September 30, 2001

EA 01-255

Mr. Fred Dacimo
Vice President - Operations
Entergy Nuclear Operations, Inc.
Indian Point 2 Station
Broadway and Bleakley Avenue
Buchanan, NY 10511

SUBJECT: INDIAN POINT 2 - NRC INSPECTION REPORT 50-247/01-08

Dear Mr. Dacimo:

On August 18, 2001, the NRC completed an inspection at the Indian Point 2 nuclear power plant. The enclosed report presents the results of that inspection. The results were discussed on August 24, 2001, with you and 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. The inspection also reviewed major design engineering projects and a white performance indicator for reactor trip frequency.

NRC findings this period confirmed safe plant operation. We also noted three issues of very low safety significance: 1) a failure to fully consider plant risk with an inoperable direct trip function to the main generator, 2) a less than rigorous operability determination associated with the boric acid system, and 3) poor communications with off-site electrical distribution personnel which resulted in untimely detection of degraded equipment related to main turbine trip functions.

Based on the results of this inspection, two violations of NRC requirements were identified regarding the failure to fully consider risk associated with on-going pilot wire degradation and the failure to correct repetitive post maintenance test failures for the 23 emergency diesel generator. However, because of the very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as Non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these Non-cited violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Indian Point 2 Nuclear Power Plant.

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/NRC/ADAMS/index.html (the Public Electronic Reading Room). Should you have any questions regarding this report, please contact Mr. Peter Eselgroth at 610-337-5234.

Sincerely,

/RA/

Brian E. Holian, Deputy Director
Division of Reactor Projects

Docket No.50-247
License No. DPR-26

Enclosure: Inspection Report 50-247/01-08

Attachment 1 - Supplemental Information

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M. Slobodien, Director Emergency Planning
L. Temple, Plant Manager
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P. Eddy, Electric Division, Department of Public Service, State of New York
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W. Flynn, President, New York State Energy Research and Development Authority
J. Spath, Program Director, New York State Energy Research and Development Authority
The Honorable Sandra Galef, NYS Assembly
County Clerk, Westchester County Legislature
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-247
License No.	DPR-26
Report No.	50-247/01-08
Licensee:	Entergy Nuclear Operations, Inc..
Facility:	Indian Point 2 Nuclear Power Plant
Location:	Buchanan, New York 10511
Dates:	July 1 - August 18, 2001
Inspectors:	William Raymond, Senior Resident Inspector Peter Habighorst, Resident Inspector Gregory Cranston, Reactor Inspector, DRS Ross Telson, Resident Inspector, Sequoyah Larry Scholl, Senior Reactor Engineer, DRS Douglas Dempsey, Reactor Inspector, DRS John McFadden, Health Physicist, DRS
Approved by:	Peter W. Eselgroth, Chief Projects Branch 2 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000247-01-08, on 07/01 - 08/18/2001, Entergy Nuclear Operations, Inc.; Indian Point 2 Nuclear Power Plant. Maintenance, Operability Evaluations, and Cross-cutting Issues.

The inspection was conducted by resident and region-based inspectors. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process (SDP). This inspection identified all green or no color issues. The “no color” significance level indicates that the IMC 0609 “Significance Determination Process” does not apply to these findings.

Cornerstone: Mitigating Systems

Green. The licensee failed to fully consider ongoing plant risk with an inoperable main turbine direct trip function between July 21 and August 7, 2001. This issue had a credible impact on safety because of the lack of automatic 6.9 kV bus transfer from the unit auxiliary transformer to the station auxiliary transformer following a postulated 345 kV system fault. On July 22, 2001, the 23 emergency diesel generator was removed from service for planned maintenance. This activity qualitatively would have increased plant risk given a transient on the 345 kV system and short-term unavailability of offsite power to safeguards buses 2A and 3A with no emergency power to safeguards bus 6A during the planned maintenance. Operator actions would be necessary to restore power to two of four safeguards buses. Qualitative assessments were not performed until the inspector discussed this observation with the licensee on August 7, 2001. Additionally, risk associated with the inoperable trip should have been incorporated into maintenance restrictions on certain safety equipment. This issue was evaluated in the Significance Determination Process and found to have very low safety significance. The failure to consider plant risk for an inoperable main turbine direct trip from a 345 kV fault is contrary to 10 CFR 50.65(a)(4). This violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000 (65 FR 25368)

Green. An initial licensee operability evaluation was incomplete in that it failed to consider the impact on net positive suction head (NPSH) for the 22 boric acid transfer pump when the boric acid tank temperature reached 209 degrees Fahrenheit. This issue was evaluated in the Significance Determination Process and found to have very low safety significance.

Cross-cutting Issues

Green. Poor communications between plant operations staff and off-site electrical distribution personnel resulted in the untimely recognition of a degraded main turbine trip function that provided redundant protection from a fault in the offsite 345 kV system. Specifically, circuit troubleshooting in July 2001 identified a 345 kV pilot wire protection trip that was degraded since January 3, 2001. The licensee also identified poor quality drawings for offsite protection equipment and poor configuration control (a spare 125 volt DC breaker was open instead of closed as required). Although the drawings and configuration control were not maintained by Indian Point Unit 2 personnel, they did impact the function of the electrical system as described in the UFSAR section 8.1.1 and 14.1.6.2. This issue was evaluated in the Significance Determination Process and found to have very low safety significance.

Summary of Findings (cont'd)

No Color. The licensee did not identify a condition adverse to quality evident in the repeated failures of a post-maintenance test (PMT) associated with the 23 emergency diesel generator (EDG). Following governor oil replacement in July 2001, the PMT was to perform the monthly surveillance PT-M21C, “Emergency Diesel Generator 23 Load Test.” The procedure requires the EDG to be loaded to the 30 minute rating of 2300 kilowatts (kW). During the PMT, the 23 EDG could not achieve 2,300 kW, but was loaded to 2250 kW on July 25 and 2275 kW on July 26, 2001. The inability to reach desired loading was related to reaching terminal voltage limits when the EDG was tested with the generator operated in parallel with the offsite electrical grid. The licensee concluded that the inability to reach the desired load was an artifact of the test methodology and that the EDG would be able to reach the desired load under isochronous (loss of offsite power) conditions. Thus, the operability determination demonstrated the EDG could reach full load. Although EDG operability questions were addressed by this operability determination, the inspector was concerned with lack of progress in addressing this issue on previous occasions since six condition reports in the last three years documented EDGs not obtaining the desired loading due to offsite grid conditions (CR 199810268, 200003415, 200003494, 200003541, 200004426, 200004462). Previous corrective actions were not effective at resolving this testing deficiency. The failure to initiate a condition report for a condition adverse to quality (failure of a PMT for the EDG) is considered a violation of 10 CFR 50 Appendix B, criterion XVI. This violation is being treated as a Non-Cited violation, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000 (65 FR 25388).

