February 12, 2002

Mr. Fred Dacimo
Vice President - Operations
Entergy Nuclear Operations, Inc.
Indian Point Nuclear Generating Units 1 & 2
295 Broadway, Suite 1
Post Office Box 249
Buchanan, NY 10511-0249

SUBJECT: INDIAN POINT 2 - NRC INSPECTION REPORT 50-247/01-11

Dear Mr. Dacimo:

On December 29, 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 January 9, 2002, with 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. Additional inspection hours were performed this period, primarily in response to licensed operator requalification failures that had previously occurred. Recent emergency plan document changes were reviewed in-office during this period. The inspection also reviewed the radiation safety and effluent monitoring programs. Within these areas, the inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel.

In response to the Licensed Operator Requalification failures, NRC staff performed a number of special inspections, reviews, and operational evaluations to confirm the adequacy of licensee corrective actions, and the ability of the operating crews to operate the plant safely. The NRC activities included round-the-clock observations of licensed operator activities during the period of December 12 - 23, 2001 (monitoring all five operating crews), as well as enhanced monitoring through the end of the inspection, which included operator response to the reactor trip on December 26, 2001. Although one violation, identified below, is related to operator performance, this was an exception to otherwise acceptable performance.

Immediately following the terrorist attacks on the World Trade Center and the Pentagon, the NRC issued an advisory recommending that nuclear power plant licensees go to the highest level of security, and all promptly did so. With continued uncertainty about the possibility of additional terrorist activities, the Nation's nuclear power plants remain at the highest level of security and the NRC continues to monitor the situation. This advisory was followed by additional advisories, and although the specific actions are not releasable to the public, they generally include increased patrols, augmented security forces and capabilities, additional security posts, heightened coordination with law enforcement and military authorities, and more limited access of personnel and vehicles to the sites. The NRC has conducted various audits of your response to these advisories and your ability to respond to terrorist attacks with the capabilities of the current design basis threat (DBT). From these audits, the NRC has concluded that your security program is adequate at this time.

Based on the results of this inspection, three violations of NRC requirements were identified regarding the failure to adhere to a system operating procedure during a dilution of the reactor coolant system, the failure to account for instrument errors in operating procedures used during shutdown conditions, and weaknesses in and untimely corrective actions for instrument errors associated with overpressure protection system operations. 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/reading-rm.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 50-247/01-11

Attachment 1 - Supplemental Information

cc w/encl: J. Yelverton, Chief Executive Officer
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L. Temple, General Manager - Operations
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J. McCann, Manager, Nuclear Safety and Licensing
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Mayor, Village of Buchanan
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REGION I

Docket No.	50-247
License No.	DPR-26
Report No.	50-247/01-11
Licensee:	Entergy Nuclear Operations, Inc.
Facility:	Indian Point 2 Nuclear Power Plant
Location:	Buchanan, New York 10511
Dates:	November 18, 2001 - December 29, 2001
Inspectors:	William Raymond, Senior Resident Inspector Peter Habighorst, Resident Inspector John R. McFadden, PhD, Health Physicist David Silk, Emergency Preparedness Specialist Jason Jang, PhD, Senior Radiation Specialist Todd Fish, Licensed Operator Examiner Joe D'Antonio, Licensed Operator Examiner Laura Dudes, Senior Resident Inspector Harold Gray, Senior Reactor Inspector James Trapp, Senior Reactor analyst Julian Williams, Reactor Inspector Javier Brandt, Resident Inspector Glen Dentel, Senior Resident Inspector Antone Cerne, Senior Resident Inspector Lois James, Resident Inspector George Morris, Reactor Inspector Alan Blamey, Licensed Operator Examiner Steve Pindale, Reactor Inspector Peter Drysdale, Senior Resident Inspector Wayne Schmidt, Senior Reactor Engineer Scott Schwind, Resident Inspector Tom Morrissey, Resident Inspector Frank Brush, Resident Inspector Jimi Yerokun, Senior Reactor Engineer Scott Barber, Senior Project Engineer Leanne Harrison, Project Engineer
Approved by:	Peter W. Eselgroth, Chief Projects Branch 2 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000247-01-11, on 11/18 - 12/29/2001, Entergy Nuclear Operations, Inc.; Indian Point 2 Nuclear Power Plant. Personnel Performance During Non-Routine Plant Events, Licensed Operator Requalification, and Cross-Cutting Issues.

The report covered a 6 week period of inspection by resident inspectors, Senior Operations Engineers, Operations Engineers, and a Senior Health Physicist. No findings of significance were identified. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

Cornerstone: Initiating Events

GREEN While making a routine RCS dilution on December 17, 2001, an operator error resulted in an inadvertent dilution of 6 additional gallons of primary water (a total of 42 gallons was added versus the 36 gallons planned). The error occurred because the operator failed to place the Mode switch to AUTO per Step 4.3.16(4) of SOP 3.2 when securing the CVCS from the Dilution mode. The failure to follow procedures was contrary to Technical Specification 6.8.1.a. The inadvertent RCS dilution was classified as a reactivity management event. In accordance with the NRC Manual Chapters 0609, "Significance Determination Process," and 0610*, "Power Reactor Inspection Reports," this issue was determined to be more that minor because an inadvertent dilution of the RCS, if left uncorrected, could become a more significant safety concern. When evaluated in accordance with the SDP Phase 1, the issue was considered to be of very low safety significance since there was no actual challenge to reactor safety or the status of mitigating safety systems. The licensee identified this procedure violation (reference condition report 200112470). This failure to adhere to a procedure 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) **(NCV 50-247/01-11-01)**.

GREEN On December 26, 2001, the reactor was automatically shutdown in response to a trip of the main turbine. The plant trip was caused by the failure of a non-safety related protection relay following a disturbance in the 345 KV electrical system that resulted in a partial load reject of the main generator output. The plant response was complicated by the de-energization of 6.9 KV buses 1 through 4, resulting in the shutdown of all four reactor coolant pumps, the de-energization of two of four 480 volt safeguard buses (safety buses 2A and 3A), and a loss of some of the operating condensate and circulating water pumps. The trip response was further complicated by equipment problems that resulted in the loss of the main condenser. For the fault that occurred in the 345 KV electrical system, the plant electrical response was as expected in accordance with the plant design. The licensee post trip evaluation demonstrated that turbine and reactor limits were not exceeded. The operators responded properly to the trip and the equipment performance problems. In accordance with NRC Manual Chapters 0609, "Significance Determination Process," and 0610*, "Power Reactor Inspection Reports," this issue was determined to be more that minor because a reactor trip is a transient initiator and the plant transient with electrical complications could be a significant safety concern if the lost safety equipment was not readily recovered. When evaluated in accordance with the SDP Phase 1, the issue was considered to be of very low safety significance since there was no impact on the plant safety barriers and the impact on mitigating safety equipment availability was minimal.

