge risked further degradation of the AFW system, because the pump was more likely to fail during a starting/stopping evolution than while running, based on failure rate data in the IP2 Individual Plant Examination.

Power Operated Relief Valves

ConEd operates the plant with the pressurizer power-operated relief valve (PORV) isolation (block) valves in the closed position. One of the isolation valves was powered from the 6A 480 V bus and could not have been opened remotely from the control room if needed for plant cooldown. Local, manual operation was still possible.

Emergency Operating Procedure (EOP) FR-H-1 "Loss of Secondary Heat Sink" requires that both PORVs be open to perform feed and bleed operation (a method for cool down if the secondary heat sink is lost). The procedure also directs the operator to open the reactor head vents if one of the PORVs cannot be opened. Both head vents valves need to be open to provide a vent path. One of the head vent valves was powered from the 6A 480 V bus and could not have been opened remotely from the control room.

4.2 Organizational Response

The team findings for this area were obtained from an independent determination of the August 31 trip event sequence and causal factors, and an evaluation of the ConEd response to the event as determined by interviews with individuals who played a key role in the event response. The plan to troubleshoot and recover electrical power was not formalized during the event, but was described to the AIT on September 5, 1999.

Management focus on understanding and limiting future risk

The team identified that management actions during and following the event were weak. Although the senior managers had verified that the plant trip left the reactor safely shutdown with stable primary plant conditions, they failed to become fully engaged in the station's response and by their own admission, did not fully recognize the plant vulnerabilities caused by the partial loss of power. They failed to assure the plant staff responded to assist the operators in mitigating the degraded plant conditions as quickly as possible. Actions were focused on plant operations, plant risk, and degrading equipment conditions. The bases for the team findings are described below.

Senior management did not firmly establish and communicate the expectation that recovery from the degraded plant condition was of the highest priority and took precedence over preparations for shutdown work activities. Failure to do so allowed valuable station resources and the staff's focus to be improperly diverted from recovery of the degraded plant conditions to outage planning activities at a 4:00 p.m. plant meeting that discussed shutdown work plans and schedules; and a 4:30 p.m. Station Nuclear Safety Committee meeting that reviewed outage test procedures. These activities, identified by key members of the plant staff as improper and as significant distractions from their duties to support the post-trip recovery efforts to mitigate the loss of electrical power, occurred at a time when the plant conditions were degrading.

The day shift Watch Engineer calculated the Daily Risk Factor (DRF) using Operations Administrative Directive (OAD) 37 in preparation for the shift turnover activities with the oncoming crew at 7:00 p.m. and due to the changing plant conditions. The DRF is a ConEd measure of risk that is used as an aid to the operators. The DRF was calculated to be 196 due to Bus 6A being inoperable, which is a Risk Condition "Red." The Watch Engineer indicated this was the first time IP2 was in a "Red" condition and the typical DRF is less than 1.0. The Watch Engineer informed the Shift Manager of the risk assessment results and made an entry in the shift log. The oncoming night shift Watch Engineer also confirmed the risk condition using the on-line risk monitor, and calculated a preliminary core damage frequency of 5.16×10^{-3} due to the inoperable Bus 6A. This result was communicated to the Shift Manager and discussed with the shift crew during the turnover, with emphasis placed on the need to avoid removing any other plant equipment from service. The team determined that the risk information was not communicated outside of the control room to all levels of senior management, nor was the information utilized by the plant staff to evaluate plant conditions or expedite recovery actions and equipment repairs to reduce the plant vulnerability.

As discussed earlier (see section 4.1.2), the operators allowed Battery 24 to continue to discharge after the 24 Instrument Bus de-energized with the loss of the static inverter, although they had declared the battery inoperable. While the licensee initially had a rationale to allow the battery to discharge to continue to power essential loads, there was no apparent benefit after the 24 instrument bus was de-energized. The battery was finally secured after power was restored to the 24 instrument bus, based on recommendations from the system engineer.

Equipment restoration plans and contingency planning

The Operations Manager evaluated plant status and information about the trip, and identified the work priorities to support the operators. The causes for the undervoltage condition on the 480 V buses, and tripping of the EDG 23 breaker were not known. Based on the undervoltage indications in the control room and the overcurrent indications on the breaker in the switchgear room, the operations manager suspected a fault condition on either Bus 6A or MCC27A. The Operations Manager developed a recovery plan/decision tree to recover electrical power following the plant trip. The plan, which was not written or formalized and was developed over several hours, started with taking insulation resistance (IR) measurements on Bus 6A, and continued with actions by maintenance to take IR measurements of 6A attached loads if Bus 6A was not faulted; and with actions by engineering to develop temporary facility changes (TFCs) for alternate power supplies if either Bus 6A or MCC 27A was faulted.

The Operations Manager met with maintenance and engineering periodically to discuss the plan as it developed. The first priority was given to take IR measurements of Bus 6A to determine whether it could be returned to service. Based on the event sequence and plant status, the licensee recognized that offsite power could not be restored to the 480 V buses due to interlocks from the undervoltage condition. With Bus 6A de-energized, the undervoltage interlocks prevented the reset of the blackout logic and closing the supply breakers from the 6.9 KV buses. The licensee recognized the need to defeat the blackout logic using a TFC to allow powering buses 5A, 3A, and 2A from offsite power. The licensee also recognized the need to generate TFCs if 6A could not be restored to service, and to provide alternate power to the 24 battery charger assuming MCC 27A could not be returned to service.

A third TFC was added to the engineering work on the evening of August 31 which was to develop an alternate source of power to the waste gas compressors which would be needed for the plant cool down. The licensee's post-event review concluded that the cooldown could have been completed without the compressors.

Support by the engineering and maintenance organizations

The maintenance and engineering organizations supported the operators in the review, evaluation, investigation and repair of degraded equipment conditions following the reactor trip and loss of power, and provided support in response to specific requests to: investigate a suspected fault condition on Bus 6A and MCC 27A, and provide temporary facility changes to supply an alternate source of power. Starting from 4:00 p.m., maintenance and engineering personnel worked their respective tasks. Six engineers were directly involved in work to reduce plant risk by troubleshooting and restoring Bus 6A and provide alternate power to the battery charger. An additional seven engineers were assigned to other tasks not directly related to reducing the time in a vulnerable condition (the tasks included trip response, licensing support, troubleshooting protection channel #4, alternate power for the waste gas compressors, supporting a containment entry, and repairing the low pressure steam dump valves).

The technical support was not timely to minimize the time in a degraded plant condition with high risk significance. The response organization took ten hours to tag and take IR measurements of the 6A bus and associated electrical components. Similarly, after eight hours engineering was still developing the TFCs and associated safety evaluations to defeat the Bus 6A under voltage interlocks that would allow powering Buses 2A, 3A and 5A from the offsite supply, and to provide alternate power to the 24 battery charger. Engineering considered a previously developed TFC for bypassing the blackout signal, but developed a simpler method to defeat the interlock (pull control fuses versus removing a relay). Engineering recognized that an electrical separation issue would result if the battery charger TFC was implemented. Engineering was tasked to develop a TFC for the waste gas compressors. Engineering was still working on all three TFCs at midnight after maintenance had finished the electrical checks that showed Bus 6A and MCC 27A could be returned to service. The TFC for the Bus 6A interlocks was written but had not been approved for use. None of the TFCs were used to restore power to Bus 6A or MCC 27A. Neither the electrical checks on the buses nor the TFCs for providing alternate power were completed prior to the loss of Battery 24 and the annunciators.