TABLE OF CONTENTS

Report Details

SUMMARY OF PLANT STATUS

The plant operated at full power during the period until August 15, 2001, when plant load was reduced to 70% full power to repair a leak on the 22 main boiler feedwater pump. The plant returned to full power operation on August 17, 2001.

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

1R01 Adverse Weather Protection

a. Inspection Scope (71111.01)

The purpose of this inspection was to review licensee actions in response to a excessive ambient temperatures and severe thunderstorms between August 6-10, 2001 The inspector reviewed licensee actions to monitor plant equipment, assess plant risk and implement compensatory measures particularly when gas turbine power supplies became degraded. The following references were used for this review:

- Abnormal Operating Instruction (AOI) 28.0.7, Hurricane/Tornado/High Wind/Severe Thunderstorm, Revision 11
- AOI 24.1, Service Water Malfunction, Revision 9
- AOI 11.2, Loss of Technical Support Center (TSC) Computer Room Air Conditioning, Revision 0

The inspector reviewed licensee actions to assess and address degraded conditions as documented in the following condition reports: CR 200107747, 200107760, 200107787, 200107789, 200107790, 200107825, and 200107833. The condition reports were associated with adverse weather and risk significant gas turbine power supplies.

b. Issues and Findings

No significant findings were identified.

1R04 Equipment Alignment

.1 Complete System Walkdown

a. Inspection Scope (71111.04S)

The inspection scope involved a system walkdown of accessible containment isolation valves. The inspector selected the containment isolation system based upon its importance to plant safety and risk as referenced in NRC manual chapter 0609 Appendix H. The regulatory requirements for an operable containment isolation system are identified in Technical Specification Section 3.6. Licensee procedures used during the walkdown to confirm appropriate alignment included:

- Check off list (COL) 10.6.2, Containment Integrity
- COL 10.0, Locked Safeguards Valves
- Emergency Operating Procedure E-0, Reactor Trip/Safety Injection (Attach. 1)
- System Operating Procedure 10.6.4, Operation/Control of Non-automatic Containment Isolation Valves
- Abnormal Operating Instruction 10.6.2, Loss of Containment Integrity

The inspector reviewed a sampling of licensee commitments associated with the containment isolation valve system. The specific commitments verified by the inspector included:

- 10 CFR 21 report on Main Steam Check Valve Packing Adjustments
- Licensee Event Report (LER) 50-247/84-10 Excess service water valve leak
- LER 50-247/98-21, Failure of automatic containment isolation valve
- Technical Specification Amendment 193
- IE Bulletin 80-06 Engineered Safety Feature Reset Controls

The inspector noted there were no outstanding temporary facility changes, operator work arounds, and control room deficiencies associated with the containment isolation system. The inspection verified that the licensee properly identified deficiencies associated with the containment isolation valve system (reference CR 200006521, 200107606, 200107596, 200107586, and 200107606). The inspector reviewed selected corrective actions associated with containment isolation valve design basis document (DBD) open items. The following items were reviewed:

- PLI-CISS-006, Isolation Valve Seal Water (IVSW)Tank Pressure calculation
- PLI-CISS-007, Minimum Size of IVSW Nitrogen Supply Bank
- PLI-CISS-011, Leakage Limits for Weld Channel Containment Pressure System

b. Issues and Findings

No significant findings were identified.

.2 Partial System Walkdowns

a. Inspection Scope (71111.04)

The partial system reviews were conducted on the isolation valve seal water (IVSW) and the auxiliary feedwater (AFW) systems to verify support systems and component alignments were proper. The inspector evaluated the impact on system function from outstanding equipment deficiencies and area housekeeping issues.

For the IVSW system the inspector reviewed the following documents:

- System Operating Procedure (SOP) 10.4.1, Isolation Valve Seal Water System Operations
- Check off list (COL) 10.4.1, Isolation Valve Seal Water System

The inspector reviewed the temporary facility change log, operator work around list, and open corrective actions from condition reports in the last two years to identify any deficiencies that may impact isolation valve seal water operability.

On August 13, 2001, the inspector performed a partial walkdown of the 21 and 23 motor driven auxiliary feedwater (AFW) pumps and associated normal and emergency power supplies. The licensee was preparing to conduct a quarterly surveillance test, PT-Q34, 22 Auxiliary Feed Pump Test.

b. Issues and Findings

No significant findings were identified.

The inspector identified that neither the open nor closed position indication lights were lit to indicate valve position for the following solenoid valves: SOV-3512, seal water/N_2 isolation valve; SOV-3515, seal water/N_2 isolation valve; SOV-7864, IVSWS flow control; and, SOV-5024, H_2 O_2 analyzer sample return to VC. The inspector referred these problems to the licensee. The licensee generated a condition report (CR) and took appropriate corrective actions.

1R05 Fire Protection

.1 Fire Zone Tours

a. Inspection Scope (71111.05Q)

The inspector toured the areas important to plant safety and risk based upon a review of Section 4.0, "Internal Fires Analysis," and Table 4.6-2, "Summary of Core Damage Frequency Contributions from Fire Zones," in The licensee's Individual Plant Examination for External Events. The inspector reviewed the plant areas identified below to assess the material condition and operational lineup of the fire protection systems, the control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. The areas included:

- Fire Zone 56A, 22 Main Transformer
- Fire Zone 25, 23 Battery Room
- Fire Zone 55, Radiation Monitor Building
- Fire Zone 66A, Service Water Valve and Strainer Pit
- Fire Zone 60A, Auxiliary Feedwater Pump Building, 32 ft elevation
- Fire Zone 18A, Primary Auxiliary Building, 15 ft, 42 ft and 59 ft elevations

Reference material consulted by the inspector included the licensee's Fire Protection Implementation Plan, Pre-Fire Plan, and station administrative orders (SAO)-700, Fire Protection and Prevention Policy, SAO-701, Control of Combustibles and Transient Fire Load, SAO-703, Fire Protection Impairment Criteria and Surveillance, and PI-V17, Penetration Fire Barrier Seal Inspections. The regulatory basis for the inspection included Technical Specification 6.8.1.e and license condition 2.K.

The inspector verified the licensee was identifying issues within the areas reviewed at the appropriate threshold and addressing them in the corrective action program, and that corrective actions were appropriate (reference Condition Report 200009835).

b. Issues and Findings

No significant findings were identified.

A minor material condition issue was identified by the inspector that did not impact fire protection, mitigation, or initiation. The deficiency was entered into the corrective action program as CR 200107160.

1R06 Flood Protection Measures

a. Inspection Scope (71111.06)

The inspector reviewed and toured areas containing equipment used to mitigate the impact of flooding on the 15 foot elevation of the Unit 2 turbine building and the primary auxiliary building, and the 18 foot elevation of the auxiliary feedwater building.