Cornerstone: Barrier Integrity

GREEN Entergy determined that the plant operated in violation of the RCS overpressure protection requirement of TS Figure 3.1.A-2 on four separate time periods in the year 2000 with a total exposure of approximately 49 hours (LER 2001-05). The cause was the failure to account for instrument errors in operating procedures used for controlling plant conditions in accordance with TS Figure 3.1.A-2. This issue was evaluated in the SDP process (Manual Chapter 0609 Appendix G) for a violation of the low temperature overpressure protection technical specifications. During the times when the facility operated outside TS Figure 3.1.A-2, all appropriate administrative controls to limit the potential for unwarranted heat-up or mass addition to the reactor coolant system were implemented by operators. The consequence of this error potentially reduced the required operator response time for a postulated overpressure events as previously approved in the plant licensing basis. No reactor coolant system overpressure condition existed during these times and the 10 CFR 50 Appendix G limits were not exceeded. However, the multiple failures to adhere to TS Figure 3.1.A-2 due to inadequate procedures is considered a violation of TS 3.1.A.4 and TS 6.8.1.a. These violations are treated as a Non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000 (65 FR 25368). A TS Amendment was submitted and was under review at the end of the inspection.

Cross-Cutting Issues

No Color The licensee’s corrective actions in response to condition report 200004598 were untimely and ineffective to preclude the violation of TS figure 3.1.A-2. Condition report 200004598 initiated on June 16, 2000 identified that instrument uncertainty as stated in the TS basis was not incorporated in either the engineering analyses for the TS heatup and cooldown curves or the instrumentation for the power operated relief valve setpoints. The licensee failed to also consider the implication on the TS curves when the overpressure protection system (OPS) is not considered operable and no reactor coolant system vent space exists. The corrective actions in response to this CR failed to preclude plant operations in violation of TS figure 3.1.A-2 on July 2, August 3, and November 30, 2000. This violation of 10 CFR 50 Appendix B, Criterion XVI had low actual safety significance because no consequence to the reactor coolant system pressure boundary occurred. 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).

TABLE OF CONTENTS

SUMMARY OF FINDINGS ii

TABLE OF CONTENTS iv

Report Details 1

SUMMARY OF PLANT STATUS 1

1. REACTOR SAFETY 1
   1R05 Fire Protection 1
   1R11 Licensed Operator Requalification 1
   1R13 Maintenance Risk Assessment and Emergent Work Activities 7
   1R14 Personnel Performance During Non-Routine Plant Events 7
   1R19 Post Maintenance Testing 14
   1R22 Surveillance Testing 14
   1R23 Temporary Plant Modifications 15
   1EP4 Emergency Action Level and Emergency Plan Changes 16

2. RADIATION SAFETY 16
   2OS1 Access Control to Radiologically Significant Areas 16
   2OS3 Radiation Monitoring Instrumentation 17
   2PS1 Gaseous and Liquid Effluents 18

4. OTHER ACTIVITIES (OA) 20
   4OA1 Performance Indicator Verification 20
   4OA2 Cross Cutting Issues 20
   4OA3 Inspection Item Followup 21
   4OA4 Licensee Event Report Reviews 22
   4OA6 Meetings 23

Key Points of Contact 24

List of Items Opened, Closed, and Discussed 25

List of Acronyms 26

Report Details

SUMMARY OF PLANT STATUS

The plant operated at full power during the inspection period until December 26, 2001, when an electrical disturbance in the offsite 345KV switchyard caused an automatic turbine trip and reactor trip at 7:20 a.m. Following a review of the event causes and the plant response, and after completing repairs to plant systems, Entergy restarted Indian Point 2. The reactor was taken critical at 2:35 p.m. on December 28, and the main generator was synchronized with the electrical grid at 4:50 a.m. on December 29. The plant was at 100% FP at 10:00 a.m. on December 30 and continued to operate at full power for the remainder of the inspection period.

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

1R05 Fire Protection

.1 Fire Drills

a. Inspection Scope (71111.05)

The inspector observed fire brigade drills on December 7 and 17, 2001, which were conducted in accordance with pre-planned drill scenarios. The December 17 activity was a Mutual Fire Aid Drill with the Verplank Fire Department. The inspector evaluated the fire brigade readiness to fight fires with properly donned protective clothing and self-contained breathing apparatus (SCBA). The inspector confirmed the brigade entered the fire area in a controlled manner and brought sufficient fire fighting equipment. The inspector confirmed that the drill scenario was followed and the pre-planned fire fighting strategy was used. The inspector confirmed that the drill objectives were met and the licensee critiqued the training session. Inspector observations regarding the December 17 drill critique were discussed with the licensee. Fire protection related deficiencies were entered in the corrective action program as Condition Reports 200112093, 200112130, 200112504 and 200200047.

b. Issues and Findings

No significant findings were identified

1R11 Licensed Operator Requalification

.1 Conduct of Simulator Operating Evaluations

Background

After the requalification inspection of October 22, 2001, requalification exam results indicated a preliminary yellow finding based on crew high failure rate (details of that inspection are in NRC Inspection Report 50-247/2001-013). On November 15, 2001, the licensee informed NRC that crew D failed a licensee-conducted evaluation administered November 14. This crew was also one of the crews that had failed its requalification exam. IP2 staff informed the NRC that they had immediately removed crew D from licensed duties pending further evaluation and probable replacement of several of the operators on the crew.

a. Inspection Scope

During the week of November 19-21, 2001, the inspector reviewed the nature of the failure and discussed the licensee's follow-up response to the failure. Following NRC questioning, the licensee evaluated one other crew that, similar to crew D, had failed its annual requalification exam, had been remediated, and then had returned to shift. The facility administered this evaluation on November 27. The inspector co-evaluated the crew's performance. The facility and the inspector both determined that the crew passed its evaluation.

Also, during the week of November 19, 2001, the NRC decided to conduct operational evaluations of crew D before that crew returned to shift since the facility had decided to replace three operators from the crew, based on their poor performance history. Subsequently, on December 6, 2001, the inspector validated two scenarios to be used during the evaluation and verified that the scenarios met or exceeded the scenario attributes outlined in Attachment 11 of IP 71111. On December 7, 2001, the inspectors conducted operational evaluations on the restaffed crew D, with the facility co-evaluating. The crew passed the evaluation.

While onsite for the operational evaluations, the inspector also directly observed control room activities of two crews.

During the week of December 10, 2001, NRC staff decided to perform additional operational evaluations for four RO staff licenses who failed the annual operating test and were to go back on shift. These individuals were to replace current watchstanders on an as-needed basis, but with no more than one staff license being used per operating crew.