The team noted other examples where adequate technical support was not provided to the operators in a timely manner. This was evident in the lack of : (i) a thorough review of Technical Specification LCOs and Emergency Plan EALs; (ii) a thorough review of equipment lost due to the loss of Bus 6A; (iii) contingency plans for the degrading 24 battery and the potential loss of the 24 dc bus; and, (iv) anticipation of the impact on auxiliary feed water control on the loss of the 118 V ac instrument bus. As a result, ConEd erred in determining the most limiting technical specification regarding the time requirement to initiate a plant cooldown below 350° F; ConEd did not declare an Unusual Event for the Loss of All AC power to the vital buses; and, the decision to cycle the turbine-driven auxiliary feed water (TDAFW) pump to control steam generator levels created unnecessary challenges to the AFW system, and was not sensitive to the high risk significance of the system. Also lacking in the technical support to operations was any significant contingency planning through the asking of "what if" questions on how plant conditions might be impacted by the degrading power conditions, or how the plant might continue to degrade.

The team concluded that the command and control of the post trip organization response was not fully effective as evident in poor use, coordination and prioritization of engineering, maintenance and operations tagging resources. Although an adequate type and number of resources were available, those resources were not fully utilized to assist the operators or minimize the time in a plant high risk condition.

The team concluded that the response organization did not provide timely support to operations in the review of plant conditions relative to the emergency plan nor in its execution. Further, once an Unusual Event was declared, although federal requirements for offsite notification were met, the expectations of the State and Local agencies were not. Notification procedures, in some instances, were found to be inconsistent and lacked clarity. Additionally, implementation of the procedures was not fully completed as per training.

4.3 Operator Response

The team determined that overall operator response to the event was mixed. While control room operators' use of emergency operating procedures (EOPs) was good, operators were challenged in several other areas. Operators maintained good control of primary plant parameters at all times. Challenges occurred primarily due to procedure deficiencies, logging problems, communications, and poor support by personnel outside the control room.

- Control room operators performed well while using EOPs. They stepped through the procedures in a rigorous manner with clear and concise communications. Operators took appropriate steps to check control rod position indications when one rod (K-2) was observed to be not fully inserted. However, they were challenged by the unavailability of a voltmeter designated for use with EOPs for checking rod positions. The voltmeter was specified to be in the control room, but administrative controls did not prevent it from being removed.

- The team identified that operations shift management did not declare an Unusual Event after offsite power was unavailable to the 480 V vital buses for over 15 minutes. This missed declaration occurred primarily because of an incomplete emergency action level (EAL) description in the Emergency Plan procedure. The EAL table only specified an Unusual Event declaration if all three sources of offsite power are not available for greater than 15 minutes. The table did not indicate that the basis of the EAL applies, more specifically, to unavailability of power to the 480 V vital buses. This information was in the EAL technical bases document which is kept in the control room, but was not reviewed by shift management. This condition existed at approximately 2:50 p.m. on August 31, 1999. On September 13, 1999, station personnel reported the missed declaration to the NRC.

- Operators imposed an additional challenge on the AFW system by starting and stopping the turbine-driven AFW pump for level control of steam generators 23 and 24, following the loss of power to the flow control valve to steam generator 24. Operators stated that they did not direct a nuclear plant operator (NPO) to take local, manual control of the flow control valve because the NPO would be unavailable for other duties. Starting and stopping the turbine-driven pump risked further degradation of the AFW system, because failures of the turbine-driven pump are more likely during the starting evolution than while the pump is running.

- The licensee's Utility Assistance Team identified that operators failed to enter technical specification (TS) 3.3.F.1.b, which required the initiation of plant cooldown to less than 350° F within 12 hours. Since operators commenced plant cooldown outside of this 12-hour period, the plant was in violation of technical specifications. The plant reported this condition to the NRC on September 4, 1999.

- The team determined that operators' documentation of TS limiting conditions for operation (LCOs) was less than rigorous, which likely contributed to the missed TS entry. Specifically, in a log entry for crew turnover following the event, operators only logged that they had entered "multiple LCOs and TS 3.0.1 combinations with bus 6A out of service," rather than listing the applicable LCOs. Operators also did not log the notifications to the NRC during the event.

- The team noted during interviews of operations personnel that unclear communications between shift management and operations support personnel caused the initiation of a tagout for the 6A bus to be delayed by approximately 30 minutes.

- After exiting emergency operating procedures, operators identified that no procedure directly addressed the loss of a single 480 V vital bus. Operators referred to Abnormal Operating Instruction (AOI) 27.1.1, "Loss of Normal Station Power," and System Operating Procedure (SOP) 27.1.15, "Removing 480 Volt Buses From Service," for limited guidance. Neither procedure was directly applicable for responding to the loss of the 6A bus, which operators suspected was due to a fault on the bus.

- Nuclear plant operators (NPOs) assigned to monitor the emergency diesel generators did not take hourly log readings as specified in SOP 27.3.1, "Emergency Diesel Generator Manual Operation." The NPOs were directed by the control room supervisor to monitor the EDGs, per AOI 27.1.1, "Loss of Normal Station Power," but the NPOs did not take the logs as expected by operations supervision. The team noted that the NPOs were knowledgeable of the EDGs and support systems, and the failure to take logs did not have an impact on the event. An NPO had remained in the EDG building and would have been available to react to any local alarms and any other abnormal conditons.

- There were no formal briefings conducted to discuss actions to prevent or cope with the loss of 24 Instrument Bus and 24 Battery. Consequently, operators were not fully focused on the higher priority actions, roles, and responsibilities for the loss of this equipment.

- The team determined that operators had poor procedures and training for responding to a battery with degraded voltage or a fully loaded battery about to lose effectiveness due to low voltage. Consequently operators did not open the battery breaker to limit further degradation of the 24 battery. Also, operators did not request monitoring of individual cell voltages. Operators finally opened the breaker when the 24 dc bus was re-energized.

4.4 Interim Corrective Actions for the Event

The team concluded that station management implemented adequate interim corrective actions to review and address both equipment and personnel performance in response to the reactor trip event. Station management directed two teams, a post-trip review team and a Utility Assistance Team, to review the event. Management also developed a Recovery Plan to address the problems identified during the reviews.

The post-trip review team's activities were adequate. The post-trip review team established the time line and sequence of events for the reactor trip and recovery actions in accordance with the licensee's post-trip review and evaluation procedure, OAD 23. The team was also tasked with developing the root causes and determining corrective actions to prevent recurrence. One area of note in the assessment of post-trip data is the lack of computer information on the starting and stopping of pumps and other loads on the 480 V buses. The lack of this information hampered the ConEd review of the loads on Bus 6A when the EDG 23 supply breaker tripped on overcurrent.