The plant areas selected contained risk significant equipment based on the Individual Plant Examination of External Events (IPEEE) Section 5.0. Specifically, a major turbine building flood is considered the second highest contributor to plant risk from an internal plant flood. The risk significance is dominated by a non-recoverable loss of normal power to the 480 volt safeguards buses. The inspection determined whether procedures were adequate and mitigation systems were operable pursuant to Technical Specification requirements.

The inspector reviewed applicable licensee procedures and surveillance procedures, which included actions to mitigate the effects of flooding and tours to verify operability of mitigating equipment. The procedures reviewed included:

- Abnormal Operating Instruction (AOI) 28.0.4, Plant Flooding - Conventional Side
- AOI 28.0.6, Nuclear Side (Outside Containment) Flooding
- PT-M55, Fire Doors

The inspector reviewed sections 1.11.8 and 8.1.1 of the Updated Final Safety Analysis report. The inspector also reviewed past licensing actions associated with internal flooding that included:

- NRC Safety Evaluation Report (12/18/80), Susceptibility of Safety-related Systems to Flooding from Failure of Non-Category 1 Systems For IP2
- Licensee Letter to NRC (7/14/1980), External Flooding due to Failure of Non-Class I Seismic Equipment

A number of condition reports generated by the licensee concerned internal flood issues (200100878, 200108024, and 200108027). The inspector reviewed the CRs to determine whether issues were being properly documented and assessed.

b. Issues and Findings

The inspector observed the flood door flaps located in the auxiliary feedwater pump room and the lower elevation of the primary auxiliary building could be hard to operate due to mechanical interference. The function of the door flaps is to swing open to direct flood water away from the auxiliary feedwater pumps and the residual heat removal pumps. This mitigation strategy is credited in IPEEE Section 5.0. The licensee documented this observation in CR 200108027.

The inspector identified a difference between licensee commitments and the analysis in the IPEEE for a major flood within the turbine building. The NRC safety evaluation report (SER) concludes that design features and operating procedures provide assurance that the plant can be safely shutdown in the event of flooding outside containment from a non-seismic component or pipe. Further, the SER states that a potential exists for flooding in the 480 volt switchgear given a postulated circulating water pipe break. One design feature committed to by the licensee in the July 14, 1980, letter was an independent, control room alarm for the unit 1 condenser pit to provide early indication of a major flood within the unit 2 turbine building. This design feature is credited and operator actions are taken in response to this alarm in AOI 28.0.4. The inspector identified that the alarm would only function after a critical flood height is reached which in turn could impact the 480 volt safeguards buses. The IPEEE concludes that a major flood in the turbine building (circulating water pipe or expansion joint failure) will stop when the 6.9 kV switchgear becomes flooded. Further, the IPEEE documents that a potential flood of the 480 volt switchgear room (located on the same elevation as 6.9 kV switchgear) is not credible since flood waters would have to pass through two normally closed doors that have an intervening floor drain. The inspector noted the doors are not sealed against leakage and questioned the licensee's basis for the conclusion that the 480 switchgear would not be impacted by a postulated flood. The licensee documented this potential discrepancy in condition report 200108024.

Both issues described above are considered unresolved pending further NRC review to determine whether 1) operator actions within AOI 28.0.4 are adequate to mitigate a flood in the turbine building, and 2) the door flaps are functional to mitigating a postulated flood within the primary auxiliary building and auxiliary feed pump building. **(UNR 05000247/2001-08-01)**

1R12 Maintenance Rule Implementation

a. Inspection Scope (71111.12)

The inspector reviewed risk significant equipment problems that occurred during the 1st quarter of 2001 on the emergency diesel generator (EDG) support systems and the chemical and volume control system (CVCS). The inspector reviewed licensee follow-up actions to assess the effectiveness of maintenance activities. Issues selected for review included licensee identification of any functional failures, maintenance preventable functional failures, and repetitive failures as well as problem identification and resolution of any maintenance related issues. The inspector also reviewed system availability, system reliability monitoring, and system engineering involvement. The licensee's Maintenance Rule background document was reviewed. The following issues were reviewed:

Report No.	Condition Description
200104753	21 EDG Lube oil strainer alarm setpoint out of specification
200103037	22 EDG fuel oil transfer pump failure to start
200103090	22 EDG fuel oil day tank level controller repeat problems
200100039	Letdown pressure control valve (PCV)-135 hunting and causing letdown flow to oscillate.
200100572	PCV-135, letdown pressure control valve, oscillates when controller is in automatic during testing.
200101024	PCV-135, letdown pressure control valve, being operated in manual due to oscillation problems when controller is in automatic during testing.
200100997	23 charging pump failed surveillance test PT-Q33C and is inoperable.
200101064	23 changing pump declared inoperable due to a failure to deliver sufficient flow per surveillance test PT-Q33C.
200101142	23 charging pump scoop tube for the fluid drive motor will not go to full minimum position.
200101247	23 changing pump speed control linkage connected at different place than for the 21 and 22 charging pumps causing 23 charging pump to run at a slower speed. PT-Q33C performed successfully following linkage correction.

b. Issues and Findings

No significant findings were identified.

The inspector noted that the problem with PCV-135 occurs only during periodic testing and is not significant enough to affect its functionality. During normal operation the valve operates properly. The inspector verified licensee corrective actions were addressed in the corrective action program (CR 200100039).

The inspector observed that the CVCS is in Maintenance Rule a(1) status for the 22 and 23 charging pumps and that the licensee identified corrective actions to restore the system to a(2) status in Condition Report 200106950. Actions have been completed to address inefficiencies in work control that impact system unavailability, and the CVCS system is scheduled to return to an a(2) status in December 2001.

1R13 Maintenance Risk Assessment and Emergent Work

a. Inspection Scope (71111.13)

The inspector evaluated the effectiveness of the risk assessments performed before maintenance was conducted and verified how the licensee managed the risk in accordance with 10 CFR 50.65(a)(4). The inspector verified that risk assessments were performed consistent with the risk models and plant conditions. The inspector verified that the licensee took the necessary steps to plan and control emergent work activities, took actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems. For activities such as troubleshooting, work planning, tagging, equipment alignment and restoration, the inspector verified that the plant was not placed in an unacceptable configuration or a condition contrary to the Technical Specifications. The inspector evaluated the effectiveness of the risk assessments associated with the following maintenance and surveillance activities:

- WO 01-22815, Transfer Switch EDD7 Failure (CR 200107796)
- WO 01-23055, Turbine Gland Steam Rupture Disc Failure
- WO 01-21915, 24 Battery Ground Search (CR 200105576, OD 01-05)
- WO 01-22703, GT3 Temperature and Fuel Supply, (CR 200107736, 200107770)
- WO 01-22717, GT2 Vibration and Fuel Supply (CR 200107837, 200107770)
- WO 01-22948, 22 MBFP Discharge Leak
- WO 01-22654, 21 MBFP Suction Leak
- WO 01-22873, GT Bus Damage and Repair
- PT-Q34, 22 Auxiliary Boiler Feedwater Pump Quarterly Surveillance
- WO 01-22231, Pilot Wire Direct Trip from Buchanan Substation Circuit Troubleshooting (CR 200106874, 7301, 7697)

The inspector verified that the licensee addressed problems with maintenance risk assessment and management and emergent work control in the corrective action program (reference Condition Report 200107171, 200107195, 200107198, 200107214, 200107544, 200107820, and 200107850).

b. Issues and Findings

(Green) The licensee failed to fully consider ongoing plant risk with an inoperable direct trip function (pilot wire trip) from the offsite supplies to the main turbine/generator between July 21 and August 7, 2001. The licensee discovered that the pilot wire trip for the main turbine on a loss of offsite power was inoperable (see Section 4OA2.1). This inoperability would have required the backup protection of the overspeed trip to automatically trip the main turbine. The licensee's risk model was unable to assess inoperability associated with the normal and emergency electrical power distribution system, specifically, the unavailability of the main turbine direct trip feature. Qualitative assessments were not performed until the inspector discussed this observation with the licensee on August 7, 2001. On July 22, 2001, the 23 emergency diesel generator (EDG) was removed from service for planned maintenance. This activity qualitatively would have increased plant risk given a transient on the 345 kV system and short-term unavailability of offsite power to safeguards buses 2A and 3A with no emergency power to safeguards bus 6A during the planned maintenance. If the direct trip was functioning properly offsite power would have been immediately available to buses 2A and 3A following a turbine trip without operator action.

This issue had a credible impact on safety because of the lack of automatic 6.9 kV bus transfer from the unit auxiliary transformer to the station auxiliary transformer following a postulated 345 kV fault. Operator actions would be necessary to restore either offsite or emergency power to two of four safeguards buses. Had the pilot wire trip remained operable during the period when the 23 EDG was out of service, the fast transfer would have ensured that all four safeguards busses remained powered from the offsite supply. The issue impacts the mitigation system cornerstone in that various safety related pumps would not be immediately available to operators. The actual safety significance is low per the significance determination process (SDP) based upon no affirmative response to screening questions in phase 1 of the SDP, and no 345 KV system fault existed that could have challenged mitigation equipment functions.

The failure to consider plant risk for an inoperable main turbine direct trip from a 345 kV fault is contrary to 10 CFR 50.65(a)(4). The licensee failed to consider plant risk from this condition on other scheduled maintenance activities between July 21 through August 7, 2001. This issue had low actual safety significance because no loss of offsite power occurred during this time interval. This violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000 (65 FR 25368) **(NCV 50-247/01-08-02)**

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

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

The licensee responded to conditions that required operator actions using special or abnormal procedures. The inspector observed operator performance, reviewed operator logs, reviewed plant data, evaluated procedure adherence, and verified adherence to Technical Specification limiting conditions for operation. The inspector reviewed the licensee actions for the events listed below:

- Power reduction to 70% due to 22 main boiler feedwater pump discharge nozzle steam leak on August 14, 2001 (CR 200107955)
- Loss of 13.8 kV Feeder on August 13, 2001, Abnormal Operating Instruction (AOI) 27.1.3 (CR200107908)

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

No significant findings were identified.

1R15 Operability Evaluations

.1 Evaluation of Degraded Conditions

a. Inspection Scope (71111.15)

The inspector reviewed selected operability determinations to assess the adequacy of the evaluations, the use and control of compensatory measures, compliance with the Technical Specifications, and the risk significance of the issue. The inspector used the Technical Specifications, Updated Final Safety Analysis Report, and associated Design Basis Documents as references. The specific issues reviewed included:

- CR200107908, 200108004, 13.8 kV Gas Turbine Bus Fault and Loss of 13W92
- CR200107796, EDD7: 23 EDG Automatic Transfer Switch Failure (OD 01-01)
- CR200107688, 125 VDC System 24 Power Panel Negative Ground (OD 01-05)
- CR 200106864, 200107167, 22 Boric Acid Tank Heater Failure

b. Issues and Findings

(Green) The initial operability evaluation of the 22 boric acid transfer pump with a 209 F boric acid tank temperature failed to consider the impact of elevated water temperature on net positive suction head (NPSH). The tank reached 209 F due to an immersion tank heater controller failure. The watch engineer's operability evaluation (CR 200106864) concluded that the tank was operable since the Technical Specification (TS) limit for temperature and concentration were maintained. TS 3.2.B.2 requires, in part, that the boric acid solution temperature shall be at least 145 F. The operator logs indicate that the normal range for the tank temperature is 160 - 174 F and the minimum and maximum temperature of the tank is between 155 to 200F. In response to the inspector's question, the licensee evaluated the adequacy of the boric acid transfer pump NPSH available associated with the high temperature (CR 200107167). The inspector reviewed the subsequent operability evaluation that concluded that the increase in vapor pressure resulted in a 5% loss of the useable volume in the 22 boric acid tank. Specifically, the NPSH available needed an additional 0.7 feet of head to ensure NPSH required for the pump at a solution temperature of 209 F. The inspector confirmed that the available boric acid inventory from both tanks was above the required minimum volume per TS 3.2.B.2 despite the loss of useable volume. The 21 boric acid storage tank contents were not impacted by the immersion tank heater failure on the 22 boric acid tank. The boiling point of 12.5% volume boric acid is 217 F. The lack of detail in the operability evaluation had a credible impact on safety in that emergency boration was potentially impacted by higher than expected temperatures in the boric acid tank. Emergency boration is considered part of the mitigating system cornerstone. The actual safety significance was low since the emergency boration system could have performed the intended safety function with the 22 boric acid tank at 209F.

.2 Evaluation of Core Power Distribution Anomaly (71111.15)

a. Inspection Scope

The maximum nuclear enthalpy rise hot channel factor, $F_{\Delta}H$, measured during flux map 15FC08 on June 26, 2001, was higher than expected in the fuel bundle at core location B10. Licensee's extrapolation of the measured data to a higher core burn-up predicted $F_{\Delta}H$ would exceed the Technical Specification 3.10.2 limit. Plant operation with core parameters in excess of the Technical Specifications could have a credible impact on safety by affecting the integrity of the fuel clad fission product barrier.