Subsequently, during the week of December 16, 2001, the inspector validated two scenarios developed by the facility and verified that these scenarios met or exceeded examination standards. These scenarios were also tailored to test the operators on knowledge and ability weaknesses previously identified by the facility staff, e.g., procedure use and adherence, ability to diagnose events and conditions, and understanding of plant system and response. The inspectors conducted the operational evaluations on December 17 and 18, with facility staff co-evaluating. The four staff licenses passed their evaluations. The licensee evaluation was in agreement.

b. Findings

No findings of significance were identified.

.2 Enhanced Monitoring of Control Room Activities

a. Inspection Scope (71111.20)

As a result of the performance by plant operators in the 2001 Licensed Operator Requalification Program (reference NRC inspection 50-247/01-13), Entergy identified corrective actions in a November 5, 2001 letter to the NRC which included increased management oversight of shift activities through the use of shift mentors. The inspector implemented an augmented inspection plan during routine plant operations to permit long-term, heightened observation of control room activities and operator performance. The augmented inspection used resident and region-based inspectors and included observations during periods of day-time and night shifts.

The inspector monitored control room activities to verify operators, control room supervision and shift managers remained cognizant of plant conditions and work activities in the field. The inspector reviewed licensee actions to implement enhanced management oversight of shift activities, and to implement a shift mentor program. The inspector monitored operator actions for conformance with the following operations administrative directives (OAD):

- OAD 2, Watch Relief, Revision 24 (Turnover and End of Watch Critique)
- OAD 3, Plant Surveillance and Log Keeping, Revision 37
- OAD 6, Equipment Status Control, Revision 30 (Self and Peer Checking)
- OAD 9, Operations Section Organization, Revision 28 (Overtime)
- OAD 15, Conduct of Operations, Revision 51 (Conservative Operations)
- OAD 33, Procedure Adherence and Use, Revision 21 (Annunciator Response)
- OAD 35, Communications, Revision 5 (Crew Briefs and Updates)
- OAD 39, Reactor Power Control, Revision 9 (Reactivity Management)
- SOP 3.2, Reactor Coolant System Boron Concentration Control, Revision 19

The inspector verified operators responded in a timely manner to unexpected plant conditions, and followed alarm response and other operating procedures. The inspector reviewed various control room indications and discussed with operators the reasons for lit annunciators. Shift logs were reviewed to confirm proper entry into and exit from technical specification limiting conditions for operation for inoperable equipment and documentation of control room activities. Compliance with selected plant technical specifications (TS) and plant procedures were verified.

Shift turnovers and shift briefings were observed to verify the information exchanged was accurate. The inspector verified the operators were aware of and effectively communicated conditions caused by testing and plant work activities. The inspector observed communications between operators and testing personnel to verify clear identification of the planned effect on plant equipment and to verify appropriate control room indications resulted from test and maintenance activities.

The inspector reviewed the working hours for plant operators to determine the amount of overtime used and to verify that licensee management controlled the use of overtime in accordance with the administrative guidance in OAD-9, and monitored the operators for fitness for duty.

b. Issues and Findings

The inspector confirmed the safe operation of Indian Point 2 during the period of enhanced monitoring. The inspector confirmed safe plant operations was evident by observing general plant operations, the operational alignment and control of safety systems during maintenance and test activities, and compliance with the limiting conditions for operations specified in the technical specifications. The inspectors noted a conservative approach to plant operations when confronted with off-normal conditions, such as the response to annunciators regarding equipment parameters and status, and degraded equipment conditions. The Shift Mentors were involved and interacted with the crews to provide real time feedback on performance, coaching on management expectations, and counseling of the Shift Manager in his role as a manager. The Shift Mentors made recommendations to Entergy Management on areas needing improvement.

Inspector observations of performance deficiencies having minor safety significance were discussed with licensee management, which included examples of inconsistent performance in the implementation of the guidance in the administrative procedures. The NRC noted areas for improvement in operator actions as was evident in self-checking, three-part communications, peer checking, pre-job briefings, procedure quality and use, equipment control, logging entry into technical specification LCOs, and housekeeping. Other areas for improvement included central control room lighting and noise reduction due to normal ventilation and a recirculation fan. The number of routine work activities was high at times and challenged the operating crew to control and sequence activities within the control room. This indicated the need to improve work control to minimize operator distractions.

GREEN In the area of reactivity management, the inspector noted generally acceptable oversight and control of dilutions, with direction from the control room supervisor. The NRC noted Entergy highlighted management expectations on reactivity management through the issuance of a Night Order regarding SOP 3.2 on December 15 and the conduct of crew briefs. Minor exceptions to acceptable controls were discussed with licensee management. There was one example of inadequate reactivity management, as described below, which was an exception to otherwise acceptable performance.

While making a routine RCS dilution on December 17, 2001, an operator error resulted in an inadvertent dilution of 6 additional gallons of primary water (a total of 42 gallons was added versus the 36 gallons planned). The error occurred because the operator failed to correctly perform SOP 3.2 by not performing Step 4.3.16(4) when securing the CVCS from the Dilution mode. The operator immediately recognized his error when he performed Step 4.3.16.(5) and he stopped the further addition of primary water. The licensee estimated that the 6 gallon dilution resulted in a reactivity insertion of 2 percent millirho (pcm). There was no appreciable impact on reactivity since the dilution was terminated prior to deviation of reactor temperature from the acceptable band. There was no actual plant safety consequence from this error.

The error revealed the failure of several barriers in the licensee controls for reactivity management: the operator's poor self-checking and procedure use (place keeping in SOP 3.2); inadequate peer checking by the second operator; inadequate oversight of the dilution by the Control Room Supervisor, who was in the control room but involved in a concurrent fire drill.

Entergy issued CR 200112470 and evaluated the inadvertent dilution as a reactivity management event per Station Administrative Order 442. Immediate corrective actions included a crew standdown on December 17 to review the event and expectations on the conduct of duties; briefings with the Operations Manager and Plant Manager, the assignment of Significance Level 2 to the CR to determine event cause(s), and the expedited review of the event by the Corrective Action Review Board.

In accordance with the NRC Manual Chapters 0609, "Significance Determination Process," and 0610*, "Power Reactor Inspection Reports," this issue was determined to be more that minor because an inadvertent dilution of the RCS, if left uncorrected, could become a more significant safety concern. When evaluated in accordance with the SDP Phase 1, the issue was considered to be of very low safety significance since there was no actual challenge to reactor safety or the status of mitigating safety systems.