On September 1, 1999, senior plant management recognized that there were weaknesses on how the organization responded to the plant trip. ConEd formed a Utility Assistance Team (UAT) to independently assess the performance in plant equipment and personnel, and to report to ConEd management observations and recommendations. The staffing for the UAT was expanded to include industry representatives.

The AIT determined the UAT reviews were thorough in evaluating the organizational response and identifying weaknesses. The UAT provided observations and recommendations to ConEd management on September 6, 1999, which included findings that: management exhibited a single-minded focus on Bus 6A tagout, and did not fully mobilize and lead the plant staff in evaluating the transient progress effectively; event mitigation and system restoration plans were not formalized or documented; management expectations for conservative operations appeared weak following the trip; senior management relied on middle level managers for evaluation and oversight of the plant; some knowledge deficiencies existed in the areas of the dc electrical system, boration options without waste gas compressors, and senior management's familiarity with technical specifications, emergency plan and safety systems; and, deficiencies in keeping the entire plant response team updated on plant status.

In response to the UAT findings, ConEd developed actions plans to address organizational performance in five broad areas: processes, event response, communications, command and control, and training. ConEd also formed an Event Response Team led by senior level managers that would be used to augment plant staff to assure adequate support to the operators.

During a meeting with the NRC on September 14, 1999, in the NRC Region I Offices, ConEd presented a Recovery Plan, Revision 0, which addressed the management, human performance, process and equipment problems highlighted by the August 31 plant trip, and which provided the structure and guidance to the organization for those issues. The Plan also includes extent of condition assessments to determine if similar problems exist in other areas. NRC evaluation of the Recovery Plan continued after this inspection.

5.0 CONCLUSIONS

As discussed in Section 3 of this report, the team concluded that the event revealed problems in four broad areas: Configuration Control; Management Oversight; Corrective Actions; and Technical Support. The team's conclusions in these areas are summarized below.

5.1 Configuration Control

The team concluded that weaknesses in the control of plant configuration was a primary cause of this event. The configuration control problems resulted in the plant operating differently than assumed in the licensing and design bases and complicated the recovery actions. The team noted four configuration control issues in which station personnel did not ensure that the plant was maintained consistent with the licensing and design bases:

- The station auxiliary transformer load tap changer was not maintained in the automatic position as required by the licensing bases.
- The 23 EDG output breaker overcurrent setpoint was not properly controlled due to an inadequate test methodology.
- The 23 EDG load sequencing allowed, within relay tolerances, multiple pump motors to load onto the bus at one time.
- The degraded voltage relay reset values for the 480 V buses were not controlled.

5.2 Management Oversight

The team concluded that management oversight and response to the event were weak in several respects. Management actions during and following the event were not focused on understanding and limiting future risk. Station managers did not fully appreciate the plant vulnerabilities caused by the partial loss of power. Thus, they did not establish expectations that recovery from the degraded plant conditions was a priority over preparations for shutdown work activities, and they did not ensure the plant staff responded to assist the operators to mitigate the degraded plant conditions as quickly as possible. Equipment restoration plans and contingency planning were not clearly understood or fully developed.

5.3 Corrective Actions

The team concluded that some instances of poor or ineffective use of the corrective action process contributed to the events leading to the plant trip with complications. The team also noted other corrective action implementation weaknesses during the station's event response.

- Engineering personnel did not investigate the cause of an OTΔT signal increase on August 26, 1999.
- Station personnel failed to recognize and evaluate a potential trend in reactor protection system (RPS) problems and failures.
- Station personnel missed a potential, earlier opportunity to identify the Amptector test methodology problem. Corrective actions for previous breaker problems, which addressed test methodology, were overdue and incomplete.
- Station personnel did not evaluate the station auxiliary transformer load tap changer condition report for safety and operability impact.
- The team identified no corrective action document or other means which tracked the revision of all procedures that impacted the position of the station auxiliary transformer load tap changer.
- Engineering personnel were slow in investigating degraded voltage relay reset settings as a potential contributor to the event.

5.4 Technical Support

The team concluded that technical support to operations during the event was untimely and weak. This was evident in the lack of a timely and thorough review of technical specification LCOs and the Emergency Plan EALs; the lack of viable contingency planning for the degrading No. 24 battery; and the failure to anticipate the loss of the 118 V ac instrument bus and plan for the impact on auxiliary feed water control. Also lacking was any significant contingency planning on how plant conditions might continue to degrade.

The event revealed examples of poor technical support to operations that preceded the reactor trip. These examples included: several procedure adequacy problems, less than adequate communication of the licensing and design bases for the load tap changer, and lack of thorough investigation of prior anomalies observed in the reactor protection instrumentation. Additionally, engineers did not provide adequate controls for the degraded voltage bus relays reset point, the sequencer timing for the vital bus loading on a blackout signal, and calibration of the circuit breaker Amptectors.

PARTIAL LIST OF PERSONS CONTACTED

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W. Smith, Shift Manager, Operations
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LIST OF ACRONYMS USED

AC	Alternating Current
AIT	Augmented Inspection Team
AFW	Auxiliary Feedwater
Amp	Ampere
AOI	Abnormal Operating Instruction
ARP	Alarm Response Procedure
CAG	Corrective Action Group
CCR	Central Control Room
CCW	Component Cooling Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
ConEd	Consolidated Edison
CR	Condition Report
DC	Direct Current
DRF	Daily Risk Factor
EAL	Emergency Action Level
EDG	Emergency Diesel Generator

EN	Event Notification
EOP	Emergency Operating Procedure
FCV	Flow Control Valve
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
I&C	Instrumentation and Control
IP2	Indian Point Unit 2
IR	Insulation Resistance
KV	Kilovolt
LCO	Limiting Condition for Operations
LTC	Load Tap Changer
MDAFW	Motor-Driven AFW
MCC	Motor Control Center
NPO	Nuclear Plant Operator
NRC	Nuclear Regulatory Commission
NUMARC	Nuclear Utility Management and Resource Council
OAD	Operations Administrative Directive
OTΔT	Over Temperature Delta Temperature
PM	Plant Manager
PORV	Pressure Operated Relief Valve
RPS	Reactor Protection System
RO	Reactor Operator
SAT	Station Auxiliary Transformer
SE	Safety Evaluation
SER	Safety Evaluation Report
SG	Steam Generator
SI	Safety Injection
SNSC	Station Nuclear Safety Committee
SOP	Station Operating Procedure
SRO	Senior Reactor Operator
SW	Service Water
TDAFW	Turbine-Driven AFW
TFC	Temporary Facility Change
TPC	Temporary Procedure Change
TS	Technical Specification
UAT	Utility Assistance Team
VP	Vice President, Nuclear Power
WG	Waste Gas

Enclosure 2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

September 3, 1999

MEMORANDUM TO: Wayne Lanning, Director, Division of Reactor Safety
A. Randolph Blough, Director, Division of Reactor Projects

FROM: Hubert J. Miller
Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM (AIT) CHARTER - INDIAN POINT 2 REACTOR SCRAM WITH COMPLICATIONS

You are directed to perform an Augmented Inspection Team (AIT) to review the causes, safety implications, and associated licensee actions as a result of a reactor scram with complications at Indian Point 2 on August 31, 1999. The basis of the NRC concern is that the event was complicated by significant unexpected system interactions, which involved safety-related equipment. Specifically of concern are: the adequacy of vital bus power restoration efforts, which led to the complication of a loss of instrument power, and the adequacy of the licensee's response to the events. The inspection shall be conducted in accordance with NRC Management Directive 8.3, Part III, Augmented Inspection Team and the guidance provided in Inspection Procedure 93800, and Regional Instruction 1010.1. This memorandum and the attached inspection plan provide additional specific instructions, which details the scope of the inspection.

