January 27, 2003

Mr. Fred R. Dacimo
Site Vice President
Entergy Nuclear Operations, Inc.
Indian Point Nuclear Generating Unit 3
295 Broadway, Suite 3
Post Office Box 308
Buchanan, NY 10511-0308

SUBJECT: INDIAN POINT 3 NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT NO. 50-286/02-08

Dear Mr. Dacimo

On December 28, 2002, the NRC completed an inspection at the Indian Point 3 Nuclear Power Plant. The enclosed report presents the results of that inspection. The results were discussed on January 20, 2003, with Mr. Chris Schwarz and other members of your staff.

The inspection was an examination of activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations, and with the conditions of your license. Within these areas, the inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel. Based on the results of the inspection, no findings of significance were identified.

Since the terrorist attacks on September 11, 2002, the USNRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve readiness, and enhance access authorization. The USNRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. The TI 2515/148 audit was completed at all commercial nuclear power plants during calender year (CY) '02, and the remaining inspections are scheduled for completion in CY '03. Additionally, table-top security drills were conducted at several licensees to evaluate licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Safety and Incident Response. For CY '03, the USNRC will continue to monitor overall safeguards and security controls, conduct inspections, and perform force-on-force exercises at selected power plants to pilot a long-term program that will test the adequacy of licensee security and safeguards strategies. Should threat conditions change, the USNRC may issue additional Orders, advisories, and temporary instructions to contribute to the assurance of safety.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room **or** from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Peter W. Eselgroth, Chief
Projects Branch 2
Division of Reactor Projects

Docket No. 50-286
License No. DPR-64

Enclosure: Inspection Report No. 50-286/02-08

Attachment: Supplemental Information

cc w/encl:
J. Yelverton, Chief Executive Officer
M. Kansler, Senior Vice President and Chief Operating Officer
C. Schwarz, General Manager of Plant Operations
D. Pace, Vice President - Engineering
J. Knubel, Vice President Operations Support
J. Kelly, Director - Licensing
C. D. Faison, Manager - Licensing
H. P. Salmon, Jr., Director of Oversight
J. Comiotes, Director, Nuclear Safety Assurance
J. McCann, Manager, Nuclear Safety and Licensing
Mayor, Village of Buchanan
J. G. Testa, Mayor, City of Peekskill
J. M. Fulton, Assistant General Counsel
W. Flynn, President, New York State Energy Research and Development Authority
J. Spath, Program Director, New York State Energy Research and Development Authority
P. D. Eddy, Electric Division, New York State Department of Public Service
C. Donaldson, Esquire, Assistant Attorney General, New York Department of Law
R. Schwartz, SRC Consultant
R. Toole, SRC Consultant
C. Hehl, SRC Consultant
R. Albanese, Executive Chair, Four County Nuclear Safety Committee
S. Lousteau, Treasury Department, Entergy Services, Inc.
Chairman, Standing Committee on Energy, NYS Assembly
Chairman, Standing Committee on Environmental Conservation, NYS Assembly
Chairman, Committee on Corporations, Authorities, and Commissions
Assemblywoman Sandra Galef, NYS Assembly
C. Terry, Niagara Mohawk Power Corporation

County Clerk, Westchester County Legislature
A. Spano, Westchester County Executive
R. Bondi, Putnam County Executive
C. Vanderhoef, Rockland County Executive
E. A. Diana, Orange County Executive
M. Elie, Citizens Awareness Network
J. Riccio, Greenpeace
F. Zalcman, Pace Law School, Energy Project
A. Matthiessen, Executive Director, Riverkeeper, Inc.
P. Leventhal, The Nuclear Control Institute
K. Copeland, Pace Environmental Litigation Clinic
R. Witherspoon, The Journal News

Distribution w/encl: H. Miller, RA/J. Wiggins, DRA (1)
H. Nieh, RI EDO Coordinator
R. Laufer, NRR
P. Milano, PM, NRR
G. Vissing, Backup PM, NRR
P. Eselgroth, DRP
W. Cook, DRP
R. Martin, DRP
P. Drysdale, SRI - Indian Point 3
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No. 50-286

License No. DPR-64

Report No. 50-286/02-08

Licensee: Entergy Nuclear Northeast

Facility: Indian Point 3 Nuclear Power Plant

Location: 295 Broadway, Suite 3
Buchanan, NY 10511-0308

Dates: September 29 - December 28, 2002

Inspectors: P. Drysdale, Senior Resident Inspector
M. Cox, Resident Inspector
W. Cook, Senior Project Engineer
T. Jackson, Project Engineer
J. D'Antonio, Operations Engineer
J. O'Hara, Operations Engineer
J. Jang, Senior Health Physicist
J. McFadden, Radiation Specialist
W. Schmidt, Senior Reactor Inspector
S. Chaudhary, Senior Reactor Inspector
K. Young, Reactor Inspector
P. Frechette, Security Specialist
A. Dimitriadis, Security Specialist

Approved by: Peter W. Eselgroth, Chief
Projects Branch 2
Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000286/02-08, on 09/29 - 12/28/2002, Entergy Nuclear Northeast, Indian Point 3 Nuclear Power Plant. Integrated resident inspection report.

The inspection was conducted by resident and regional inspectors. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 3, dated July 2000.

A. Inspector Identified Findings

None

B. Licensee Identified Violations

None

TABLE OF CONTENTS

Report Details

SUMMARY OF PLANT STATUS

At the beginning of the inspection period, the Indian Point 3 (IP3) reactor was at full power.

On November 15, 2002, the 345 kilovolt (KV) output breaker No. 3 experienced a ground fault in the “B” phase, which caused the breaker to trip open. The automatic fault isolation immediately caused the adjacent breakers (Nos. 1 and 5, and disconnect switch No. F1-3) to open, and a full generator load rejection resulted. These events caused the turbine to trip off line, which was followed by an automatic reactor trip. The plant remained shutdown in hot standby (mode 3) for investigation into the cause of the ground fault and corrective maintenance on breakers 1 and 3. The reactor was returned to criticality following maintenance on breaker no. 1, and the generator synchronized to the grid on November 22.

On December 11, 2002, reactor power was reduced to approximately 70% due to a hot spot on the 345KV disconnect switch No. 4B in the Buchanan switchyard. That was followed by a subsequent power reduction on December 12, to approximately 60%, and further to approximately 48% on December 13, due to a hot spot on disconnect switch No. F3-5. Following the repairs to breaker No. 3 and disconnect switch F3-5, plant power was raised to approximately 82% on December 14. After the repair of switch 4B, the plant was returned to 100% power on December 16. The plant remained of power through the end of the inspection period.