Technical Specification 6.8.1.a, requires, in part, written procedures to be implemented for activities referenced in Appendix "A" of regulatory Guide 1.33, Rev. 2, which includes procedures for operating the reactor and the chemical and volume control system. Station Operating Procedure SOP 3.2, Reactor Coolant System Boron Concentration Control, Revision 19, Step 4.3.16.(4) requires the operator the place the RCS Makeup Mode Selector switch to AUTO. Contrary to this requirement, on December 17, 2001, the operators failed to perform this step and place the Mode switch to AUTO. The failure to perform Step 4.3.16.(4) resulted in the inadvertent dilution of the RCS. The licensee identified this procedure violation (reference condition report 200112470). The failure to adhere to a procedure 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). **(NCV 50-247/01-11-01)**

1R12 Maintenance Rule Implementation - Biennial Inspection IP 71111.12B

a. Inspection Scope

The inspector reviewed maintenance rule (MR) documentation to assess: (1) the scoping and classification of Structures, Systems, and Components (SSC) in accordance with 10 CFR 50.65; (2) the appropriateness of performance criteria for SSCs classified as 10 CFR 50.65(a)(2); (3) the characterization and corrective actions for failed SSCs and, (4) the goals and corrective actions for SSCs classified as 10 CFR 50.65(a)(1). The inspector reviewed performance-based problems involving in-scope SSCs to assess the effectiveness of the maintenance rule program and the coding of system failures in the corrective action program to independently assess the adequacy of the MR implementation for the selected risk-significant items. The inspector also reviewed system health reports and the licensee's action plans to improve system reliability. The inspector interviewed system managers and maintenance rule personnel.

The inspector reviewed selected 10 CFR 50.65(a)(1) high risk significant systems to determine if: (1) goals and performance criteria were appropriate, (2) industry operating experience was considered, (3) corrective action plans were effective, and (4) performance was being effectively monitored. In this area, the inspector reviewed the following systems:

- Safety Injection System Actuation (SISA)
- Emergency Diesel Generator (EDG) HVAC System
- Chemical and Volume Control System (CVCS)

The inspector reviewed selected 10 CFR 50.65(a)(2) high risk significant systems, to verify that performance was acceptable. In this area, the inspector reviewed the following systems:

- Auxiliary Feedwater (AFW) System
- 480V Electrical System,

The inspector reviewed the periodic evaluations required by 10 CFR50.65 (a)(3) to verify that the structures, systems and components within the scope of the maintenance rule were included in the evaluations and that balancing of reliability and unavailability of SSCs was given adequate consideration. The inspector reviewed the licensee's periodic evaluation which covered the period from January 1998 through December 1999 (the next evaluation will cover the period, January 2000 - December 2001). In addition, to obtain an assessment of current performance, the inspector reviewed the 1st, 2nd and 3rd Maintenance Rule quarterly reports for the year 2001.

The inspector reviewed selected items in the corrective action program to verify that the licensee was identifying issues related to the Maintenance Rule at an appropriate threshold, entering them in the corrective action program, and prescribing the appropriate corrective actions. The Condition Reports reviewed are listed in Attachment 1 of this report.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Activities

a. Inspection Scope (71111.13)

The inspector observed selected portions of emergent maintenance work activities to assess Entergy's risk management. The inspector evaluated the effectiveness of the risk assessments performed for emergent operational activity and verified how the licensee managed the risk in accordance with 10 CFR 50.65(a)(4). 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 maintain the functional capability of mitigating systems. The inspector discussed the risk management with maintenance and operations personnel for the following activities:

- Power Range N44 Failure-Module NM-307 and Power Supply Repair (CRs 200111485, 200111495)

b. Issues and Findings

No significant findings were identified.

1R14 Personnel Performance During Non-Routine Plant Events

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.

.1 Operator Response to Potential Steam Generator Leakage

a. Inspection Scope (71111.14)

The inspector reviewed the operator actions on November 29, 2001, to enter Abnormal Operating Instruction (AOI) 1.2, "Steam Generator Tube Leak," Revision 23, based on what was determined to be ambiguous chemistry data regarding steam generator tube leakage (reference Condition Report CR 200111656). Two condenser air ejector (CAE) samples were potentially positive for the radioactive fission noble gas xenon. The operators exited AOI 1.2 after about 10 minutes because the calculated leak rate was about 0.03 gallons per day (gpd) which was well below the AOI 1.2 action level of 5 gpd. The inspector reviewed Entergy actions to revise the procedure entry criteria to require that steam generator leakage increase by at least 1 gpd (relative to zero) before the operators would enter AOI 1.2 (CR 200111655).

The inspector reviewed the licensee's methodologies for detection, validation, and quantification with statistical certainty, of any steam generator tube leakage. Included in the review was the licensee's sampling and analysis methodologies and recent sample analysis results of steam generator secondary side water samples. The inspector reviewed the licensee's bases for setting 0.5 gpd as the minimum reliable detection sensitivity for leakage derived from CAE analyses, which was set as the lower threshold for calculated leak rate to be considered steam generator leakage.

The inspector reviewed the Entergy actions to investigate possible causes for steam generator leakage and to identify other sources for the radioactivity in the CAE. The licensee reviewed the inspection history for the steam generators, and investigated potential sources of foreign material that could cause leakage. The licensee had applied foreign material exclusion controls during steam generator fabrication, storage and installation. The steam generator records showed repairs were completed during initial fabrication. The licensee investigated whether the radioactivity could be the result of a flaw in the tube-end to tube-sheet weld(s). The licensee concluded the postulated flaw(s) responsible for the leakage does not represent a structural integrity concern.

The inspector reviewed Entergy's actions to monitor the steam generators for leakage during operating Cycle 15. The analysis of the CAE effluent for the presence of radioactivity showed negative results from the plant startup in January 2001 through November 2001. Following the November 29 chemistry results, two CAE samples on December 4 were positive for radioactive xenon with a total activity of 4E-8 uCi/cc and an analytical error of about 25%. The CAE effluent showed intermittent positive results with generally large statistical uncertainties through the end of the inspection period. The results remained at or below the lower limits of detectability (LLD), and well below 0.1 gpd. Entergy is continuing to evaluate their sampling and analysis of data. The NRC is continuing its monitoring of the steam generators' very low leakage, and licensee actions.

b. Issues and Findings

No significant findings were identified.

Industry experience is that very low levels of leakage are not uncommon and are often difficult to reliably quantify. There is no experience of rapid tube failure in replacement steam generators exhibiting very low leakage such as exists in this case. In addition, steam generators with the types of material used in the IP2 replacement steam generators have not exhibited stress corrosion cracking related degradation as experienced in older model steam generators such as those originally installed at IP2. The licensee's actions to assess potential degradation mechanisms (e.g., loose parts) and continued monitoring are appropriate.