DRS is assigned responsibility for the overall conduct of this inspection. DRP is assigned responsibility for resident inspector and clerical support and coordination with other NRC offices. Mr. William Ruland is the Team Manager for this inspection. Mr. Jimi Yerokum is designated as the onsite Team Leader. Team composition is described at the end of this memorandum. Team members will work for Jimi Yerokum and are assigned to this task until the report is completed. Evaluation of risk assessments will be performed by the regional office. DRS is responsible for the timely issuance of the inspection report and identification of any potential generic issues. DRS, in coordination with DRP, is responsible for the identification of followup of issues raised during the AIT, including possible enforcement actions.

The inspection began on September 2, 1999. In accordance with MD 8.3 the inspection report must be transmitted to the Region I Administrator by October 2, unless relief is appropriately granted.

Attachment: Augmented Inspection Team (AIT) Charter and Membership

ATTACHMENT- AUGMENTED INSPECTION TEAM (AIT) CHARTER AND MEMBERSHIP

CONDUCT OF THE INSPECTION

The team should understand the scope and direction of the licensee's investigations and assessment of the events, and their initial responses. Through sampling and independent verification, the team may use facts and information collected by the licensee's investigation teams. The pace and nature of team activities should be gauged to assure, where practicable, that they do not unduly impact the licensee's efforts.

The team leader shall develop an inspection plan, that outlines the areas of responsibility for the team members to ensure the identification and documentation of the relevant facts to support the objective below.

Inspection procedure 93800 provides guidance on the general conduct of an AIT.

OBJECTIVES

Conduct a timely, thorough, and systematic review of the circumstances surrounding the August 31, 1999, reactor scram and unusual event. Use collected information and documentation to complete the following;

a. Compare the actual plant response with the design basis. Focus on design of electrical systems. Identify significant potential design vulnerabilities for further risk evaluation (e.g., loss of instrument or DC busses).

b. Determine the event causal factors including the most probable root causes of the event and document equipment problems, failures, and/or personnel errors which directly or indirectly contributed to the event. Determine the relationship of previous events or precursors, if any, to this event as appropriate.

c. Evaluate any procedure and process issues.

d. Determine whether the licensee actions during and after the event were focused on understanding and limiting future risk. Areas of interest include:
   - Equipment restoration plans and contingency planning if not restorable. Assess the identification of equipment issues and setting of priorities for troubleshooting and repair;
   - Planning for possible emergency declaration activities;
   - The quality of support provided by the licensee's engineering and maintenance organizations.

e. Evaluate operator response to the reactor trip including the use of emergency operating procedures. Evaluate subsequent operator actions for restoring equipment. Evaluate the quality of procedures and controls available to cope with this event.

f. Assess the risk and safety significance of the event related to any problems identified. Provide sufficient information so that the overall risk significance of the event and the subsequent licensee actions may be assessed.

g. Evaluate the timeliness of the classification and declaration of the unusual event and whether emergency plan implementation procedures were followed.

h. Evaluate the adequacy of the post-trip and licensee team technical evaluation and any planned or implemented corrective actions.

TEAM COMPOSITION

The assigned team members are as follows:

Team Manager:	William Ruland, DRS
Onsite Team Leader:	Jimi Yerokum, DRS
Assistant Team Leader:	Leonard Chueng, DRS
Onsite Team Members:	William Raymond, SRI, IP2
	Blake Welling, DRP
	Chris Welch, DRS
	Tom Kenny, DRS
Regional Assistance:	
Risk:	Tom Shedlosky, DRS
Electrical:	George Morris, DRS
Emergency Planning:	Bob Bores, ORA
	Dave Silk, DRS

Enclosure 3

NRC Indian Point Unit Two Augmented Inspection Team Exit Meeting

Inspection Report 50-247/99-08

September 27, 1999

1

Agenda

- Introduction and Background - W. Ruland, Team Manager
- Preliminary Findings - J. Yerokun, Team Leader
- Consolidated Edison Comments - J. Groth, Chief Nuclear Officer, ConEd.
- Concluding Remarks - H. Miller, Regional Administrator, USNRC, Region I

2

Introduction and Background

- Establishment of the Augmented Inspection Team (AIT)
- Purpose of an AIT
- Review of Team Charter, Including Team Membership

3

AIT FINDINGS

Sequence of Events.

Safety Significance.

Personnel Performance.

Root Cause Areas.

4

SEQUENCE OF EVENTS

- Reactor Trip - Aug. 31, 1999, 2:31 P.M.
- 6.9 kv Buses 1, 2, 3, and 4 transfer from unit to station auxiliary transformer.
- Offsite power lost to 480 volt vital buses.
- All three emergency diesel generators start.

5

SEQUENCE OF EVENTS (continued)

- EDG 23 output breaker opens, vital bus 6A without power.
- Battery charger 24 de-energized.
- Battery 24 low voltage - 9:55 P.M.
  - Loss of instrument bus 24 and most control room alarms.
- Declared Unusual Event - 9:55 P.M.

6

SEQUENCE OF EVENTS (continued)

- Emergency power restored to Bus 6A -9/1/99, 12:43 A.M.
- Instrument bus 24 and the control room alarms restored.
- Unusual Event terminated - 3:30 A.M.
- Offsite power restored to vital bus 6A - 9:08P.M.

7

SAFETY SIGNIFICANCE

- Degraded Systems:
  - Auxiliary feedwater system
  - Emergency diesel generator
  - Pressurizer power operated relief valve

8

SAFETY SIGNIFICANCE (continued)

- Loss of bus 6A resulted in loss of power to:
  - Some emergency core cooling equipment.
  - One motor-driven auxiliary feedwater pump.
  - One normally closed PORV block valve.
  - Automatically control one auxiliary feedwater flow control valve.

9

SAFETY SIGNIFICANCE (continued)

- Risk Significance.
  - Risk increased due to the loss of power to redundant equipment.
- Safety Consequences:
  - There were no consequences to public health and safety.

10

PERSONNEL PERFORMANCE

- Operator performance was mixed. They were also challenged in some areas.
  - Accomplished Emergency Operating Procedures well.
  - Cycled the turbine-driven auxiliary feedwater pump.
  - Did not recognize entry into service water technical specification.
  - Slow in getting Bus 6A tagged out.

11

PERSONNEL PERFORMANCE (continued)

- The support provided to operators for recovery was weak in some important respects:
  - Use of of plant risk insights to prioritize and expedite actions was not properly communicated.
  - Weak coordination of temporary facility changes.
  - Slow development of appropriate contingencies for impending equipment losses.
  - Untimely restoration of power supplies.