1. REACTOR SAFETY
(Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness)

1R01 Adverse Weather Protection

a. Inspection Scope (71111.01)

The inspectors reviewed procedure OD-37, “Seasonal Weather Preparation,” and the attached cold weather preparations checklists to verify that the checklists were completed in accordance with procedure requirements. The inspectors also verified that the actions taken by the licensee to assure freeze protection of plant equipment were completed on time, and were adequate for winter conditions at the plant during October, November, and December 2002. The inspectors performed system walkdowns inside plant spaces to assess the functionality of these systems, and verified that they were free from adverse effects of low temperatures. Following the period of significant snowfall on November 26 & 27, the inspectors toured external areas of the plant to assure that the licensee prevented snow and ice accumulation from impairing the operation of plant equipment, and maintained access to the equipment by plant personnel.

The inspectors also reviewed the list of outstanding work requests that were related to cold weather and noted that there were still some backlog items in the old work control system (ROME) that had not yet been converted to the current system (MAXIMO). The inspectors reviewed these items with the responsible work control unit coordinator. The inspectors were satisfied that no significant items, susceptible to cold weather, would be unscheduled during conversion to the new work control system.

The inspectors reviewed temporary modifications (TMs) currently installed in the plant, and verified that the OD-37 checkoff list did not identify any TMs requiring special provisions for cold weather protection. The inspectors performed a field walkdown of TM 01-3-099, “PCE thermostat,” dated January 17, 2002 (WR# I3-010489201, “Jumper PCE building outdoor thermostat node T1N”), to confirm the TM was not adversely impacted by cold weather.

b. Findings

No findings of significance were identified

1R02 Evaluations of Changes, Tests, or Experiments

a. Inspection Scope (IP 7111102)

The inspectors reviewed selected safety evaluations categorized under the NRC Reactor Safety Cornerstones (event initiator, barrier integrity, and mitigating systems) to verify that the licensee had appropriately considered the conditions under which changes to the facility or procedures may be made, or tests conducted, without requiring prior NRC approval. The inspectors also reviewed selected design change packages (DCPs) and nuclear safety evaluations (NSEs) for which the licensee had determined, through screening evaluations, that additional evaluations were not required in accordance with 10 CFR 50.59, “Changes, tests, and experiments.” The inspectors verified that the licensee’s conclusions to screen-out these changes (from performing full safety evaluations) were correct and consistent with 10 CFR 50.59. The inspectors selected safety evaluations and screen-outs for review based on the safety significance of the changes and the resulting risk to applicable structures, systems, and components (SSCs). A listing of the safety evaluations, safety evaluation screens, and other documents reviewed is provided in Attachment A to this report.

Through follow-up discussions with plant staff and the review of information associated with DCPs and NSEs, such as calculations, supporting analyses, regulatory references, and plant drawings, the inspectors assessed whether the licensee had appropriately concluded that the changes could be accomplished without obtaining a license amendment. In addition, the inspectors reviewed the administrative procedures that were used to control the screening, preparation, and issuance of the safety evaluations to ensure that the administrative procedures adequately covered the requirements of 10 CFR 50.59.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (Quarterly)

a. Inspection Scope (71111.04Q)

The inspectors performed system alignment and material condition walkdowns during periods of redundant system/train unavailability to verify that the operable train was capable of providing its safety function. The inspectors also verified that the licensee had properly identified any equipment discrepancies that could potentially impair the functional capability of the safety systems.

- On November 27, 2002, the inspectors performed a partial system walk down of equipment in the 31 & 33 safety injection (SI) trains during the quarterly surveillance test of the 32 SI pump (3PT-Q116B). The inspectors checked existing deficiency tags to assure that conditions on the 31 & 33 SI pumps did not adversely impact system operability. The 32 SI pump test was followed by 15-minute monthly runs of the 31 & 33 pumps. The inspectors performed similar walkdowns of the other standby pumps during each of these tests.

- On December 20, 2002, the inspectors performed a partial walkdown of the 31 and 32 trains of the auxiliary boiler feedwater system to verify proper standby alignment during the performance of the 33 auxiliary boiler feedwater pump (ABFP) quarterly surveillance test (3PT-Q120C), which rendered the 33 train inoperable. The inspectors verified the proper restoration of the 33 ABFP at the completion of the surveillance.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (Semi-annual)

a. Inspection Scope (71111.04S)

Between November 11 and December 28, 2002, the inspectors performed a comprehensive walkdown of the service water system, including both the essential and non-essential supply headers, and all system piping, pumps, valves, heat exchangers, and instruments. The service water system was selected because of its significant (7%) contribution to the calculated core damage frequency, as described in the Individual Plant Evaluation (IPE). The inspectors walked down approximately 90% of the service water system (outside containment) to verify proper system alignment for full power operations, in accordance with checkoff lists COL-RW-2, “Service Water System,” and COL-RW-2A, “Service Water Header Realignment.” The inspectors also verified that all valves essential to service water system operation, as noted on flow diagram No. 9321-F-27223, “Service Water,” were properly designated in the checkoff lists.

b. Findings

No findings of significance were identified

1R05 Fire Protection

a. Inspection Scope (71111.05Q)

The inspectors conducted fire protection tours in the fire zones listed below to ensure that the licensee was controlling transient combustibles in accordance with fire protection procedure FP-9 “Control of Combustibles;” to ensure that the licensee had been controlling ignition sources in accordance with FP-8, “Controlling of Ignition Sources”; to ensure that the licensee had provided the fire protection equipment specified in the Pre-Fire Plans (PFPs) listed below; and to assess the general material condition of the fire protection equipment and fire protection barriers. These areas were selected for inspection based on their relative fire initiation risk and the safe shutdown equipment located in the areas.

- Fire Zone 20: on November 5 - 7, 2002, the inspectors performed a walk-through of the main boiler feed pump (MBFP) oil storage area on the 5-foot elevation of the turbine building using PFP-34, “MBFP Oil Storage.” The inspectors noted that most of the floor area below both MBFPs had a significant amount of oil that had dripped down from the MBFPs above. This condition could have created a safety hazard for fire brigade members, if they needed to access fire fighting equipment in the area. The inspectors brought this condition to the licensee’s attention for resolution.

- Fire Zone 18: on November 13, 2002, the inspectors performed a walkdown of the central control room using PFP-28, “Control Room - Control Building.”

- Fire Zone 59a: on November 25 - 26, 2002, the inspectors performed walkdowns of the upper and lower pipe penetration areas (51-foot and 41-foot elevations) adjacent to the primary auxiliary building using PFP-16, “Upper Pipe Penetration Area - Fan House Elevation 54-foot.”

- Fire Zones 7A & 11: on December 9, 2002, the inspectors performed an inspection of the cable spreading room and the lower cable tunnel using PFP-27, “Cable Spreading Room/Battery Rooms.”

- Fire Zones 14, 33A, & 35A: on December 10, 2002, the inspectors performed an inspection of the 480 volt switchgear room, the control room air conditioning room, and the main transformer deluge valve room, using PFP-25, “480V Switchgear Room.”

- Fire Zones 5A, 61A, & 62: on December 12, 2002, the inspectors performed an inspection of the service water valve and mini-containment area using PFP-6A, “Mini Containment and Pipe Tunnels.”