The purpose of the inspection was to review the core power distribution and trends for Cycle 15 to verify that nuclear peaking factors remained within the limits of the Core Operating Limits Report. The inspector reviewed the revised methodology adopted by The licensee in the analysis of incore flux data, "Revised Flux Mapping Analysis Guidelines for the Remainder of Cycle 15," as proposed in Westinghouse letter 011-G-021(CAC-01-190) to the licensee dated July 18, 2001, and the 10 CFR 50.59 Screen 01-576-00-RS dated July 23, 2001. Other references used for the inspection included:

- CR 200106456: Core Hot Channel Factor $F_{\Delta}H$ Higher Than Expected
- RFE-S-16.103, Evaluation of Flux Map Using 3D INCORE Code, June 28, 2001
- Applicability Determination 01-575-EV-00-AD, Flux Map Analysis Guidelines
- Full Core Flux Maps 15FC03, 15FC07, 15FC08
- Cycle 15 Flux Map Summary Results and Peaking Factor Trends
- 3D INCORE Computer Code Users Manual
- UFSAR Section 3.2.1.2, Core Power Distribution, and 3.2.1.3, Nuclear Evaluation
- WCAP-15416, Nuclear Parameters and Operations Package for IP2, Cycle 15

The inspector reviewed licensee evaluations regarding the higher power generated in the hottest fuel rod and the bundle in core location B10. The inferred power in B10 was derived by INCORE using the power measured in instrumented locations within a certain distance (specified in fuel rod pitches) from B10. The only instrument location fitting this specification was the bundle in core location A9. The measured neutron reaction rate in location A9 was 9.6% higher than predicted. The measured $F_{\Delta}H$ value was reported high by the INCORE program due to the influence from the fuel bundle in A9.

Fuel bundle S-77 in core location A9 was newly fabricated for use in Cycle 15 to replace twice burned fuel bundle Q-66 that was discharged early due to a leaky pin and other reasons, such as damage due to rod-to-grid fretting. The inspector reviewed licensee evaluations to eliminate potential design, fabrication, core loading and operational problems as causes for the anomalous power generation, which included a review of fuel bundle manufacturing and audit records to confirm proper enrichment, fuel bundle loading in the core, and the use of burnable absorbers and interim flow mixers.

The inspector reviewed licensee evaluations of thermocouple data to confirm the trends noted by the INCORE data. The possibility of a partial flow blockage could not be ruled out, but was deemed unlikely due to the design of the fuel bottom nozzles. A thermocouple in location A9 reads incorrectly low at 431F and could not be used to evaluate the flux-based power measurements. The remaining incore thermocouples did not show any observable trends or power anomaly.

The inspector, in consultation with the Office of Nuclear Reactor Regulation, verified the licensee provided an acceptable basis to revise the methodology used in the INCORE program to calculate peaking factors. The revised methodology slightly increased the number of fuel rod pitches used to calculate inferred power for the remainder of Cycle 15. The initial value of fuel rod pitch used in INCORE was conservative to maximize the calculated peaking factors. The actual influence on the power in any one rod can come from fissions up to several bundles away due to neutron coupling. Increasing the pitch provided a more accurate but still conservative calculation of peaking factors. When fuel rod pitch was increased, the correlated power from the fuel bundle core location D10 was included in the calculation of inferred power and hot channel factors for B10, which provided a more realistic measurement of the maximum $F_{\Delta}H$. The maximum $F_{\Delta}H$ remained below the Technical Specification limits during subsequent flux maps. Further NRC review of core power distribution is provided in Section 1R22.

b. Issues and Findings

No significant findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope (71111.19)

The inspector reviewed post-maintenance test (PMT) procedures and associated testing activities to assess whether 1) the effect of testing in the plant had been adequately addressed by control room personnel, 2) testing was adequate for 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 selected testing activities involved components that were risk significant as identified in the licensee's Individual Plant Examination. The regulatory basis for the inspection included Technical Specification 6.8.1.a. and 10 CFR 50 Appendix B criteria XIV, "Inspection, Test, and Operating Status." The following testing activities were evaluated:

- PMT for SWN-622 per WO 99-08994
- PMT-23059 for Bus 6A Breaker per WO 01-21915
- PMT-21530, 21 auxiliary boiler feedwater pump oil replacement and outboard pump packing replacement
- PMT-20173, 23 emergency diesel generator governor servo motor and oil replacement
- WO-01-22491, Control Rod Urgent Failure Alarm (Control Bank "C")

b. Issues and Findings

No significant findings were identified. A cross-cutting issue associated with problem identification and resolution was identified during the performance of PMT-20173 and is documented in Section 4OA2.

1R20 Refueling and Other Outage Activities

a. Inspection Scope (71111.20)

The inspector reviewed spent fuel cooling activities related to the Unit 2 refueling and maintenance outage to verify compliance and consistency within the technical specification, Updated Final Safety Analysis Report (UFSAR) and procedure requirements. The inspector reviewed issues involving cross-cutting issues, including problem identification and resolution. The following references were reviewed:

- System Operating Procedure (SOP) 4.3.1, Spent Fuel Pit Cooling, Rev. 18
- SOP 17.31, Refueling Operation Surveillance, Rev. 17
- UFSAR 9.3, Auxiliary Coolant System
- UFSAR 9.5, Fuel Handling System
- Technical Specification 3.8, Refueling and Fuel Storage, Section 3.8.B.4, Amendment 211
- Calculation PGI-00430-00, IP2 Spent Fuel Pool Thermal/Hydraulic Analysis for Fuel Discharge After 100 Hours Cooling Time, April 5, 2001.
- CR200006236, Inconsistency between Technical Specification change, the UFSAR and SOPs regarding delay time for full core offload to the SFP
- CR200107623, Change to UFSAR using generic, administrative 50.59

b. Findings

No significant findings were identified.

1R22 Surveillance Testing

.1 Auxiliary Feedwater Pump Surveillance

a. Inspection Scope (71111.22)

The inspector reviewed a surveillance test procedure and observed the testing activity to assess whether 1) the test preconditioned the component tested, 2) the effect of the testing was adequately evaluated in the control room, 3) the acceptance criteria demonstrated operational readiness consistent with design calculations and licensing documents, 4) the test equipment range and accuracy was adequate and the equipment was properly calibrated, 5) the test was performed in the proper sequence, 6) the test equipment was removed following testing, and 7) test discrepancies were appropriately evaluated. The surveillance observed was based upon risk significant components as identified in the licensee's Individual Plant Examination. The regulatory requirements that provided the acceptance criteria for this review were 10 CFR 50 Appendix B criterion V, "Instructions, Procedures, and Drawings," Criterion XIV, "Inspection, Test, and Operating Status," Criterion XI, "Test Control," and Technical Specification 6.8.1.a. The following test activity was reviewed:

- PT-Q34, 22 Auxiliary Feed Pump Test

b. Issues and Findings

No significant findings were identified.