12

ROOT CAUSE AREAS

- Contributing to the event and complicating the response to it were problems in the following areas:
  - Configuration Control
  - Management Oversight
  - Corrective Actions
  - Technical Support

13

CONFIGURATION CONTROL

- Deficiencies in configuration control:
  - Station auxiliary transformer load tap changer was not maintained in the "AUTO" position.
  - The 23 EDG output breaker over-current trip setting was not properly set.
  - The 480 volt bus degraded voltage relay reset setting was not verified.

14

MANAGEMENT OVERSIGHT

- Management oversight and response to the event were weak in several respects:
  - Focus on shutdown work plans and schedules rather than event response.
  - Weak coordination and use of resources for plant recovery.
- The utility assessment team reviews were thorough in evaluating the organization's response and identifying weaknesses.

15

CORRECTIVE ACTIONS

- Important corrective action problems:
  - Root causes for prior anomalies and deficient conditions associated with the reactor protection system had not been established.
  - Untimely repair of load tap changer malfunction that was identified in September 1998.

16

TECHNICAL SUPPORT

- Weak technical support before and during the event:
  - Prior RPS anomalies were not properly communicated within and across organizational boundaries.
  - Degraded voltage relay setting was not periodically tested.

17

TECHNICAL SUPPORT (continued)

- Weak technical support (continued)
  - Conflicting procedures existed for load tap changer control.
  - Lack of a recovery procedure for the loss of an individual 480 Volt emergency bus.
  - Emergency Preparedness procedure missed Unusual Event declaration.

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ATTACHMENT 1

SEQUENCE OF EVENTS
and
ORGANIZATION RESPONSE TIME LINE

The AIT established a sequence of events for the plant response; those times are shown in **bold face.** The plant support responses are also shown to describe the organization's actions to support the operators. The organization response times were constructed from interviews and should be considered approximate. Information notes are shown in *italics.*

August 31, 1999

Initiating Event: Instrumentation and Controls personnel were performing maintenance on a reactor protection system Channel 3 trip bistable, which required placing the Channel 3 over temperature/delta temperature (OTΔT) bistable in trip. A spurious OTΔT trip occurred on Channel 4, which completed a 2 of 4 OTΔT trip logic, causing an automatic reactor trip.

Time	Event
2:31 p.m.	**Reactor Trip from 99% Power. Operators entered emergency operating procedure E-0, "Reactor Trip or Safety Injection."**
	Approximately 30 seconds later, 6.9 KV Buses 1, 2, 3, and 4 transferred to the Station Auxiliary Transformer (Normal Offsite power line) as designed.
2:32 p.m.	**Operators transitioned from E-0, "Reactor Trip or Safety Injection," to ES-0.1, "Reactor Trip Response."**
2:35 p.m.	**480 V Vital Buses 2A, 3A, 5A, and 6A normal supply breakers from offsite source opened unexpectedly and all three diesels started and began loading to their respective buses.**
	21 Motor-Driven Auxiliary Feedwater Pump (powered by Bus 3A), started. **23 Motor-Driven Auxiliary Feedwater Pump (powered by Bus 6A), started.**
	EDG 23 output breaker (EG3) tripped open due to a short-time overcurrent condition, de-energizing bus 6A.
	Loss of 480 V MCC 27A, which supplies 118 V ac Instrument Bus 24, placing Instrument Bus 24 on Battery 24 through Static Inverter 24.
	Loss of Pumps: MDAFW 23; Charging Pump 23; CCW pump 23; Essential SW pump 26.
2:35 p.m.	**Plant entry into Technical Specification LCO 3.0.1 due to loss of bus 6A (TS 3.7.A.4 could not be met).**

2:35 p.m.	Engineering personnel responded to control room and noted that the trip was caused by over temperature delta temperature (OTΔT); a blackout signal occurred and remained in effect; DG23 breaker had tripped.
2:39 p.m.	**Operators started 22 Charging pump (on Bus 3A) and restored charging to reactor coolant system.**
2:40 p.m.	**Operators placed Turbine-Driven Auxiliary Feedwater (TDAFW) Pump 22 in service.**
2:45 p.m.	(Approximate, based on interview) The shift manager referred to the Emergency Plan emergency action level (EAL) table in the control room and determined that offsite power was still available and entry into an Unusual Event per Section 6.1.1, was not required.
3:22 p.m.	**Operators exited ES-0.1 and transitioned to plant operating procedure (POP) 3.2, "Plant Recovery From Trip."**
3:30 p.m.	Engineering personnel accompanied operators and maintenance personnel to the switchgear room to review the status of the EDG breaker from 3:00 to 3:30 p.m. Noted the MCC 26B breaker was closed, DG breaker Amptector flag up, 6.9KV buses were satisfactory; and, the 480 buses were clear of undervoltage, except for 6A.
4:00 p.m.	The Engineering Supervisor mobilized engineering resources from 3:15 to 4:00 p.m. The supervisor directed day-shift engineers to remain in standby pending assignments to assist operations and scheduled additional engineers with electrical expertise to provide continued support for the back shifts. Other engineering assignments included a review of the cause for the OTΔT spiking and gathering the necessary drawings.
4:00 p.m.	**A Plant Meeting was conducted - Topics included: Discussion of priorities for plant restoration, outage preparations, development of planning packages, and establishment of engineering teams for Temporary Facility Changes.** The meeting was opened led by the work week manager and a discussion focused on the shutdown work list. The Operations Manager ended the meeting with a discussion of plant status and information about the trip, and summarized the work priorities to support the operators. At that time, it was not known why the undervoltage occurred, or why the EDG 23 breaker had tripped. Based on the undervoltage indications in the control room and the overcurrent indications on the breaker in the switchgear room, operators suspected a fault condition on either Bus 6A or MCC27A. The plan was to troubleshoot the electrical equipment and restore power. The priority was the restoration of Bus 6A. The support needed to accomplish the work was discussed.

Immediately following the 4:00 p.m. meeting, the Operations Manager met with engineering to discuss a plan to restore power to Bus 6A. The plan was to take IR readings of Bus 6A to see if it could be returned to service. Based on the event sequence and plant status, the licensee recognized that power to the 480 V buses could not be switched to offsite power due to interlocks from the undervoltage condition. With Bus 6A de-energized, the undervoltage interlocks affected the ability to reset the blackout logic. During interviews, engineers stated that they recognized the need to defeat the blackout logic. The first request to engineering was to develop a temporary facility change (TFC) to remove blackout interlocks to allow powering 5A, 3A, 2A from offsite power with 6A de-energized. Engineers also recognized the need to generate TFCs if 6A could not be restored to service, and the development of a TFC to provide alternate power to the 24 battery charger.

The engineer assigned to do the TFC for the 6A interlocks consulted with licensing regarding the use of a TFC previously used in 1990. This discussion identified the need to revise the safety evaluation. After further review (about 2 hours), engineering identified a better method to defeat the interlock: rather than remove a relay, the fuses to the circuit that fed the undervoltage relays could be pulled, which had the same affect to tell the blackout logic that Bus 6A had voltage. A TFC and SE using this approach was worked through the evening with help from another engineer.