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope (71111.06)

The inspectors reviewed the licensee's latest revisions to the procedures for response to an internal flooding event as described in off-normal procedure ONOP-RW-3, "Plant Flooding," operations directive OD-8, "Guidelines for Severe Weather," and alarm response procedure ARP-7 , "Panel SDF - Turbine Recorder." The inspectors used these procedures to tour areas important to safety inside and outside the plant to assess the condition of flood mitigation equipment described in the Final Safety Analysis Report (FSAR). The inspectors assessed the condition of the major flow channels in the floor of the 15 ft. turbine building designed to divert the flow of water from a potential break of a main circulating water pipe away from the 6.9 KV switchgear, the 480 VAC switchgear, and the emergency diesel generator rooms. The inspectors noted several plant floor drains in the turbine and primary auxiliary buildings that appeared to be partially blocked by debris, and referred these items to the licensee for resolution. The inspectors also walked down external areas of the plant following significant snowfalls to assess the flow paths for runoff from snow melt, and the susceptibility to water intrusion at entrances into plant spaces.

b. Findings

No findings of significance were identified.

1R07 Heat Sink

a. Inspection Scope (71111.07A)

On October 22 and 24, the inspectors observed workers open the 31 instrument air closed cooling (IACC) heat exchanger (HX) for a scheduled inspection and cleaning. The HX contained a large amount of silt that was deposited in the outlet plenum, where the service water flow exiting the HX made an abrupt 90 degree turn. The inspectors discussed, with cognizant component engineers, the potential significance of these conditions to the thermal performance of the HX. Although the accumulation in the plenum was significant, it did not block more than 10% of the tubes and did not affect the thermal performance capability of the HX. The inspectors also evaluated the preventive maintenance frequency of the IACC HXs, in light of the conditions observed.

On October 29 and 30, the inspectors observed the licensee open the 33 EDG jacket water and lube oil HXs for scheduled inspections and cleaning. The jacket water HX's inlet and outlet chambers contained fragments of zinc from the sacrificial anode installed inside, but very little silt was present. The lube oil cooler inlet and outlet chamber also contained zinc fragments, but no tube blockage was observed. The reversing chambers in both HXs had several large zinc fragments, but no silt had accumulated in these areas. The inspectors noted that the inlet side of the lube oil HX had several small barnacles attached to its internal surface. However, no barnacles or shells blocked the cooling tubes and no barnacles were present on any other internal surface. The inspectors discussed the presence of marine animals in the HX and the effectiveness of the chlorination system with the cognizant envirnomental supervisor to determine the potential for this type of growth to exist in other portions of the service water system (see section 1R12 below).

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (Quarterly)

a. Inspection Scope (71111.11Q)

On December 9, 2002, the inspectors observed simulator training for licensed operators of Team "E" (4th quarter 2002 requalification cycle). The inspectors reviewed the simulator scenario, documented in Lesson Plan No. LRQ-SES-35, "SGTR/Faulted SG," to determine if the scenario contained: 1) clear event descriptions with realistic initial conditions; 2) clear start and end points; 3) clear descriptions of visible plant symptoms for the crew to recognize; and 4) clear expectations of operator actions in response to abnormal conditions.

During the simulator exercise, the inspectors evaluated the team's performance for: clarity and formality of communications; correct use and implementation of emergency operating procedures (EOPs) and off-normal operating procedures (ONOPs); operators' ability to properly interpret and verify alarms; and, operators' ability to take timely actions in a safe direction, based on transient conditions. In addition, the inspectors evaluated the control room supervisor's ability to exercise effective oversight and control of the crew's actions during the exercise.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (Annual)

a. Inspection Scope (71111.11A)

The following inspection activities were performed using the acceptance criteria of NUREG-1021, Rev. 8, "Operator Licensing Examination Standards for Power Reactors," Inspection Procedure Attachment 71111.11, "Licensed Operator Requalification Program," and NRC Inspection Manual, Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP."

The inspectors selected, for training evaluation, Condition Report (CRs) related to plant operating history and operator performance, and two recent events involving an inadvertent dilution and a turbine runback. The inspectors verified that both of these topics were addressed in current training. The inspectors noted that the operating crew that had recently experienced the NI failure/turbine runback had just completed training on that topic.

The inspectors reviewed two examples of the last comprehensive written examination (administered by the licensee May - July 2002), and witnessed the administration of an operating examination to one crew. The operating examination consisted of three simulator scenarios and one set of five job performance measures. The inspectors verified that the examination materials satisfied the criteria of the examination standards and 10 CFR 55.59, “Requalification.”

The inspectors observed simulator performance during the conduct of the examinations and reviewed performance testing and discrepancy reports to verify compliance with the requirements of 10 CFR 55.46, “Simulation Facilities.” The most recent steady state test and transient tests for plant startup, reactor trip, and loss of the residual heat removal (RHR) function were reviewed.

Instructors, training/operations management personnel, and selected licensed operators were interviewed for feedback regarding the implementation of the licensed operator requalification program.

On October 18, 2002, the inspectors conducted an in-office review of requalification exam results. These results included the annual operating test and comprehensive written exam. The inspection assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP)”. The inspectors verified that:

- The team pass rate was greater than 80%. (The actual pass rate was 100%.)
- The individual pass rate on the dynamic simulator test was greater than or equal to 80%. (The actual pass rate was 94%.)
- The individual pass rate on the walk-through test was greater than or equal to 80%. (The actual pass rate was 100%.)
- The individual pass rate on the comprehensive written exam was greater than or equal to 80%. (The actual pass rate was 96%.)
- The overall pass rate among individuals for all portions of the exam was greater than or equal to 75%. (The actual pass rate was 89%.)

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope (71111.12)

The inspectors reviewed the following systems and components, and recent performance issues, to assess the effectiveness of the licensee’s Maintenance Rule program. Using 10 CFR 50.65, “Requirements for monitoring the effectiveness of maintenance at nuclear power plants,” and Regulatory Guide 1.1.60, “Monitoring the effectiveness of maintenance at nuclear power plants," the inspectors verified that the licensee was implementing their Maintenance Rule program in accordance with NRC regulations and guidelines, properly classifying equipment failures, and using the appropriate performance criteria for Maintenance Rule systems in 10 CFR 50.65 (a)(2) status.

The inspectors also reviewed the performance of maintenance and associated post-maintenance test (PMT) activities to assess whether: 1) the effect of maintenance on plant equipment had been adequately addressed by control room personnel; 2) work planning was adequate for the maintenance performed; 3) the acceptance criteria were clear and adequately demonstrated operational readiness, consistent with design and licensing documents; and, 4) the equipment was properly returned to service. The following maintenance activities were observed and evaluated:

- <u>Chlorination Action Plan</u>:

  The licensee noted the presence of Zebra and "Dark False" mussels in the Hudson River in the vicinity of IP3 and in the service water system during macro-fouling monitoring on July 8, 2002 (CR-IP3-2002-2607). The CR stated that the number of individual mussels found were consistent with historical numbers, but were found earlier in the year than usual. It also emphasized a need for more effective chlorination of the plant's intake water. The inspectors evaluated the presence of zebra mussels in the service water system and discussed the effectiveness of chlorination, with chemistry and engineering personnel, for preventing an infestation of mussels which could decrease the thermal performance of safety-related heat exchangers. The inspectors had noted that several barnacles and shell fragments were found in the 33 EDG jacket water cooler, during preventive maintenance on October 29, 2002 (see section 1R07 above), and during preventive maintenance on the 32 central control room (CCR) air conditioning (A/C) unit on October 15 and 10. Zebra mussel shells were also found in the strainer upstream of the A/C heat exchanger, and approximately 30 live animals were found in a "bio-box" located downstream of this strainer.