.2 Routine Core Power Distribution Surveillance and Core Anomaly

a. Inspection Scope

The inspector observed selected portions of the core power distribution measurement and analyses for full core maps 15FC08 and 15FC09 to verify that core parameters remained within the limits specified in Technical Specification (TS) 3.10.2. The inspector reviewed:

- RFE-S-16.002, Power Distribution and Hot Channel Factor Determination at 99.9% power and 5587.9 MWD/MTU, and SOP 14.1, Moveable Incore Instrument System Operations, June 26, 2001 (CR 200106456)
- RFE-S-16.002, Power Distribution and Hot Channel Factor Determination at 99.9% power and 6574 MWD/MTU, and SOP 14.1, Moveable Incore Instrument System Operations, July 24, 2001

The inspector verified that, except for the maximum enthalpy rise hot channel factor ($F_{\Delta}H$), the core power distribution followed expected trends and was within limits for the total peaking factor (Fq), axial offset and quadrant power tilt. The maximum $F_{\Delta}H$ was higher than expected at 1.693, but below the limit of 1.7. The inspector verified the measured $F_{\Delta}H$ was increased by 4% to account for measurement uncertainty for comparison with the Technical Specification 3.10.2 limits.

The licensee initiated CR 200106456 to evaluate the cause for the anomalous peaking factor, and revised the analysis of the incore data by increasing a parameter (rod pitch) in the 3D INCORE code (see Section 1R15.2.a above). The inspector verified that the results of core flux map 15FC09 on July 24, 2001 showed that $F_{\Delta}H$ was well below the Technical Specification limit at 1.63. The inspector also verified the licensee was performing data comparisons using the previous rod pitch for benchmarking. The licensee review of core power distribution and core parameters continued at the end of the inspection period.

b. Issues and Findings

No significant findings were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope (71111.23A)

The inspector reviewed the temporary facility changes (TFCs) and associated safety evaluations listed below to verify the facility changes did not impact safety system operability and the license requirements, and did not violate 10 CFR 50.59. The inspector verified the activities were completed in accordance with The licensee's controls for installation. The following TFCs were reviewed:

- 2001-072: Bus 6A Breaker Relay 13BX Removal (SE 01-0647-TM-00-AD)
- 2001-075: 24 Bus Ground Monitoring (SE 01-0649-TM-00-RS)
- 2001-067: Thermocouple H5 Removed From Scan (SE 01-0603-TM-00-AD)

b. Issues and Findings

No significant findings were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control To Radiologically Significant Areas

a. Inspection Scope (71121.01)

The inspector reviewed radiological work activities and practices and procedural implementation during observations and tours of the facilities. The inspector reviewed procedures, records, and other program documents to evaluate the effectiveness of the licensee's access controls to radiologically significant areas.

The inspector observed activities at various radiologically-controlled-area (RCA) control points to verify compliance with requirements for RCA entry and exit, dosimetry placement, and issuance and use of electronic dosimeters. On July 9, 2001, the inspector toured and observed activities on various elevations in the Unit 1 facilities including the nuclear service and chemical systems buildings, the fuel handling floor, and the vapor containment. On July 10, the inspector toured and observed activities on various elevations in the Unit 2 facilities including the primary auxiliary and turbine buildings. During these observations and tours, the inspector reviewed the posting, labeling, barricading, and level of radiological access control for locked high radiation areas (LHRAs), high radiation areas (HRAs), radiation and contamination areas, and radioactive material areas. On July 11, the inspector attended and observed the conduct of a pre-job briefing for a containment entry at 100% power on radiation work permit (RWP) 01-0007 which was to take place on the following day. During these tours and discussions with the licensee, the inspector noted that a new computerized health physics access control and record system was in use and that the cumulative dose for the six-month period of January through June was a historical low for the site for any six-month time period.

The inspector reviewed a safety evaluation screening determination (00-638-PR) concerning low levels of radioactive contamination in storm drains outside the chemical systems building. Inspector review of a related licensee investigation noted that there have not been any unmonitored liquid radioactive releases via the storm drain system over the last year, and that two previous Condition Reports (CRs) (CR 2000-09854 dated 12-05-2000, and CR 2001-04222 dated April 30, 2001) have investigated radioactivity in the storm drain system. In addition, procedure IPC-ST-M12-S requires that the storm drain liquid discharge pathways be sampled on a monthly basis. NRC inspections indicate that the storm drain discharge point in the discharge canal is upstream of a routine effluent sampling point of the Radiological Environmental Monitoring Program and thus any significant releases via this pathway would be monitored at that location.

The inspector selectively examined the following procedures, records, and other program documents.

- Procedure IPC-ST-M12-S, Rev. 2, Sampling of potentially radioactive effluent release pathways
- RWP 010007, Rev. 02, Unit 2 reactor containment entries
- RWP 010133, Rev. 02, Unit 1 lighting modification and replacement
- Radiological surveys of site areas outside of the RCA performed on April 20 and 25, and on May 1 and 2, 2001
- Safety evaluation applicability determination no. 01-0463-EV-00-AD, Position on the storm drain system and Bulletin 80-10
- Indian Point 1 Safety analysis report
- Second quarter 2001 review of the Radiation Protection Program per SAO-315
- Radiological assessor report for second quarter of 2001
- Electric Power Research Institute optimized site-specific As Low As Reasonably Achievable assessment, Indian Point 2, May 14-22, 2001

The inspection included a review of the following Condition Reports (CRs) for the appropriateness and adequacy of event categorization, immediate corrective action, corrective action to prevent recurrence, and timeliness of corrective action: Condition Reports 200104054, 200104120, 200104322, 200104710, 200105534, and 200106919.

The review was against criteria contained in 10 CFR 19.12, 10 CFR 20 (Subparts D, F, G, H, I, and J), site Technical Specifications, and site procedures.

b. Issues and Findings

No significant findings were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope (71121.03)

The inspection included the following activities to determine the accuracy and operability of radiation monitoring instruments that are used for limiting occupational exposure.

The inspector observed the condition and operability of selected installed radiation monitors in the nuclear service and chemical systems buildings of Unit 1 and in the primary auxiliary, fan, superheater, and auxiliary boiler feed pump buildings of Unit 2.

The inspector reviewed the certification records for two calibration sources and examined the adequacy of the following calibration records.