.2 Reactor Shutdown due to Offsite Electrical System Disturbance on December 26, 2001

a. Inspection Scope (71111.14)

On December 26, 2001, Indian Point 2 was automatically shut down following an electrical disturbance in the offsite 345KV Buchanan Switchyard. The plant trip was caused by the failure of a non-safety related protective relay following a disturbance in the 345 KV electrical system, and was complicated by equipment problems that resulted in the loss of the main condenser. The inspector observed operator performance, reviewed the performance of plant equipment, and evaluated Entergy's event response findings.

b. Issues and Findings

Reactor Trip and Plant Response

GREEN On December 26, 2001, the reactor was automatically shutdown at 7:20 a.m. in response to a trip of the main turbine. The turbine trip was caused by over-frequency relays that actuated in response to a partial load reject of the main generator output. The generator load mismatch with the offsite electrical grid occurred when the north ring bus in the Buchanan Switchyard was isolated from the offsite 345 KV grid following a transient fault on the 345 KV electrical system. Because of the mismatch between the generator output frequency and the station auxiliary transformer frequency, a fast transfer of the power supplies for 6.9 KV buses 1 through 4 did not occur, resulting in the shutdown of all 4 reactor coolant pumps, the de-energization of two of four 480 volt safeguard buses (safety buses 2A and 3A), and a loss of all of the operating condensate and some of the circulating water pumps.

The operators responded to the trip using emergency procedures E-0 and ES-0.1 and implemented abnormal operating procedure AOI 3.4 to verify the proper shutdown of the reactor. All three emergency diesel generators started but did not load their respective safeguards buses, as designed (reference Updated Final Safety Analysis Report UFSAR Section 8.2.3.4). The operators manually restored power to the safety buses 2A/3A using 22 EDG within 10 minutes of the reactor trip and to the 6.9 KV buses within 20 minutes. While verifying the turbine trip per emergency procedure E-0, the operators noted that the turbine stop and control valve position indication was lost, which required a manual turbine trip and closure of the main steam isolation valves.

The operators stabilized the plant in hot shutdown in the natural circulation cooling mode using the atmospheric dump valves and the auxiliary feedwater (AFW) system to control decay heat removal. The operators manually aligned the turbine driven 22 AFW pump to feed steam generators #21 and #22 since the 21 AFW pump was lost temporarily while safety buses 2A/3A were de-energized. The reactor coolant system pressure and temperature was stabilized at the no-load condition, and actions were completed to restart a charging pump, a condensate pump and a reactor coolant pump. The operators entered several technical specifications during the trip recovery.

The licensee reviewed the impact of the over-frequency condition and concluded that the reactor coolant pumps, the main turbine, and the core operated within the design limits (reference Trip Response Team Report Indian Point 2 Automatic Shutdown of December 26, 2001). The licensee completed radiation surveys and analyzed chemistry samples to verify there was no adverse impact on worker or public safety. The reactor coolant system activity remained well within the technical specification limits and was indicative of a small cladding defect that had been previously identified. The steam generator blowdown was analyzed for primary to secondary system leakage and none was found.

The inspector compared the December 26 plant response to the transient analyzed in Section 14.1.8 of the Updated Final Safety Analysis Report. The December 26 event was less severe than the Section 14.1.8 analysis in that the UFSAR analysis assumed that the reactor does not receive a direct trip from the turbine but instead is tripped when conditions in the reactor coolant system result in a trip from other signals (e.g., high pressurizer pressure). The reactor coolant system temperature and pressure conditions on December 26 remained bounded by the Section 14.1.8 analyses.

Equipment Performance - Electrical System Fault and Protective Trips

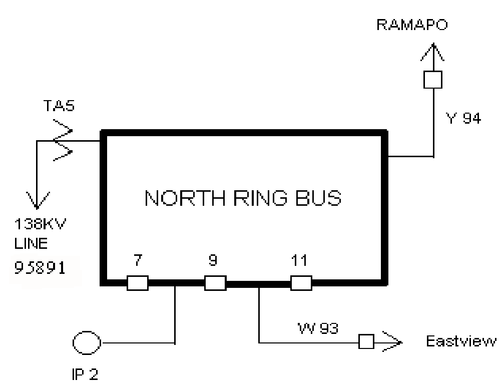
The transient electrical fault occurred on phase A of 345 KV line W93 (Eastview feeder) attached to the north ring bus in the Buchanan Switchyard. See Figure 1 for a simplified diagram of the switchyard connections. Protection relays in the offsite electrical system operated to isolate line W93 by opening breakers 9 and 11. Breaker 11 reclosed automatically as designed and the main generator continued to feed the ring bus through Breaker 7. However, a protective relay for the RAMAPO feeder misoperated and failed to block a protective trip on line Y94. This left the output of the IP2 main generator connected to the ring bus through Breaker 7 with only the loads on line 95891 fed from the ring bus via transformer TA5. The IP2 1000 MW generator output exceeded the loads fed from TA5, which caused the turbine/generator to overspeed. IP2 protective relays operated to trip the main turbine-generator on over-frequency at 62.5 hertz. The turbine trip caused the Indian Point 2 reactor to automatically shut down. Breaker 7 opened as designed following the reactor and turbine-generator trip. The Y94 protective relay that failed was subsequently found to have shorted internally, and was replaced.

The offsite power distribution personnel inspected line W93 and found it acceptable for continued service. The cause of the transient fault was not identified. For the fault that occurred in the 345 KV electrical system, the plant electrical response was as expected in accordance with the plant design (reference UFSAR Sections 8.2.2.2 and 8.2.3.4).

SEE FIGURE 1 (NEXT PAGE)

Figure 1

Buchanan 345 KV Switchyard



Direct Transfer Trip

The direct transfer trip from the Buchanan Switchyard to Indian Point 2 had been out of service prior to this event due to a degraded pilot wire cable (reference Inspection 2001-08). The direct transfer trip requires that both breakers 7 and 9 be opened to operate and thus assure the fast transfer of the 6.9 KV buses 1 through 4 from the unit auxiliary transformer to the station service transformer. Since breaker 7 did not open during the transient fault and loss of the offsite 345 KV system, the direct transfer trip function, had it been operable, would not have generated a trip signal and the turbine-generator would still have tripped on over-frequency. Thus, the inoperable direct transfer trip had no impact on the event. Nonetheless, Entergy completed a plant modification per Temporary Facility Change 2001-102 to restore the direct transfer trip function prior to synchronizing the main generator with the electrical grid. The operation of the direct trip would better assure operation of the 6.9 KV system per UFSAR Section 8.2.2.2 for generator trips other than a generator over-frequency trip. See Section 1R23 for further NRC review of the direct transfer trip.

♦ the position indication for the turbine stop and control valves was lost, which, by procedure, caused the operators to close the main steam isolation valves resulting in the loss of the main condenser. The licensee found that a fuse had blown in the indication control circuit during the electrical transient, which was replaced. The licensee also identified an intermittent ground on the indication circuit of the upper-right turbine stop/control valve. The faulty circuit (a portion of wiring) was replaced and the system was functionally tested satisfactorily (reference work order WO 01-25094).