  Since early June 2002, the licensee had been chlorinating the service water system at maximum capacity, but had been unable to maintain the minimum residual value (0.2 parts per million) needed to effectively prevent marine animals from establishing a presence in plant service water systems. The increase in required chlorine injection was attributed to an increase in overall organics in the river water, which consumed the chlorine at a higher than normal rate. The IP3 chlorination system has a 1400 gallon storage tank and a pump with maximum delivery rate of 36 gallons per hour (gph). At the maximum pump rate, the volume in the storage tank will not last much more than 30 hours, and daily chlorine deliveries to the station were required. On several recent occasions, daily deliveries were missed and chlorine injections had to be secured.

  The inspectors reviewed the licensee's chlorination action plan (IP3-APL-02-004) and discussed the licensee's short term actions with cognizant engineering personnel. The plan includes: 1) securing one service water pump when temperature and pressure allow a decrease in flow; 2) inspection of the 32 CCR A/C HX during its next preventive maintenance inspection; 3) tracking and trending the EDG jacket water and lube oil temperatures; and, 4) inspecting other HXs, as appropriate. The licensee anticipated that the presence of mussels in the river would decrease with lower river temperatures in the winter months. The action plan also identified longer term measures, which were: to evaluate the adequacy of a 0.2 parts per million residual chlorine concentration; a proposed system modification to tie the IP3 storage tank into a larger tank at IP2; and, to install higher capacity injection pumps by March 2003. Throughout the remainder of the inspection period, the inspectors evaluated the licensee's actions to monitor the presence of marine animals in plant systems, and verified that the ongoing chlorination was effective.

- <u>345KV Output Breaker No. 3 Overhaul:</u>

On November 15, 2002, 345KV output breaker No. 3 suffered a catastrophic failure due to improper contact alignment and high contact resistance that resulted in a ground fault on the "B" phase (CR-IP3-2002-04550). This resulted in extensive internal damage to the breaker and a subsequent reactor trip. The inspectors reviewed the licensees root cause analysis for this failure. The analysis concluded that the most likely cause was during the last preventive maintenance activitiy (2001), poor maintenance practices and workmanship led to contact misalignment. Consequently, the licensee implemented corrective actions to place quality assurance holds for independent verifications on all subsequent 345KV breaker maintenance performed in accordance with procedure BKR-008-ELC, "138KV and 345KV Sulphur Hexaflouride (SF_6) Breaker Inspection."

Following the November 15 failure, Entergy contracted the original equipment manufacturer to perform the breaker No. 3 overhaul and to restore the breaker to its original specifications. The inspectors observed portions of the overhaul and evaluated the associated work practices. The inspectors also evaluated how the licensee addressed breaker No. 3 under their Maintenance Rule (10 CFR 50.65) Program, including breaker unavailability time calculations and whether the specified performance criteria were commensurate with the safety function of the 345KV system. The licensee determined that this breaker failure was a maintenance preventable functional failure (MPFF) since the previously conducted maintenance was considered to be within the skill of the craft, but incorrectly performed and without adequate procedures. The inspectors evaluated this determination and the subsequent corrective actions to prevent a recurrence.

- <u>Station Auxiliary Transformer Voltage Sensing Relay Failure:</u>

On November 25, 2002, the control room received a "station auxiliary transformer hang-up" alarm after the station's 6.9KV buses 1 and 6 could not be automatically maintained below 7.2KV by the station auxiliary transformer (SAT) tap changer (CR-IP3-2002-04677). This required a control room operator to place the tap changer in manual and to adjust the SAT output voltage down to an acceptable level for the 480V safeguards busses. Since the tap changer did not respond properly, when placed back into automatic, a dedicated operator was assigned to monitor the 480V buss voltages, and to maintain the appropriate SAT output voltage manually in accordance with standard operating procedure SOP-EL-11, "Operation of Main or Auxiliary Transformers."

The licensee developed an action plan (IDSE-APL-02-013) to troubleshoot and investigate this tap changer problem. The inspector observed and discussed the troubleshooting with engineering and I&C personnel. The licensee determined that the voltage sensing relay associated with the tap changer had failed high, and that the relay would have to be replaced. The inspectors observed tests on both the replacement relay and the failed relay conducted in the I&C shop. The inspectors also reviewed the licensee's failure analysis which identified a failed electronic chip in the relay circuit assembly. The chip failure was caused by weather induced corrosion.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Control

a. Inspection Scope (71111.13)

The inspectors reviewed the maintenance risk assessments and corrective maintenance work packages for the below listed emergent and scheduled work, and discussed the degraded conditions with cognizant plant personnel (system engineers, maintenance workers, and technicians).

- Leakage Past Valve CH-HCV-133:

  On October 20, 2002, the licensee discovered that the discharge pressure of the RHR pumps was reading approximately 300 psig when the pumps were not operating. This was significantly higher than the normal pressure, which is approximately 43 psig (due to the supply head pressure from the refueling water storage tank). The licensee generated CR-IP3-2002-04280 to document this problem and initiated an investigation into the source of the pressure increase. The initial investigation revealed that the most likely source was leakage through valve CH-HCV-133, which had shown signs of physical degradation during diagnostic testing in March 2001. CH-HCV-133 is a normally closed air-operated valve that is used to divert part of the RHR flow into ion exchanger beds in the chemical and volume control system (CVCS) during normal RHR system operation. The inspectors reviewed the results of the diagnostic tests for CH-HCV-133, documented in WR#00-01407-09, which revealed minor wear and bending of the valve stem, but indicated no evidence of plug or cage binding.

  The licensee developed an action plan (No. IDSE-APL-02-011) to investigate possible leakage past CH-HCV-133. The inspectors reviewed the action plan with the system engineer and observed troubleshooting (WR Nos. IP3-02-21153, & -21220). The inspectors also discussed the situation with the operations shift manager and the RHR system engineer, and evaluated the operational risk assessments for the leak and for troubleshooting the valve. The inspectors noted that the leakage past CH-HCV-133 was limited by the maximum pressure on the downstream side of the CVCS letdown flow orifices (approximately 250 psi), and would not have exceeded the RHR system design pressure of 600 psi.

The licensee stroked the valve several times from the control room, but was not able to achieve full closure. During the stroking exercises, operations and engineering personnel determined that the valve's positioner was not fully effective in closing the valve. However, the valve was fully seated by relieving the air pressure on its actuator. The licensee then vented the RHR piping and restored air pressure to the valve's actuator. The licensee concluded that the valve and its positioner was defective and would be replaced during the next refueling outage. The inspectors reviewed the potential operational risks associated with CH-HCV-133 leakage during RHR pump surveillance tests and discussed this condition with the operations shift manager.