- Reference source calibration certificate for source no. 314H, Barium-133, 1.73 micro curies on March 14, 1985
- Reference source calibration certificate for source no. 314B, Cesium-137, 1.09 micro curies on February 1, 1985
- PC-EM30, Rev. 5, Process radiation monitor R-41/42 calibrations, January and March 2000 and July 2001 (R-41 and R-42 containment air particulate and gas radioactivity monitors)
- PC-R25, Rev. 8, Main steam line radiation monitors radiation calibration, October 1999 (R-28, R-29, R-30, and R-31 main steam line radiation monitors)
- PC-R38, Rev. 6, High range containment area radiation monitors, June 2000 (R-25 and R-26 high range containment area radiation monitors)

The inspection also included a review of Condition Reports addressing installed radiation monitor issues. The following Condition Reports were reviewed for the appropriateness and adequacy of event categorization, immediate corrective action, corrective action to prevent recurrence, and timeliness of corrective action: Condition Reports 200000183, 200105906, 200106010, 200106182, 200106491, 200106717, and 200106877.

b. Issues and Findings

No significant findings were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification

.1 Occupational Exposure Control Effectiveness

a. Inspection Scope (71151)

The inspector selectively examined records used by the licensee to identify occurrences involving high radiation areas, very high radiation areas, and unplanned personnel exposures for the period from April of 2001 to the time of this inspection against the applicable criteria specified in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 0, to verify that all conditions that met the NEI criteria were recognized and identified as Performance Indicators. The inspector reviewed records/activities included corrective action program records (Condition Reports) and reviews of daily individual and RWP exposures. The inspector also examined Station Administrative Order No. 114, Preparation of NRC and WANO Performance Indicators, Revision 1. This inspection, in conjunction with the review of records in a previous inspection report (Report No. 05000247/2001-004), did not find any problems with the PI accuracy or completeness and thus verified this performance indicator.

b. Issues and Findings

No significant findings were identified.

.2 Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope (71151)

The inspector reviewed the licensee's performance indicator data collecting and reporting process as described in procedure SAO-114, "Preparations of NRC and WANO Performance Indicators." The purpose of the review was to determine whether the methods for reporting PI data are consistent with the guidance contained in NEI 99-02, Revision 0, "Regulatory Assessment Performance Indicator Guidelines." The inspection included a review of the indicator definitions, data reporting elements, calculations, definition of terms, and clarifying notes for the performance indicators.

The inspector reviewed control room log entries, condition reports and previous NRC inspection reports to independently verify licensee's reported information associated with this indicator. The inspector reviewed the plant data from the 3rd quarter of 2000 until the 2nd quarter of 2001.

b. Issues and Findings

No significant findings were identified

.3 Safety System Unavailability - Auxiliary Feedwater

a. Inspection Scope (71151)

The inspector reviewed the licensee's performance indicator data collecting and reporting process as described in procedure SAO-114, "Preparations of NRC and WANO Performance Indicators." The purpose of the review was to determine whether the methods for reporting PI data are consistent with the guidance contained in NEI 99-02, Revision 0, "Regulatory Assessment Performance Indicator Guidelines." The inspection included a review of the indicator definitions, data reporting elements, calculational methods, definition of terms, and clarifying notes for the performance indicators.

The inspector reviewed maintenance rule tracking, control room logs, condition reports associated with the auxiliary feedwater system, and discussed observations with cognizant Licensee personnel. The inspector reviewed plant data from the 1st quarter in 2000 through the 1st quarter in 2001 for the three trains of auxiliary feedwater.

b. Issues and Findings

No significant findings were identified.

.4 Supplemental Inspection - Unplanned Scrams Per 7000 Critical Hours Performance Indicator

a. Inspection Scope (95001)

The Indian Point 2 performance indicator (PI) for “Unplanned Scrams per 7000 Critical Hours” exceeded the white band threshold value starting the second quarter of 2000, and returned to the green performance band during the third quarter of 2000. The number of unplanned scrams increased due to the manual scram that plant operators inserted during a steam generator tube failure event that occurred on February 15, 2000. Prior to that, on August 31, 1999, the plant had tripped automatically while corrective maintenance was being performed on the reactor protection system.

The NRC’s reviews of the events that involved the scrams were documented in the following inspection reports:

August 31, 1999 Event

- NRC Augmented Inspection Team - Reactor Trip With Complications Report 05000247/1999-08
- Follow Up to the Augmented Inspection Team Report 05000247/1999-13
- Enforcement Follow Up Inspection to the Augmented Inspection Team Report 05000247/1999-14

February 15, 2000 Event

- NRC Augmented Inspection Team - Steam Generator Tube Failure Report 05000247/2000-02
- Augmented Inspection Team Follow Up - Steam Generator Tube Failure Report 05000247/2000-07
- Special Inspection - Indian Point Unit 2 Steam Generator Tube Failure Report 05000247/2000-10
- Emergency Preparedness Program Report 05000247/2000-06

In addition, NRC assessments of the event causes and corrective actions are documented in other inspection reports, including:

- Indian Point 2 Problem Identification and Resolution Inspection Report 05000247/2000-12
- Indian Point 2 Inspection Report 05000247/2000-14
- NRC Supplemental Inspection 95003 Multiple Degraded Cornerstones Report 05000247/2001-02

b. Issues and Findings

The licensee did not initiate a specific condition report for crossing the PI threshold for unplanned reactor scrams. However, root cause evaluations, extent of condition reviews, audits, self-assessments, and corrective action effectiveness reviews provided assurance that the root and contributing causes of the scrams were understood and captured in the licensee’s corrective action program. The NRC verified that human and equipment performance issues and organizational process weaknesses have been addressed in the Indian Point 2 business plan and sub-tier documents. Broad corrective actions are in progress to address issues in the areas of plant configuration control, technical support of operations, operator performance and procedure quality, management oversight of events, and corrective action and emergency planning program implementation. Schedules have been established in the business plan for implementing and completing corrective actions, and quantitative or qualitative measures of success continue to be developed or refined to determine the effectiveness of corrective actions to prevent recurrence.

Based on the above licensee actions, the white performance indicator for Unplanned Scrams will be removed from consideration in future NRC actions, per the Action Matrix, in accordance with the guidance in NRC Inspection Manual 0305, “Operating Reactor Assessment Program.”

4OA2 Cross Cutting Issues

a. Inspection Scope (71153)

The inspector reviewed several events during the period that were indicative of an adverse trend in human performance and problem identification and resolution.

b. Issues and Findings

.1 Problem Identification and Resolution

(No Color) The licensee failed to document a condition report on repeated failures of a post-maintenance test associated with the 23 emergency diesel generator (EDG). Specifically, on July 25 and July 26, 2001, the 23 EDG could not achieve 2,300 kilowatts (30 minute rating) following governor oil replacement. The post maintenance test (PMT) was the monthly surveillance PT-M21C, “Emergency Diesel Generator 23 Load Test,” step 7.29. The monthly surveillance normally loads the EDG to 1,750 kW except as identified in step 7.29. The procedure step directs the operators to load the EDG to 2300 kilowatts (kWs) and a reactive load between 0 - 200 kilovolt amperes reactive (KVAR). On July 25 the 23 EDG reached 2250 kW and on July 26 the engine reached 2275 kW.