The Bus 6A recovery plan was discussed with Operations, I&C, Maintenance and the System Engineer. The Maintenance Manager met with systems engineers to discuss troubleshooting strategy on Bus 6A - take IR readings of the bus after operations completes the tagout. A check of the DG breaker and Amptector setting was added to the plan. A request to take IR readings of MCC 27A came at 6:00 p.m. from operations and maintenance. Licensing supported the Operations Manager to review TS 3.0.1 requirements and concluded it was acceptable to stay at 350° F when conducting the shutdown under the existing plant conditions.

4:01 p.m. **Operations Watch Engineer made the NRC event notification for the reactor trip (Event Notification (EN) 36104)**

4:30 p.m. **(Time approx.) Station Nuclear Safety Committee conducted a meeting for a shutdown work procedure.**

AIT Note: *Personnel stated that the SNSC meeting, which covered a topic unrelated to the trip and recovery, distracted some plant personnel from efforts to evaluate Bus 6A and recover from the event.*

5:00 p.m. Licensing supported plant engineering on whether it was acceptable to use a previously used TFC/SE for an alternate supply to the battery charger. The previous TFC/SE was not acceptable for the post-trip plant conditions (hot shutdown) since train separation was not preserved, which would be an operability requirement above 350° F. The jumper was previously used in cold shutdown. Engineering proceeded to develop another approach that was consistent with the licensing basis.

5:15 p.m. Maintenance crew was ready to take insulation resistence (IR) readings of the bus and was in standby waiting for the tagout. System engineering supported the plant to expedite the Bus 6A tagout by providing input on the scope of the tagout.

5:30 p.m. The Operations Manager instructed the Shift Manager to have the operators review the abnormal operating instructions for the loss of dc and the instrument bus. The shift manager assigned this task to the Watch Engineer, but it was not completed immediately. The Operations Manager questioned the status of this effort at the shift turnover, and the night crew did the review after 8:00 p.m.

The Operations Manager decided to stay on Battery 24 as long as possible based on the need to (a) preserve the 118 V ac instrument bus because it powered AFW valves needed for SG feed control; and, (b) keep power to the annunciators. The operators reviewed how to reduce load on the instrument bus and noted that the static inverter and associated 118 V ac instrument bus was the largest load. The instrument bus provided control power for annunciator acknowledge and reset (new alarms).

5:30 p.m. (Based on an interview) The Operations Manager's decision tree was developed by this time and he met with the Engineering Supervisor to discuss the plan and priorities (The plan was not formalized or issued to the plant staff, but was described to the AIT on September 5).

5:30 p.m. Engineering established a Temporary Facility Change team for temporary feed to waste gas compressors.

The Operations Manager requested engineering personnel to develop an additional TFC to provide power to the compressors, which were affected by the loss of MCC 27A. The TFC would be needed to support plant cool down if MCC 27A could not be re-energized. The TFC provided a alternate power to the waste gas compressors to process waste gases while borating the primary system during the plant cool down.

6:00 p.m. The plant manager (PM) and the VP Nuclear had left site by this time.

AIT Note: *The PM left the site with the intention of getting rest and coming back to the site to relieve the mid-level managers. The PM received repeated calls about plant status and the Unusual Event during the evening. The PM came back to the plant at 3:00 am September 1 to relieve the Operations Manager.*

6:00 p.m.	NRC management called requesting a discussion of plant status from senior plant management.
6:00 p.m.	After this time, the operators began to review the consequences of a loss of dc power, assuming Bus 6A was not restored, and began to review the emergency plan.
6:15 p.m.	Operations Manager had a telephone conversation with the Plant Manager to discuss status of restoration actions.
6:25 p.m.	Maintenance crew was in standby still waiting for work order to take IR readings of Bus 6A. Requested status and expected completion from Operations Manager By ConEd procedures, the work order cannot be issued until the tagout is completed.
6:30 p.m.	The Operations Manager provided a plant status brief to NRC management on behalf of senior plant management. Following this briefing, NRC resident inspectors remained onsite to observe licensee actions and provide further briefings to NRC management.
6:30 p.m.	**Operators began hanging tags for the Bus 6A protective tagout in preparation for taking IR readings (with oversight by Facility Support Supervisor and Operations Manager).**
6:40 p.m.	**Watch Engineer documented the Online Risk Assessment condition was Red (Daily Risk Factor (DRF) of 196 due to Bus 6A being inoperable. The typical DRF was less than 1.0).**
7:15 p.m.	**Operations Manager, Maintenance Manager and Engineering held a meeting to discuss status.**
7:15 p.m.	The Engineering Supervisor reported the status of work on the TFCs. Engineering noted that there was no acceptable alternate feed to the battery charger from other sources in the same room (such as MCC29 of MCC 26A) due to the lack of electrical separation. Engineering reviews to that time had focused on the separation issue. More time was needed to review load capability of alternative sources. Engineering reported that it would take more time to prepare a satisfactory safety evaluation for the Bus 6A and battery charger TFCs.
8:00 p.m.	**Bus 6A Tagout (990012041) was completed for troubleshooting.**
8:00 p.m.	**Risk Assessment condition confirmed by the Watch Engineer was Red (Core Damage Frequency (CDF) from the online risk monitor was 5.16×10^{-3} due to Bus 6A being out of service).**

8:00 p.m. The Watch Engineer evaluated the plant conditions and noted the DRF was about 200. This result was communicated to the Shift Manager and discussed with the shift crew during the turnover, with emphasis placed on the need to avoid removing any other plant equipment from service. Following the shift turnover, the Watch Engineer confirmed that loss of annunciators would result in an Unusual Event.

8:00 p.m. The Operations Manager met with the System Engineer to discuss the battery discharge. The System Engineer expected the static inverter would disconnect from the 24 dc bus at about 100 volts.

8:05 p.m. Work permit issued to take IR readings of Bus 6A.

8:30 p.m. The Engineering Supervisor consulted with design engineering, who agreed that the plant could not interconnect the safety-related MCCs due to the present plant conditions. This was precluded by the license requirements that the electrical buses be operable, including design requirements for train separation, with the plant operating above 350°F. An alternative approach was discussed using a feed from a MCC outside the 24 battery charger room and a non-1E device with proper electrical isolation. The approach would involve running cables up from the 33 ft elevation. Engineering supervision assigned two additional engineering personnel to the problem at 10:00 p.m.

8:35 p.m. The operators received a report that Bus 6A IR check was satisfactory. Maintenance continued to evaluate the potential transformer circuit associated with the bus.

9:00 p.m. Operators began hanging tagouts on MCC 27A and EDG 23 breaker.

9:00 p.m. The Operations Manager briefed offsite management by telephone. The briefing included the Chief Nuclear Officer, the Plant Manager, the Vice President Nuclear and the Licensing Manager. The plant status was discussed, and the need to declare an Unusual Event per the Emergency Plan due to the potential loss of control room annunciators.