- <u>Service Water Valve SWN-45-2 Failure and Repair</u>:

  On October 28, 2002, the control room received a service water header high pressure alarm and operators noted that pressure had increased from approximately 92 to 102 psi (CR-IP3-2002-04372). In accordance with the alarm response procedure (ARP), operators reduced the header pressure by stopping one of the operating pumps on the essential service water header and placing a Zurn strainer in the manual mode to relieve header pressure. The licensee immediately investigated the FCU discharge piping which revealed that two of the four mounting fasteners on the manual operator for valve SWN-45-2 (10-inch manual butterfly isolation valve for FCU temperature control valve TCV-1103) had sheared off, and two fasteners had unthreaded. The failure was apparently caused by flow-induced vibration in the piping which caused the fasteners to loosen. The valve disc caused a flow blockage after it separated from the actuator. Operators immediately opened the manual bypass valve (SWN-46) to restore normal discharge flow. As a result, containment temperature had increased from approximately 92F to 104F and pressure from 0.5 to 1.06 psi. Control room operators relieved containment pressure while normal FCU discharge flow was restored.

  The inspectors reviewed the licensee's response procedures and the risk assessment for completing an online repair of SWN-45-2. The event did not affect the FCU discharge flow paths used during design basis conditions (i.e., through 18-inch valves TCV-1104 and -1105), which are automatically available following a safety injection signal. The inspectors also reviewed the repair package (WR No. IP3-02-21639) used to replace and retest the actuator on SWN-45-2. Manual bypass valve SWN-46 was opened during the replacement to assure sufficient discharge flow while temperature control valve TCV-1103 was shut. The inspectors also reviewed the licensee's equipment failure analysis which confirmed the failure mode for the fasteners was cyclic fatigue. The inspectors discussed the loose fasteners with cognizant component engineers who concluded that the fasteners were not sufficiently torqued when the valve was replaced during the last refueling outage.

- <u>480 Volt Undervoltage (UV) Relay Failure</u>:

  While performing routine rounds on November 12, 2002, a control room operator noted that the "480 Volt UV Relays Functioning" light was not lit on safeguards bus 5A as required. Operators contacted instrumentation and controls (I&C) technicians for troubleshooting and initiated CR-IP3-2002-04524. The problem was traced to failed contacts on the voltage sensing relay associated with bus 5A. When the relay senses a low bus voltage (from a degraded grid voltage or a loss of offsite power) it initiates the automatic start sequence for the 33 EDG. The inspectors reviewed the work request package (WR#IP3-02-01331), evaluated the licensee's troubleshooting, and observed the work to replace the relay. The inspectors also evaluated the licensees risk assessment for the relay failure and the subsequent online repair. Upon completion of the repair, the inspectors observed surveillance 3PT-M62, "480V Undervoltage/Degraded Grid System Functional Test," which the licensee performed to verify proper operation of the relay.

b. <u>Findings</u>

No findings of significance were identified.

1R14 <u>Personnel Performance During Non-routine Plant Evolutions and Events</u>

a. <u>Inspection Scope</u> (71111.14)

- On October 17, 2002, the inspectors observed a special evolution to evaluate the use of the Unit 3 Appendix R diesel generator to supply emergency electrical loads at IP2. The inspectors observed the test and discussed the procedure requirements with operations personnel operating the diesel engine. The inspectors noted that the operators did not perform a switch manipulation on two separate occasions when acquiring phase current data. The inspectors also noted an unsafe industrial work practice when an operator reached into an energized panel to operate a knife switch. The licensee generated CR-IP3-2002-4265 to address these observations.

- On October 30, 2002, the inspectors observed a special evolution for borating the 31 CVCS mixed bed demineralizer prior to placing it in service. The inspectors reviewed the required procedures for this evolution (SOP-CVCS-004, SOP-CVCS-002, and AP-19.1) and attended the pre-job briefing. During the evolution, the inspectors noted that operators took several actions that were not specified in the procedure (i.e., to raise the volume control tank level to 60% and to put the charging pumps in manual). The licensee stated that the procedure would work as written, but the additional steps enhanced the efficiency and control of the evolution. This had been found through the operational experience program and was being maintained in their pre-job briefing database The inspectors evaluated the additional steps and found they did enhance the control of the process and minimized the impact of the evolution on other plant parameters. After review, the licensee determined that these actions should more appropriately be added to the procedure. Document feedback form IP3-6190 was subsequently written to initiate a procedural change.

- On November 15, 2002, the reactor automatically tripped following a main generator load reject and turbine trip, caused by a catastrophic fault in 345KV output breaker No. 3 (Event Notification #39375). The inspectors observed the operators' response to the trip and assessed communications and use of procedures during the subsequent shutdown of the plant. The inspectors also evaluated operators' response to several minor equipment anomalies that occurred during the plant shutdown. The inspectors reviewed the required notifications made by the licensee to assure they were complete and timely.

  Shortly after the trip, the licensee formed a Post Transient Review Group (PTRG), which conducted interviews of all control room operators who responded to the event and gathered all the pertinent plant systems data in order to analyze the plant's response. The inspectors discussed aspects of the event with PTRG members and assessed the group's investigative activities.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope (71111.15)

The inspectors reviewed selected CRs that identified degraded or non-conforming conditions that potentially impacted equipment operability. The inspectors reviewed the resulting operability determinations (ODs) for technical adequacy, whether or not continued operability was warranted, and to what extent other degraded systems or conditions may adversely impact the affected system or compensatory actions. The following CRs and ODs were evaluated:

- CR-IP3-2002-04039; Potential for clogging SI throttle valves. On October 3, 2002, the licensee documented a potential problem with SI branch line throttle valves that could be throttled to an opening size that is smaller than the containment and recirculation sump screen openings (1/8 inch). Branch valves SI-MOV-856D, -856F, 856J, -856C, and 856E were determined to be throttled to less than the sump screen size.

  OD 02-34: On October 4, 2002, the licensee issued OD 02-34 which concluded that the clogging of SI branch valves was highly unlikely due to the vertical configuration of the containment and recirculation sump screens above concrete barriers where small solid particles would be deposited before passing through the screens. Also, small particles that could be light enough to float and pass through the screens would be pulverized by the SI or recirculation pump impellars, and would not clog the branch line valves due to the high differential pressure across the valves. The inspectors reviewed the engineering analysis contained in the OD, which detailed multiple post-accident scenarios involving recirculation flow inside containment, and discussed its conclusions with the engineers who performed the analysis.

- CR-IP3-2002-04120: During a routine inspection inside the containment building on October 8, 2002, the licensee discovered a tool bag on the lowest elevation that had apparently been left at the base of the 34 steam generator during the last refueling outage. The bag contained several common tools and materials such as wrenches, wire, and tape.