♦ the cycling of the steam jet air ejector discharge fan and the associated valves due to intermittent spiking of the CAE radiation monitor R45 that was caused by a faulty power supply. The power supply (Victoreen 960PS Module) was replaced and the radiation monitor was functionally tested satisfactorily (reference WO 01-25087).

♦ the high pressure steam dump controller PC-404 malfunctioned on December 27 when attempting to use the high pressure steam dump rather than the atmospheric steam dump (CR# 200112953). The controller had previously malfunctioned during a startup on 11/4/01 (CR# 200110770). The licensee replaced the Foxboro 62H-5E controller (reference WO 01-24515).

The operators also initiated condition reports for other equipment that malfunctioned during and after the trip. Those equipment issues involved a number of process radiation monitors that malfunctioned, letdown pressure control valve PCV-135 erratic performance in automatic, slow closing of the 21 main boiler feedwater pump discharge valve, high vibrations on the 24 reactor coolant pump upon restart post trip, and inspection of secondary plant pipe hangers as a precaution from the thermal and hydraulic transient on the condensate and feedwater systems.

Personnel Performance

The inspector observed that operators appropriately implemented emergency operating procedures E-0, “Reactor Trip and Safety Injection,” and ES-0.1, “Post-Trip Recovery.” Operators manually restored electrical power in a timely manner (10 minutes) to safeguards buses 2A and 3A, restored a charging pump in a timely manner (8 minutes after the trip), maintained auxiliary feedwater flow to all four steam generators, and appropriately closed the main steam isolation valves upon the loss of turbine stop valve and control valve position indications. Abnormal operating procedure (AOI) 3.4, “Uncontrolled Reactivity Addition”, use was appropriate for loss of electrical power to the individual rod position indicators. Individual rod position indication power was restored within 10 minutes after the trip. Operating crews appropriately used shift briefings during transition between E-0 and ES-0.1, and the crew appropriately used the off-going shift personnel to verify technical specification requirements and collect plant data for the post-trip review.

Licensee Response and Assessments

The licensee completed a post trip review of the December 26, 2001, transient in accordance with OAD 23, Post Trip Review. The inspector observed Entergy’s site nuclear safety committee (SNSC) review of the trip response report on December 27, 2001. The committee appropriately evaluated the investigation into the cause of the trip and had a number of followup items. The SNSC ensured prior to plant restart that Con Edison evaluated and understood the 345 KV disturbance and took corrective actions to better assure the availability of the electrical distribution system. The inspector confirmed that the cause and corrective actions were completed prior to restart.

In accordance with the NRC Manual Chapters 0609, “Significance Determination Process,” and 0610*, “Power Reactor Inspection Reports,” this issue was determined to be more that minor because a reactor trip is a transient initiator and plant transient with electrical complications could be a significant safety concern if the lost safety equipment was not readily recovered. When evaluated in accordance with the SDP Phase 1, the issue was considered to be of very low safety significance since there was no impact on the plant safety barriers and the impact on mitigating safety equipment availability was minimal. (GREEN)

.3 Plant Startup

a. Inspection Scope (71111.14)

The inspector observed crew briefings and performance during the reactor start-up on December 27 and 28, 2001. The reactor was made critical at 2:35 p.m. on December 28, 2001. The inspection scope also evaluated Entergy’s evaluation and actions in response to a failed primary water flow transmitter (CR 200112998) during the reactor startup.

b. Issues and Findings

No significant findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

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 IP2's Individual Plant Examination. The regulatory references 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 activity was evaluated: PMT-0124681, 21 Auxiliary Feedwater Pump FCV-406A (CR 200111489, CR 200111587).

b. Issues and Findings

No significant findings were identified.

1R22 Surveillance Testing

.1 Routine Surveillance Test Observations

a. Inspection Scope (71111.22)

The inspector reviewed surveillance test procedures and observed testing activities to assess whether 1) the test preconditioned the component tested, 2) the effect of the testing was adequately addressed 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 surveillances observed were based upon risk significant components as identified in the Indian Point 2 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 Specifications 6.8.1.a. The following test activities were reviewed:

- PT-M70, Monthly Control Rod Exercise Test, December 13, 2001
- Map 15FC13, Power Distribution and Hot Channel Factor Determination at 99.8% power and 10150.97 MWD/MTU, November 13, 2001
- Map 15FC14, Power Distribution and Hot Channel Factor Determination at 99.9% power and 11135.95 MWD/MTU, December 11, 2001
- PT-Q58, Steam Generator Level Bistable Functional Test, December 14, 2001

- PI-A1A, Special Nuclear Material Inventory, December 15, 2001

For core power distribution measurements, the inspector reviewed the licensee's actions to trend the Cycle 15 core peaking factors, including the maximum nuclear enthalpy rise hot channel factor ($F_{\Delta}H$). The inspection verified that the hot channel factors remained within the Technical Specification 3.10.2 limits.

b. Issues and Findings

No significant findings were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope (71111.23A)

The inspector reviewed the temporary facility change (TFC) 2001-102, Replacement Trip Transfer from Buchanan, and the associated safety evaluation, SE 01-916-TM-00-RS, Restoration of Direct Trip from Buchanan to IP2, to verify that the facility change did not impact safety system operability and the licensee requirements, and that the change did not violate 10 CFR 50.59. The inspector also verified that the activities were completed in accordance with the licensee's controls for installation.

The direct transfer trip from the Buchanan Switchyard had been out of service due to two degraded pilot wires (insufficient insulation resistance). The licensee completed a temporary modification to restore the direct transfer trip function by using two existing spare wires to replace the degraded wires. The modification also disabled the remote operation from IP2 control room of the motor operated disconnect (MOD) switch MO F 7-9 (the MOD would be operated locally at the switchyard and position indication of the disconnect switch remained available in the control room). The licensee changed procedures SOP 26.4 (temporary procedure change TPC 01-248) and SOP 27.1.1 (TPC 01-249) to allow local operation of the MOD in the switchyard by the District Operator. The inspector verified the wiring changes in the IP2 control room were completed as described by TFC 2001-102. The inspector also reviewed the result of the post-modification testing (reference WO 01-25100).

b. Issues and Findings

No significant findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspector conducted an in-office review of licensee submitted changes for the emergency plan-related documents listed below to determine if the changes decreased the effectiveness of the plan (10 CFR 50.54(q)). A thorough review is conducted for documents related to the risk significant planning standards (RSPS), such as classifications, notifications and protective action recommendations. A cursory review was conducted for non-RSPS documents. The submitted and reviewed documents were:

Emergency Plan for Indian Point 1 & 2, Rev 01-02
IP-1023, Operations Support Center, Rev 16
IP-1025, Handling Fire Department Personnel Fighting Fires in the Controlled Area, Canceled
IP-1027, Personnel Accountability and Evacuation, Rev 14
IP-1050, Security, Rev 1

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 and inspected 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 the routine radiologically-controlled-area (RCA) control points on a daily basis to verify compliance with requirements for RCA entry and exit, dosimetry placement, and issuance and use of electronic dosimeters. On November 20 and 21, the inspector toured and observed activities on the 80-foot elevation of Unit 2's primary auxiliary building and on the fuel handling floor of Unit 1. The inspector also toured outside areas within the protected area. During these observations and tours, the inspector reviewed for regulatory compliance 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.