The licensee performed an evaluation that concluded the EDG was operable since the mechanical governor had additional mechanical margin and the generator administrative limitations (terminal voltage) with the voltage regulator were met prior to the operator achieving full kilowatt load. Further, operator adjustments of offsite voltage (using the station auxiliary tap changer) would place the facility in Technical Specification 3.0.1. The inspector confirmed by review of the operability determination that the EDG successfully demonstrated full load capability in accordance with TS surveillance 4.6.A.2 in May, 2000. The inspector also verified that inlet air temperatures were within the EDG design and that governor adjustments and setup were consistent with vendor instructions.

The inspector observed that no condition report was prepared for this failure of the PMT associated with the 23 EDG. Numerous condition reports (CR 199810268, 200003415, 200003494, 200003541, 200004426, 200004462) in the last three years from other PMTs and TS 4.6.A.2 surveillance testing existed on EDGs not obtaining appropriate loading due to offsite grid conditions with the generator at its parameter limits. Corrective actions have not effectively resolved this testing configuration deficiency.

This issue was more than minor because failure to properly identify and/or preclude recurrence in the problem identification and resolution program indicates an adverse trend as documented in recent NRC inspection reports (2001-004, 2001-03, 2001-02, and 2000-12).

The failure to initiate a condition report for a condition adverse to quality (failure of a PMT for the EDG) is considered a violation of 10 CFR 50 Appendix B, criterion XVI. This issue had low actual safety significance because EDG operability was not compromised in the failure to achieve the PMT acceptance criteria. The licensee initiated condition report 200108257 after discussions with the inspector. This violation is being treated as a Non-Cited violation, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000 (65 FR 25368) **(NCV 50-247/01-08-03)**

.2 Human Performance

(Green) Poor communications resulted in a lack of timely awareness of a degraded condition associated with main turbine protection from an offsite 345 kV fault. Specifically, untimely communications existed between plant operations staff and the Buchanan service personnel that resulted in a delayed recognition of an inoperable pilot wire protection between January 2001 through July 10, 2001. Further, on July 17, 2001, after initial circuit troubleshooting, inaccurate drawings for offsite protection equipment and poor configuration control were identified (a spare 125 volt DC breaker was open instead of closed as required). The protection system remained inoperable at the end of the inspection period. Though the drawings and configuration control issues are not maintained by Indian Point Unit 2 personnel, they did impact the function of the facility as described in the UFSAR section 8.1.1 and 14.1.6.2. Further, the 345 kV system is scoped in the maintenance rule (10CFR50.65) with a system boundary being protection and pilot wiring relaying for the generator output breakers.

This issue is more than minor in that it had a credible impact on safety because of the lack of automatic transfer of loads from the unit auxiliary transformer to the station auxiliary transformer during a postulated 345 kV transient. Operator action would be required to restore power to two of four safeguards buses. The issue impacts the mitigation system cornerstone. The actual safety significance is low per the Significance Determination Process since no actual safety function was lost, or loss of a train greater than its Technical Specification allowed outage time occurred, or loss of a risk significant system for greater than 24 hours.

4OA5 Other- Engineering Projects

.1 Design Engineering Projects

a. Inspection Scope

The inspector reviewed the Indian Point 2 year 2001 business plan with a primary focus on the projects included within the design engineering department section of the plan. The inspector reviewed the design engineering projects to assess the adequacy of each project scope. The extent to which each project should, when completed, improve the availability, retrievability and accuracy of plant design bases information was also examined. In addition, the inspector reviewed a sample of open issues assigned to design engineering to determine the extent that significant issues were included in an appropriate business plan project or were being considered for addition to the 2002 business plan. Items reviewed included condition reports and corrective actions assigned to engineering, work orders on engineering hold, planned plant modifications, maintenance rule system corrective action plans, control room deficiencies and temporary modifications.

The inspector also reviewed the current status for various projects and the planned completion dates. In addition, the status of commitments made as part of the 10 CFR 50.54(f) design bases review project were reviewed.

b. Issues and Findings

The inspector found that the scope of projects appeared to be appropriate, and when completed, should result in improved availability, retrievability and accuracy of design bases information. The inspector found that open engineering issues that involved major projects were already in the 2001 business plan scope or were being evaluated for addition to the 2002 business plan. For example, recent problems with the reactor protection system wiring resulted in a new project being planned for inclusion in the 2002 business plan. This project will include actions to ensure wiring within the RPS system is consistent with plant drawings and will review wiring in other systems, such as the engineered safeguards actuation system, to determine if similar discrepancies may exist in those systems.

The inspector also found that the ongoing projects were adequately staffed with licensee personnel, and for many projects outside contractor and consultant resources were being utilized to augment the licensee staff efforts. The inspector noted that many projects were in their early stages and process improvements were continuing to be implemented. Although some projects have been completed, most projects were not far enough along to effectively assess. Some are scheduled to be completed by the end of 2001, while several projects involved long term, multi-year efforts that will continue in some cases until 2004. As a result, it was too early for the inspector to assess the overall quality or effectiveness of the improvement efforts.

4OA6 Meetings

Exit Meeting Summary

On August 24, 2001, the inspector presented the inspection results to Mr. A. Blind and other members of the licensee staff who acknowledged the findings. The inspector asked whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT 1

a. **Key Points of Contact**

M. Donegan	Health Physics/Radioactive Waste Manager
J. Groth	Chief Nuclear Officer
T. McCafferty	System Engineering Manager
M. Miller	Manager, Generation Support
G. Schwartz	Chief Engineer
W. Smith	Manager, Operations
R. Sutton	Maintenance Rule Coordinator
J. Touhy	Manager, Design Engineering
T. Wadell	Manager, Maintenance

b. **List of Items Opened, Closed, and Discussed**

Opened

2001-08-01	UNR	Adequacy of procedural guidance and maintenance of mitigating equipment for internal floods

Opened and Closed During this Inspection

2001-08-02	NCV	Failure to consider risk pursuant to 10 CFR 50.65(a)(4)
2001-08-03	NCV	Failure to initiate Condition Report pursuant to 10 CFR 50 Appendix B, Criterion XVI

c. **List of Acronyms**

AFW	auxiliary feedwater
AOI	Abnormal Operating Instruction
COL	checkoff list
CR	condition report
CVCS	chemical and volume control system
DBD	design basis document
EDG	emergency diesel generator
HRA	high radiation area
IPEEE	Individual Plant Examination of External Events
IVSWS	isolation valve seal-water system
KV	kilovolt
KVAR	kilovolt amperes reactive
KW	kilowatts
LER	licensee event report
LHRA	locked high radiation area
MBFP	main boiler feed pump
NEI	Nuclear Energy Institute
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
PARS	publicly available records
PCV	pressure control valve

PI	performance indicators
PMT	post-maintenance test
RCA	radiologically controlled area
RWP	radiation work permit
SAO	station administrative order
SDP	significance determination process
SER	Safety Evaluation Report
SOP	system operating procedure
SOV	solenoid operated valve
TSC	technical support center
TFC	temporary facility change
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report