  OD 02-35: The licensee evaluated the size and quantity of tools and materials for potential clogging of the containment sumps and the recirculation pumps, and for potential detrimental effects on the chemistry of recirculation fluids. The inspectors reviewed the evaluation, which concluded that there was an insufficient amount of material in the bag to have any detrimental effects on recirculation fluids or the containment environment. In all cases, the size of the screen mesh over the containment sumps was sufficiently small to prevent solid tool and materials from passing into the sumps. The bag itself was approximately three square feet in area and would not block a significant amount of flow into any containment sump (approximately 40-50 square feet screen surface area).

- CR-IP3-2002-04388: During a test of the 33 EDG fuel oil storage tank on October 29, 2002, the licensee observed a significant amount of external corrosion on the tank's emergency fill line (#1050). The pipe is located inside a valve pit, above the storage tank, that is often subjected to high humidity and rain water intrusion. The inspectors reviewed the CR and evaluated the licensee's short and long term corrective actions, which included replacement of the pipe during the next refueling outage and the application of protective insulation.

  OD 02-37: The licensee examined the pipe on October 30, using non-destructive ultrasonic test (UT) methods to determine the extent of wall thining in the corroded areas. Engineering personnel also generated calculation IP3-CALC-EDG-03703, "Operability Determination of Corroded Pipe Line 1050." The calculation derived the minimum acceptable wall thickness for operability at 0.026 inches. The inspectors reviewed the UT Report (No. 02UT033), which concluded that the pipe was operable, based upon the lowest indicated thickness of 0.045 inches.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope (IP 711117B)

The inspectors reviewed selected risk-significant permanent design change packages (DCPs) to verify that the design bases, licensing bases, and performance capability of risk significant systems, structures, and components (SSCs) had not been degraded through modification. A listing of the plant modifications and other associated material reviewed is provided in Attachment A.

The inspectors evaluated DCPs to verify that the modifications did not degrade system availability, reliability, or functional capability of the related SSCs. Modifications were selected based on risk significance and included SSCs for the event initiator, barrier integrity and mitigating systems cornerstones. The inspectors reviewed several SSC attributes including: safety classification; energy requirements; interfacing and supporting systems; materials and replacement component compatibility; component seismic qualification; instrument set-points; uncertainty calculations; electrical coordination studies; electrical loads analysis; and equipment environmental qualification. Design assumptions were reviewed to verify that they were technically appropriate and consistent with the Updated Final Safety Analysis Report (UFSAR). For each modification, the 10 CFR 50.59 screenings or evaluations were reviewed, as described in section 1R02 of this report. Post modification testing was reviewed to verify proper installation and SSC operability. Inspectors verified that procedures, design basis documents (DBDs), and the FSAR were properly updated with revised design information and operating guidance. The inspectors also verified that the as-built configuration was accurately reflected in the design drawings.

The plant modifications review included walkdowns of selected plant systems and components, interviews with plant staff, and the review of applicable documents including: procedures, engineering calculations, modification packages, safety evaluations, site drawings, corrective action documents, Technical Specifications (TS), and system DBDs.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope (71111.19)

The inspectors reviewed post-maintenance test (PMT) procedures and associated testing activities to assess whether: 1) the effect of testing had been adequately addressed by control room personnel; 2) testing was adequate for the maintenance performed; 3) acceptance criteria were clear and adequately demonstrated operational readiness, consistent with design and licensing documents; 4) test instrumentation had current calibrations, range, and accuracy for the application; and, 5) test equipment was removed following testing. The following PMT activities were observed and evaluated:

- During the scheduled 31 ABFP functional test on October 25, 2002, the pump motor power supply breaker tripped on over-current shortly after the pump was started from the control room. CR No. IP3-2002-04351 was initiated to document this failure. The inspectors observed troubleshooting of the motor and circuit breaker, which included electrical tests of the motor and its power supply cables. After no apparent cause for the trip was identified, the licensee replaced the breaker with a spare, and planned to conduct a more detailed failure analysis in the maintenance shop. The inspectors witnessed the subsequent test of the ABFP (3PT-Q120A) to assure satisfactory breaker and pump performance.

- On December 23, 2002, the licensee replaced the 31 battery charger's alternating current (AC) voltmeter. The inspectors reviewed the adequacy of the work request used to place the battery charger back in service after the replacement and observed the performance of the retest. The first retest failed when the AC input breaker immediately tripped upon closing. The inspectors reviewed the evaluation conducted by maintenance personnel, which determined that the breaker was not forcefully latched by the operator. The battery charger was then restarted with no further problems.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope (71111.22)

The inspectors observed portions of the below listed surveillance tests and reviewed the test procedures to assess whether: 1) the test pre-conditioned any of the components; 2) the scheduling and conduct of the tests were consistent with plant conditions; 3) the acceptance criteria demonstrated system operability, consistent with design requirements and the licensing basis; 4) the test equipment range and accuracy were adequate for the application, and the test equipment was properly calibrated; 5) the test was performed in the proper sequence; and, 6) the affected system(s) was properly restored to the correct configuration following the test.

- 3PT-Q116C: "33 Safety Injection (SI) Pump Functional Test;" performed on October 4.

  During this test, the inspectors noted that the safety injection (SI) component cooling water (CCW) pump suction and discharge pressures were approximately 50 psig greater than those recorded on the previous quarterly surveillance test. During a review of the system pressure data from surveillance tests over the past two years, the inspectors found that the data from the previous surveillance was inconsistent with the other tests. The inspectors reviewed CR-IP3-2002-04094, which the licensee generated to address this problem. The inspectors discussed the CR with the cognizant engineers who had determined that the most likely cause for the lower than expected pressure was a partial blockage of the system by foreign material, which had subsequently passed through the system.

  While evaluating the material condition of the other two SI pumps, the inspectors noted that two carbon steel spacers on the shaft seal assembly of 31 SI pump were degraded by boric acid that had leaked out of the seal. The SI system engineer generated CR-IP3-2002-4115 to evaluate this problem. It was determined that the spacers were only required for initial shaft gland alignment following seal replacement, and the carbon steel spacers were subsequently removed. The licensee initiated a change to the maintenance procedure used for seal replacements to prevent this condition in the future.

- 3PT-Q120B: “32 Auxiliary Boiler Feedwater Pump Test;” performed on November 25.

- 3PT-Q129, Service Water System Alignment Verification, performed on December 12.

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications

a. Inspection Scope (71111.23)

On December 27, 2002, the inspectors reviewed the engineering documentation for Temporary Modification (TM) No. 02-3-069: “Provide Alternate EDG Cooler Service Water Flow Path for 33 EDG.” The TM was installed to allow continued EDG availability when a service water valve (vacuum breaker SWN-69) downstream from the EDG coolers was scheduled for repair. The inspectors reviewed the temporary modification design, the engineering design verification, and the 10 CFR 50.59 screening against design bases documents to ensure the modification did not adversely affect EDG operability or availability. The inspectors also walked down the temporary modification and verified that the installation was in accordance with the modification documents, ensured the modification was properly tagged, and verified the adequacy of the installation documentation (WR#IP3-02-16984).