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

- Procedure SAO-302, Rev. 17, Radiation work permits (RWP) program
- Procedure HP-SQ-3.012, Rev. 17, Airborne radioactivity sampling and analysis
- Procedure HP-SQ-3.109, Rev. 27, Control of high radiation, locked high radiation, special locked high radiation, and very high radiation areas
- RWP 010251, Rev. 03, Unit 2 mid cycle outage evolutions; associated pre-job briefing documentation and radiological surveys
- RWP 010252, Rev. 02, Unit 2 transfer canal and cavity liner work; associated pre-job briefing documentation, radiological surveys, and daily derived air concentration (DAC)-hour logs
- Site wide self-assessment, radiological protection, October 15 - 26, 2001
- Assessment report no. 01-AR-29-RP, Nuclear quality assurance independent oversight program, radiation protection, August 27 - 31, 2001
- 10 Code of Federal Regulations (CFR) 50.75(g) file, Record keeping for decommissioning planning

The inspection included a review of two Condition Reports (CRs)(i.e., CR 200110390 and 200111323) for the appropriateness and adequacy of event categorization, immediate corrective action, corrective action to prevent recurrence, and timeliness of corrective action.

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 findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope (71121.03)

The inspector reviewed the program for health physics instrumentation to determine the operability of the instrumentation and the accuracy of their readings.

During plant tours, the inspector reviewed field instrumentation utilized by health physics technicians and plant workers to measure radioactivity and radiation levels. The instrumentation included portable field survey instruments, hand-held contamination frisking instruments, and continuous air monitors. The inspector conducted a review of the instruments observed in the toured areas. This review included verification of current calibrations, of appropriate source checks, and of proper function. The inspector also reviewed activities in the health physics counting room and in the dosimetry office. The inspector evaluated the following procedures and calibration records for regulatory compliance and adequacy:

- Procedure DOS-6.118, Rev. 3, Operation of the Merlin-Gerin automatic dosimetry system

- Procedure DOS-6.125, Rev. 4, Calibration of the Merlin-Gerin electronic dosimeter and CDM21 calibrator using windows
- Procedure DOS-6.205, Rev. 7, Technical instructions for operation of the Canberra Fastscan whole-body counter
- Procedure HP-SQ-3.701, Rev. 11, Health physics count room standard practices
- Procedure HP-9.019, Rev. 7, Operation of the Eberline BC-4
- Procedure HP-9.020, Rev. 3, Calibration of Eberline BC-4
- Procedure HP-9.024, Rev. 5, Calibration of Eberline Model SAC-4 alpha counter
- Procedure HP-9.580, Rev. 4, Calibration of Tennelec LB5100-W
- Recent calibration records for whole-body counters and for electronic dosimeters

The review was against criteria contained in 10 CFR 20.1501, 10 CFR 20 Subpart H, site Technical Specifications, and site procedures.

b. Issues and Findings

No findings of significance were identified.

2PS1 Gaseous and Liquid Effluents

a. Inspection Scope (71122.01)

The requirements for radioactive effluent controls are specified in the Technical Specifications and the Offsite Dose Calculation Manual (TS/ODCM). The inspector reviewed the following documents to evaluate the effectiveness of the licensee’s radioactive gaseous and liquid effluent control programs:

- the 1999 and 2000 Radiological Annual Effluent Release Reports including projected public dose assessments;
- review of the ODCM (Revision 6, October 28, 1999), including technical justifications for ODCM changes made;
- selected 2001 analytical results for charcoal cartridge, particulate filter, and noble gas samples;
- implementation of the compensatory sampling and analysis program when the effluent radiation monitoring system (RMS) was out of service;
- selected 2000 and 2001 radioactive liquid and gaseous release permits;
- associated effluent control procedures, including analytical laboratory procedures;
- implementation of the NRC Bulletin 80-10 sampling program;
- calibration results for chemistry laboratory measurement equipment (gamma and liquid scintillation counters);
- implementation of the measurement laboratory quality control program, including effluent intra-laboratory and inter-laboratory comparisons and control charts;
- 2001 Chemistry self-assessment;
- the following Condition Reports and associated corrective actions: 200002197, March 28, 2000; 200002549, April 11, 2000; 200109476, October, 3, 2001; 200109778, October 12, 2001; and 200112261, December 12, 2001.

- the 2001 NQA Audit (Audit No. 00-03-F, January 17, 2001) of implementation of the radioactive liquid and gaseous effluent control program and the ODCM;
- the most recent Channel Calibration and Channel Functional Test results for the radioactive liquid and gaseous effluent radiation monitoring system (RMS) and its flow measurement device as listed in Tables 4.10-2 and 4.10-4 of the Technical Specifications (TS), as listed below:

  Unit 1 RMS:
  - Service/River Water Liquid Radiation Monitor (R-51);
  - Liquid Discharge Radiation Monitor (R-54);
  - Secondary Boiler Blowdown Effluent Line (R-52);
  - Sphere Foundation Sump Discharge Monitor (R-62); and
  - Stack Vent Noble Gas Monitor (R-60)

  Unit 2 RMS:
  - Waste Disposal Liquid Effluent Line (R-48);
  - Component Cooling Water Radiation Monitor (R-47);
  - Steam Generator Blowdown Effluent Line (R-49);
  - Service Water System Effluent Line Monitors (R-46/53);
  - Component Cooling Service Water Heat Exchangers (R-39/40);
  - Plant Vent Noble Gas Monitors (R-44 and R-27); and
  - Large Gas Decay Holding Tank Monitor (R-50)

  Units 1 & 2 Flow Rate Measurement Devices:
  - Stack Vent Flow Rate Monitor;
  - Plant Vent Flow Rate Monitor;
  - Liquid Effluent Line Flow Rate Monitor; and
  - Steam Generator Blowdown Effluent Line

- the most recent surveillance testing results (visual inspection, delta P, in-place testings for HEPA and charcoal filters, air capacity test, and laboratory test for iodine collection efficiency) for the following air treatment systems listed in the following TS: TS 4.5.D, Containment Air Filtration System; TS 4.5.E, Control Room Air Filtration System; TS 4.5.F, Fuel Storage Building Air Filtration System; and TS 4.5.G, Post-Accident Containment Venting System.

- the review of the Response Letter to the NRC Generic Letter 99-02, “Laboratory Testing of Nuclear-Grade Activated Charcoal.”