9:15 p.m. The Engineering Supervisor left the site at 9:15 p.m. with three teams in place (2 people per team) working on the Bus 6A, battery charger and waste gas compressor TFCs. A System Engineer continued coordinating engineering activities pending the arrival at the site of another Engineering Supervisor after midnight.

9:47 p.m. Maintenance personnel completed taking IR readings of Bus 6A. Data was reviewed by system engineering and determined to be satisfactory.

9:47 p.m. The work order was returned to the Facility Support Supervisor Bus 6A IR readings were done. The work was extended by about one-half hour for additional data review when electricians noted data anomalies in the IR readings for the potential transformer phases attached to Bus 6A (this was an initiative to assure Bus 6A connected circuits were satisfactory). The data was deemed acceptable after review by the system engineer.

9:55 p.m. 118 V ac Instrument Bus 24 de-energized due to low voltage (less than 105) on Battery 24.

Control Room Annunciators fed from instrument bus 24 became degraded and unreliable.

Operators declared an Unusual Event (UE) in accordance with EAL 7.3.1 - Central Control Room (CCR) Annunciators.

9:55 p.m. When the 24 instrument bus was lost, the Operations Manager made the decision for the plant to be taken below 350° F. The operators noted that the TS LCO required that the battery be restored to service within 24 hours for power operations to continue (above 350° F). Without any recovery mode available, the battery could not be restored within the action time. The Licensing Manager discussed with the Operations Manager the need to take the plant below 350° F per TS 3.0.1. The decision was made to cool down to 350° F, but after Bus 6A and the 24 instrument bus was restored to service.

The loss of the 24 instrument bus caused the 24 steam generator feed regulating valve to fail open, which made steam generator level control difficult. Starting at 10:03 p.m., the operators began stopping and starting the turbine-driven auxiliary feed water pump to control level in steam generator 24.

AIT Note: The Operations Manager stated in an interview that, in hindsight, the crew could have throttled down on AFW supply valves as an alternative means for SG level control and avoid repeated starting and stopping of the AFW pump.

10:03 p.m. Operators secured TDAFW Pump 22 due to steam generator feed regulating valves failing open on the loss of power to instrument bus 24.

10:09 p.m. Operators completed Notifications of the Unusual Event to New York State and local agencies.

10:20 p.m. Maintenance received the Work Order to take IR readings of MCC 27A.

10:39 p.m. Operations personnel notified the NRC of the Unusual Event (EN 36107).

10:57 p.m. Operators started TDAFW Pump 22.

11:00 p.m. The TFC and safety evaluation for Bus 6A interlocks was provided to Nuclear Licensing for review. Although the TFC was close to issue, it was not needed because of the pending actions to re-energize Bus 6A.

11:01 p.m. Operators secured TDAFW Pump 22.

11:20 p.m. Loss of 24 Battery due to low voltage.

Loss of greater than 75% safety related system control room annunciators.

The 24 dc bus voltage stayed high until the inverter went off line, and then the Battery 24 began to degrade rapidly from 10:30 p.m. to 11:20 p.m. Battery voltage decreased over this period from 96 volts to 57 volts.

AIT Note: Once the SI/Instrument bus was lost (9:55 p.m.), there was no basis to keep discharging the battery. The battery was allowed to keep discharging until suspected cell reversal. The battery output breaker was opened at the request of the System Engineer when power was ready to be restored to the battery charger (1:11 a.m. on September 1). The Operations Manager stated, in hindsight, that the crew could have opened up the battery breaker when the Unusual Event was declared.

September 1, 1999

12:00 a.m. The TFC for the 6A undervoltage lockout was finished around midnight after working it for 8 hours. The TFC for the alternate feed to the battery charger was still in progress at midnight when 6A was powered from EDG 23.

12:28 a.m. Bus 6A tagout was cleared.

12:43 a.m. Operators manually started EDG 23 and energized Bus 6A from EDG 23.

When Bus 6A was restored with EDG 23 power, the System Engineer recommended opening the battery output breaker.

12:50 a.m. Operators energized MCC 27A from Bus 6A, and Instrument Bus 24 was restored.

1:11 a.m. DC Bus 24 restored by 24 battery charger.

Control Room Annunciators restored.

The battery charger TFC was subsequently completed on September 1. MCC 26C was used to feed the battery charger with the plant below 350° F. The TFC was installed, but not connected as a backup to the normal feed from MCC 27A.

2:04 a.m. Operators reset Blackout Relays for 480 V buses.

2:18 a.m.	Operators started TDAFW pump 22 to feed Steam Generators 23 and 24.
2:24 a.m.	Bus 5A transferred to offsite power. EDG 21 placed in Auto.
2:36 a.m.	EDG 21 secured.
2:50 a.m.	Buses 2A and 3A transferred to offsite power. EDG 22 placed in Auto.
2:56 a.m.	EDG 22 secured.
3:30 a.m.	Operators exited the Unusual Event.
4:35 a.m.	Operators Initiated plant cooldown.
4:45 p.m.	Reactor coolant system temperature below 350° F.
5:12 p.m.	Battery 24 tagged out.
5:56 p.m.	Reset Turbine Trip/Reactor Trip.
9:08 p.m.	Operators established normal offsite power supply to Bus 6A.
10:10 p.m.	EDG 23 was secured.