The inspectors reviewed the post-installation testing to ensure it was satisfactory to verify the impact of the modification on the EDG and service water systems. The inspectors also reviewed the planned testing for after removal of the temporary modification.

b. Findings

No findings of significance were identified

3. SAFEGUARDS

Cornerstone: Physical Protection (PP)

3PP1 Response to Contingency Events

a. Inspection Scope (71130.03)

The inspectors reviewed the status of security operations and assessed licensee implementation of the protective measures in place as a result of the current, elevated threat environment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification

RETS/ODCM Radiological Effluent Occurrences

a. Inspection Scope (71151)

The inspectors reviewed the following documents to ensure the licensee met all requirements of the performance indicator (PI) from the first quarter 2001 to the second quarter 2002 (6 quarters):

– monthly projected dose assessment results due to radioactive liquid and gaseous effluent releases;
– quarterly projected dose assessment results due to radioactive liquid and gaseous effluent releases;
– condition reports and corrective actions;
– associated procedures.

The inspectors also performed an independent verification of the licensee's capability for calculating projected doses to the public resulting from discharges of radioactive liquid, gases, and particulate using the licensee's meteorological monitoring data. The licensee used its computer code for radioactive gas releases. The NRC used the NRC PC-DOSE computer code. The comparison results were evaluated.

The inspectors also reviewed the data submitted to the NRC for the following PIs and verified that the submitted data was consistent with plant records for the second and third quarters of 2002.

– Safety System Functional Failures
– Safety System Unavailability

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

a. Inspection Scope (71152)

The inspectors reviewed corrective action documents associated with plant modifications to ensure that the licensee was identifying, evaluating, and correcting problems and that the corrective actions were appropriate. The inspectors also reviewed audits and self-assessments related to 10 CFR 50.59 and plant modification activities. A listing of the condition reports and associated documents reviewed is provided in Attachment A to this report.

The inspectors reviewed a sample of CRs documenting problems with the safety evaluation process. The reviewed included CR-IP3-2001-03177, which involved potential weaknesses in the 10 CFR 50.59 evaluations of backup spent fuel pool cooling and the potential operation of the essential service water (ESW) system outside its design basis. Additionally, the inspectors reviewed CR-IP3-2001-03023, which involved the 10 CFR 50.59 evaluation regarding the inspection and repairs of an EDG underground fuel oil tank. The inspectors also reviewed CR-IP3-2001-01005, which identified inaccuracies in the 10 CFR 50.59 preparers and screeners qualification matrix. The inspectors reviewed the corrective actions associated with all of the selected CRs.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up

a. Inspection Scope (71153)

- On November 15, 2002, the reactor automatically tripped following a main generator load reject and turbine trip caused by a catastrophic fault in 345KV output breaker No. 3. Shortly following shutdown of the plant and stabilization in Mode 3, the licensee formed a Post Transient Review Group (PTRG), which conducted interviews of all control room operators who responded to the event, and gathered all the pertinent plant system data in order to analyze the plant's response. The inspectors reviewed PTRG Report No. 02-02, which confirmed that all systems responded within their design limits. The inspectors also reviewed the licensees root cause analysis of the event. It was determined that poor maintenance practices during a preventive maintenance overhaul in 2001 resulted in contact misalignment inside the breaker which eventually led to the failure.

  The inspectors also reviewed the licensee's planned corrective actions documented in CR-IP3-2002-04550. The inspectors observed portions of the contact re-alignment (WR-IP3-0101608), and discussed development of improved procedures with maintenance personnel involved with the work. The licensee completed the contact re-alignment on breaker No. 1 on November 21, 2002, prior to bringing the plant back on line, and initiated a monitoring program for breaker No. 1 during the power ascension.

- On December 7, 2002, a fire occurred in lagging on the 32 main boiler feed pump (MBFP). The fire was extinguished by the fire brigade in less than 15 minutes. Due to its short duration, and the fact that the fire was not in an area defined in Section 8.0 of the Emergency Action Level Technical Basis, an Unusual Event was not declared. Inspectors evaluated the areas on and around the MBFP for damage, and interviewed fire brigade members and the Fire Protection Supervisor to assess fire brigade response to the fire. The inspectors also reviewed report IP-PCE-02-215, which critiqued the fire brigade response. The licensee determined that the cause of the fire was oil leaking from the turbine shaft bearing casing, which had accumulated underneath lagging, and ignited from direct contact with the hot turbine casing. The inspectors evaluated the licensee's extent-of-condition review and corrective actions to prevent recurrence.

- On December 11, 2002, hot spots were discovered in 345KV disconnect switch 4B in the Buchanan switchyard, while the switchyard was aligned to deliver all plant power to the grid through the switch. Since an alternate path was not available at the time, the hot spot represented a potential plant trip risk. Entergy reduced power to reverse the temperature rise on the disconnect. The inspectors observed operators conduct the power reduction to 70% and evaluated operators effectiveness of communications and use of procedures. On December 12, the licensee further reduced plant power to approximately 60%, and again to approximately 48% on December 13, due to a hot spot on disconnect switch F3-5. Throughout this period and during the returned to 100% power on December

16, the inspectors observed control room activities observed maintenance activities in the switchyard, and monitored plant meetings and Entergy management decision-making with respect to this issue.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting Summary

On January 20, 2003, the inspectors presented the inspection results to Mr. Chris Schwarz and Entergy staff members who acknowledged the inspection results presented. The inspectors verified with Entergy personnel that no materials evaluated during the inspection were considered proprietary.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

a. Key Points of Contact

R. Barrett	Vice President, Operations - IP3
J. Bencivenga,	Design Engineer
J. Boccio,	General Supervisor, I&C
R. Cavalieri	Site Planning and Outage Services Manager
R. Christman	Assistant Operations Manager, Operations Staff
J. Comiotes	Director, Nuclear Safety Assurance
J. DeRoy	General Manager of Plant Operations
R. Deschamps	Radiation Protection Manager
M. Devlin	Work Control Superintendent
R. Discensi	Technical Support Manager
J. Donnelly	Corrective Actions and Assessment Manager
P. Faughnan	Operations Shift Manager
M. Gillman	Operations Manager
J. Kelly,	Director, Nuclear Safety Assurance
R. LaVera	Senior Radiological Engineer
J. LePere	Waste Management General Supervisor
J. McCann	Licensing Manager
R. Milici	Senior Electrical Engineer
E. O'Donnell	Acting Operations Manager
J. Perrotta	Quality Assurance Manager
S. Petrosi,	Design Engineering, Manager
S. Rokerya,	Licensing
R. Schimpf,	Senior I&C Engineer
M. Smith	Director, Engineering - IP3
N. Srivatsan,	Senior I&C Engineer
D. Thompson	Security Manager
A. Vitale	Maintenance Manager
J. Wheeler	Training Manager
F. Weinert,	Senior Electrical Engineer
B. Young,	Senior Mechanical Engineer

b. List of Items Opened, Closed, and Discussed

None

c. List of Documents Reviewed

Permanent Plant Modifications (Design Changes and the 50.59 evaluations)