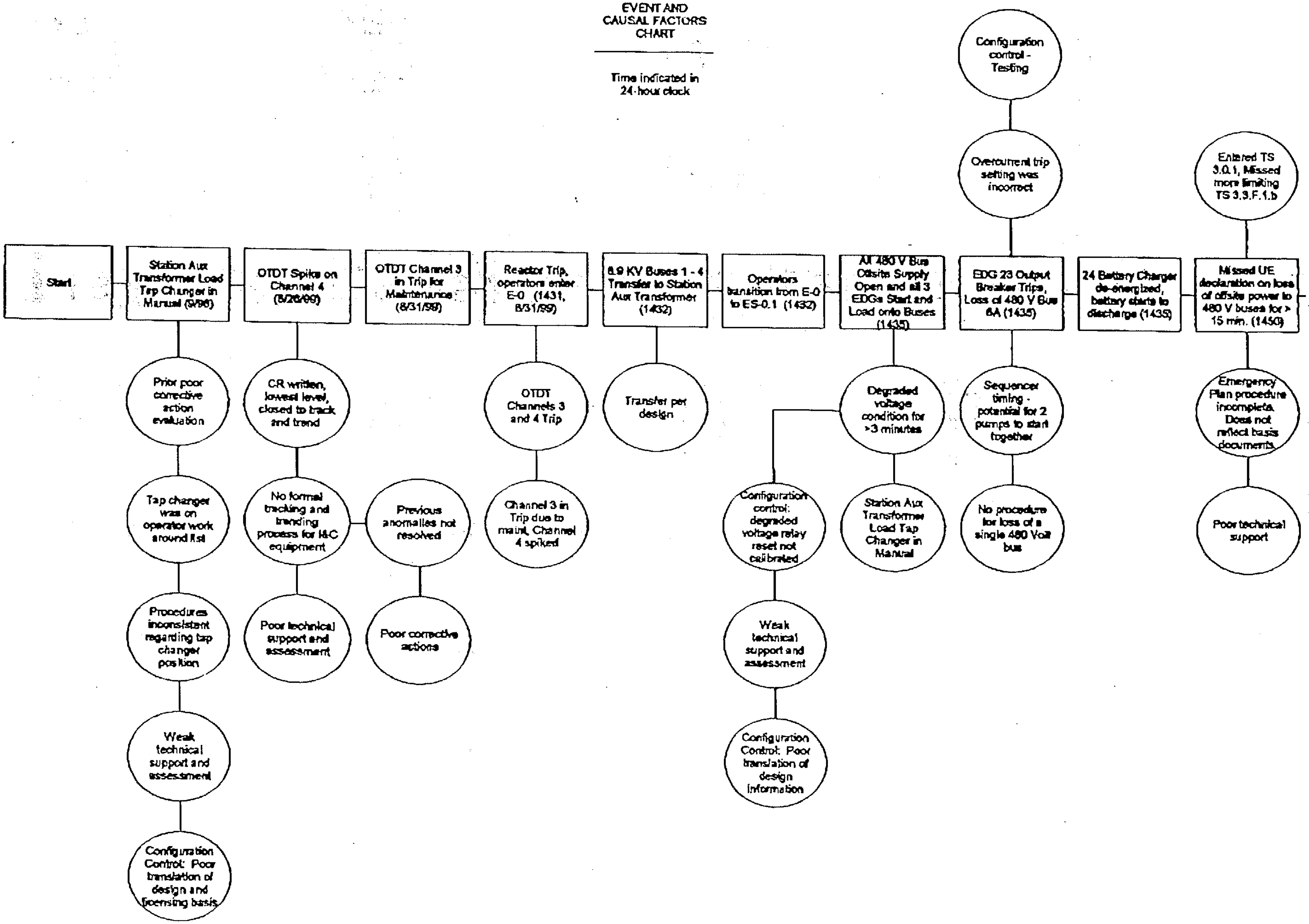
ATTACHMENT 2

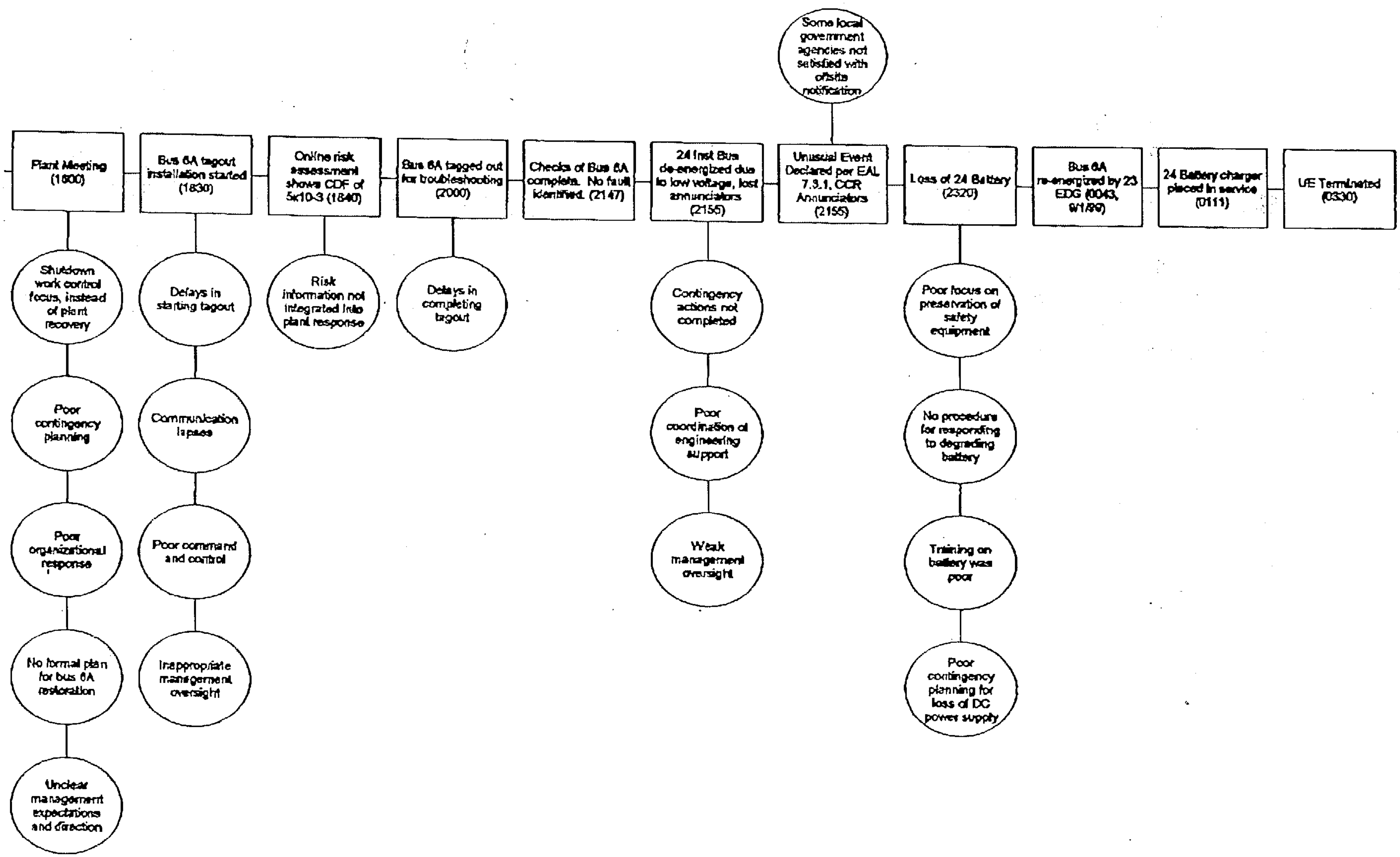
EVENT AND CAUSAL FACTORS CHART

ATTACHMENT 2

EVENT AND CAUSAL FACTORS CHART

Time indicated in 24-hour clock




Plant Meeting (1800)
Bus 6A tagout installation started (1830)
Online risk assessment shows CDF of 5x10-3 (1840)
Bus 6A tagged out for troubleshooting (2000)
Checks of Bus 6A complete. No fault identified. (2147)
24 Inst Bus de-energized due to low voltage, lost annunciators (2155)
Unusual Event Declared per EAL 7.3.1, CCR Annunciators (2155)
Some local government agencies not satisfied with offsite notification
Loss of 24 Battery (2320)
Bus 6A re-energized by 23 EDG (0043, 9/1/99)
24 Battery charger placed in service (0111)
UE Terminated (0330)
Shutdown work control focus, instead of plant recovery
Poor contingency planning
Poor organizational response
No formal plan for bus 6A restoration
Unclear management expectations and direction
Delays in starting tagout
Communication lapses
Poor command and control
Inappropriate management oversight
Risk information not integrated into plant response
Delays in completing tagout
Contingency actions not completed
Poor coordination of engineering support
Weak management oversight
Poor focus on preservation of safety equipment
No procedure for responding to degrading battery
Training on battery was poor
Poor contingency planning for loss of DC power supply