97-03-439	Replace Foxboro Controllers with NUS Controllers
00-3-093	Replacement of 6.9 kV Undervoltage Relays 27-1A Through 27-4A
01-3-022	Instrument Bus 34 Inverter Replacement
00-3-005	Install auto-closure feature on MF MOVs BFD-5 1-4 and BFB 90 1-4
00-03-049	Eliminate Vent Path from the CB into PAB if VS-PCV-1190 fails
00-3-008	Install tornado missile barrier and access points and internal pipe mechanical sealed in SW line 408.
00-3-018	Replacement of Station Battery 31 and Station Battery 32
01-049	CCR Recorder upgrade
00-076	Pressurizer missile shield

10 CFR 50.59 Safety Evaluations

DCP 00-3-063	Replacement of Westinghouse Type BF Relays and Re-Powering of CCR Racks
EVL 01-3-024	Evaluation of Bus 6A Outage Temporary Power for Fuel Storage Building Exhaust Fan
NSE 00-096,	Live Transfer of 480 V Buses 312 and 313
NSE 01-3-008	Temporary Modification to Install Power Panel 31 and 32 Pig Tails
NSE 01-03-011	Evaluation of Bus 6A Outage Temporary Power
EVL 00-3-010	Vacuum refill of the RCS
EVL 01-3-027	Remove OTDT OPDT Runbacks
NSE No. 00-03-095	Opening SWN-35-1 and SWN-35-2 Beyond Maximum Open Position Limits When RCS is less than 350 deg. F.
NSC01-3-018	Evaluate Required actions to Insure VC Sump Monitor is Adequate to Support RCS Leakage Detection.
NSE 01-03-019	Alignment of Circulating Water Pumps to the Essential Service Water Header.

10 CFR 50.59 Safety Screens

DCP 97-3-367, Rev. 0,	Delete NIS Rod Drop Turbine Runback
DC 97-03-439, Rev. 0,	Replace Foxboro Controllers with NUS Controllers
DCP 01-3-026, Rev. 1,	IP3 Control Room Recorders Upgrade (WR# 01-00252-01)
DCP 00-3009, Rev. 0,	No. 36 Feedwater Heater Vent Piping and Header Replacement.
DCP 02-3-054, Rev. 0,	Installation of Additional Check Valve in IVSWS Header to the SGDB/SGBD Sampling Lines.

Design References and Calculations

IP3-ECCF-683, Rev. 0,	Evaluation of The Replacing Foxboro Controllers with NUS Controllers
IP3-ECCF-919, Rev. 0,	Evaluation of The Impact of Replacing The Instrument Bus 34 Westinghouse Static Inverter with a Solid state Controls Incorporated Static Inverter
6461.006F-WCCPPS, Rev2,	WCCPPS Orifice sizing
00-086, dated 10/10/00	SW Hydraulic Analysis
6604.266-8-sw-021 Rev 6	SW Hydraulic Analysis
IP3-CALC-STR-03242, Rev. 0	Evaluation of 3" Steel Plate on top of Pressurizer Bio Shield Wall.

Procedures

AP 66, Rev 3	Process Applicability Screening
AP-8.2, Rev. 10,	Deviation and Event Analysis
ENN-LI-101, Rev. 1,	10CFR50.59 Review Process
ENN-LI-102, Rev. 2,	Corrective Action Process
MCM-1, Rev. 6,	Design Changes
MCM-1, Rev. 8,	Design Changes
MCM-4, Rev. 9,	Modification Control Manual
MCM-4.2, Rev. 0,	Modification Control Manual 10CFR50.59 Evaluation
MCM -19 Rev 4	Engineering Closure

Corrective Action Documents

Condition Report Summary List, 3/2001 - 10/2002

CR-IP3-2001-01005
CR-IP3-2001-03023
CR-IP3-2001-03177
CR-IP3-2001-03360
CR-IP3-2002-04287
CR-IP3-2002-03013
CR-IP3-2001-03116

ACTS-01-54967
ACTS-01-55356
ACTS-01-57839
ACTS-01-57827
ACTS-01-58004
ACTS-01-58204
ACTS-01-59950
ACTS-01-59951
ACTS-02-60920
ACTS-02-60921
ACTS 01-56645

Work Requests

94-00707-00
94-00707-01
94-00707-85
00-04678-18
99-05022-04

Purchase Orders

PO No. S 97 03991
PO No. 4500512985

Drawings

9321-F-33853, Rev. 16, Electrical Distribution and Transmission System
A201640, Rev 16, As Built per 00-3-076 (Containment BioShield Walls)

Self-Assessments and QA Audits

A02-02 I, QA Audit Report, Design Control
First Quarter 2002 (1Q02) Integrated Self-Assessment/Trend Report, April 29, 2002
Second Quarter 2002 (2Q02) Integrated Self-Assessment/Trend Report, July 30,2002

Regulatory References

Indian Point 3 Nuclear Power Plant, Final Safety Analysis Report Update
Indian Point 3 Technical Specifications

Other

Technical Specification Amendment No. 209 package, License No. DPR-64.
NRC SER by NRR for Amendment 209.
Design Basis Document Change Notice PCN-DBD-307-18, Rev. 2.
Design Change Walkdown Report, Dated 10/02/01.
Plant Equipment Data Base for Batteries 31 and 32.
Load Profile Tests 3PT-R156A, Rev. 7, dated 1/15/02 for Battery 31, and 1/25/02 for Battery 32

d. List of Acronyms

AC	alternating current
A/C	air conditioning
ABFP	auxiliary boiler feedwater pump
ARP	alarm response procedure
CFR	Code of Federal Regulations
COL	check-off list
CR	condition report
CVCS	chemical and volume control system
DBD	Design Basis Documents
DCP	design change package
EDG	emergency diesel generator
ESW	essential service water
FCU	fan cooler unit
FP	fire protection
FSAR	Final Safety Analysis Report (Updated)
I&C	Instrument and Control
IACC	instrument air closed cooling
IP2	Indian Point 2
IP3	Indian Point 3
IPEC	Indian Point Energy Center
KV	kilo volts
MBFP	main boiler feedwater pump
NI	nuclear instrument
NRC	Nuclear Regulatory Commission
NSE	Nuclear Safety Evaluation
OD	operability determination
ONOP	off-normal operating procedure
PAB	primary auxiliary building
PFP	Pre-Fire Plan
PI	performance indicator
PM	preventive maintenance
PMT	post-maintenance test
ppm	parts per million
PTRG	Post Transient Review Group
QA	Quality Assurance
RCS	reactor coolant system
SAT	station auxiliary transformer
SDP	Significance Determination Process
SI	safety injection
SOP	system operating procedure
SSC	structures, systems, and components
SW	service water
TM	temporary modification
TS	Technical Specifications
UT	ultrasonic test
WPO	White Plains Office
WR	work request