The inspector also toured and observed the following activities to evaluate the effectiveness of the licensee’s radioactive gaseous and liquid effluent control programs.

- walk down to determine the availability of radioactive liquid/gaseous effluent RMS and to determine the equipment material condition;
- walk down to determine the operability of air cleaning systems and to determine the equipment material condition; and
- the observation of radioactive filter and charcoal cartridge sampling and preparation for gamma spectrometry measurements.

b. Issues and 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 inspector reviewed the following documents to ensure the licensee met all requirements of the performance indicator from the third quarter 2000 to the third quarter 2001 for all units:

- 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; and,
- associated procedures.

The information contained in these records was compared against the criteria contained in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 1, to verify that all conditions that met the NEI criteria were recognized, identified, and reported as a Performance Indicator occurrence.

b. Issues and Findings

No significance findings were identified.

4OA2 Cross Cutting Issues

a. Inspection Scope (71153)

The inspector evaluated the effectiveness and timeliness of corrective actions associated with instrument errors impacting operation of the overpressure protection system (OPS) and the attended operator controls of reactor coolant system conditions. Conditions reports (CRs) reviewed included the following: CR 199904072, 199908215, 200004598, 200104118, and 200105283.

b. Issues and Findings

No Color The licensee's corrective actions in response to condition report 200004598 were untimely and did not preclude plant operation in violation of TS figure 3.1.A-2. Condition report 200004598 was initiated on June 16, 2000, and identified that plant procedures did not address instrument uncertainty as described in the TS bases to ensure the limits for the power operated relief valve setpoints and the TS heatup and cooldown curves were met. Additionally, the problem analysis failed to consider the implication on the associated TS curves when overpressure protection system (OPS) is not considered operable and no reactor coolant system vent space exists. The corrective actions in response to this CR failed to preclude operators from violating TS figure 3.1.A-2 on July 2, August 3, and November 30, 2000.

The failure to take effective corrective actions and perform appropriate extent of condition reviews for other TS curves associated with the overpressure protection system is considered a violation of 10 CFR 50 Appendix B, Criterion XVI. This issue had low actual safety significance because no consequence to the reactor coolant system pressure boundary occurred and procedural actions had been completed for the above performance issues. 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 50-247/01-11-02)**

4OA3 Inspection Item Followup

.1 (Closed) **URI 05000247/2001-006-002** pertaining to the licensee's accounting of instrument uncertainties associated with the overpressure protection system relief valve setpoints. The item was unresolved pending NRC review of past reactor coolant system shutdown pressure and temperature conditions and verification that the power operated relief valve (PORV) setpoints were adequate when instrument inaccuracies were accounted for in accordance with Technical Specification Figures 3.1.A-1 and 4.3.1.

Initially, the licensee concluded that for approximately 2,714 hours of plant shutdown operations, the reactor coolant system temperature and pressure would have exceeded TS 3.1.A-1 when the maximum instrument uncertainties were considered. This initial determination was incorrect since the licensee had used wide range reactor coolant system pressure indications that had an error of +/-117 psig. The actual instruments used in the PORV setpoints are narrow range instruments (PT-413, 433, 443) with an instrument error of +/-28.5 psig. The licensee re-evaluated past data and concluded that the plant conditions did not exceed the PORV setpoints with the correct maximum instrument error. Notwithstanding, in August 2001, the inspector questioned licensee engineering personnel on the acceptability of meeting heat-up, cool-down and OPS operability TS curves that also do not account for instrument errors. The licensee reviewed plant operations for the previous three years. On October 23, 2001, Entergy determined that the plant operated outside the requirements of TS 3.1.A. 4 and TS Figure 3.1.A-2 on four periods in the year 2000 with a total exposure of approximately 49 hours. This was reported to the NRC via licensee event report 2001-005.

GREEN The plant operated in violation of the pressure and temperature limits in TS Figure 3.1.A-2 on four occasions in the year 2000. The cause was a failure to have operations procedures that account for reactor coolant system temperature and pressurizer level instrument errors to ensure that operators would not exceed the requirements of TS 3.1.A-2 when the OPS was inoperable.

This issue was evaluated in the SDP process (Manual Chapter 0609 Appendix G). Findings involving non-compliance with low temperature overpressure protection required a phase 2 analysis. During the periods when the facility operated outside TS Figure 3.1.A-2 all appropriate administrative controls to limit the potential for unwarranted heat-up or mass addition to the reactor coolant system were implemented by the operators. The consequence of this error was to reduce the required operator response time to less than the 10 minutes previously approved in the licensing basis. A reactor coolant system overpressure event did not occur during these times (e.g., there was no inadvertent start of a safety injection pump or reactor coolant pump). 10 CFR 50 Appendix G limits were not challenged. During two of the four times, the reactor coolant system was depressurized. This issue was found to have very low safety significance, since no challenge to reactor coolant system pressure existed, and administrative controls of pumps were properly adhered to by operators.

TS 6.8.1.a, requires, in part, written procedures to be implemented for activities referenced in Appendix "A" of regulatory Guide 1.33 revision 2. Appendix "A" includes the requirements for items "2j", "Hot Standby to Cold shutdown and "2a", "Cold Shutdown to Hot Standby." The inspector identified the following:

- Plant Operating Procedure (POP) 1.1, "Plant Restoration from Cold Shutdown to Hot Shutdown Conditions, and POP 3.3, "Plant Cooldown" failed to provide administrative controls to ensure that TS figures 3.1.A-2 and 3.1.A-3 would not be violated when OPS is not operable and no reactor coolant system vent opening is available. The specific administrative controls concern the accounting for instrument errors associated with reactor coolant system temperature and pressurizer level. Failure to have administrative controls resulted in the operators exceeding TS figure 3.1.A-2 on February 16, July 2, August 3, and November 30, 2000.

The failure to adhere to TS Figure 3.1.A-2 on multiple occasions is a violation of TS 3.1.A.4, and the failure to implement adequate procedures is considered a violation of TS 6.8.1.a. These violations are treated as Non-cited violations, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000 (65 FR 25368). The licensee entered these issues in condition report 200105283. **(NCV 50-247/01-11-03)**

4OA4 <u>Licensee Event Report Reviews</u>

.1 <u>(Closed) LER 05000247/2001-05:</u> Overpressure Protection System. This LER is closed as is further documented in report detail 4OA3.

4OA6 Meetings

Exit Meeting Summary

On January 9, 2002 , the inspector presented the inspection results to Mr. L. Temple 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**

D. Agrest	Health Physics Technician
P. Asendorf	Security Manager
F. Dacimo	Vice President, Operations
M. Donegan	Health Physics Manager
N. Ertle	I&C Engineer
R. Fucheck	Health Physics Supervisor
A. Ginsberg	Technical Specialist, Chemistry
L. Glander	Supervisor, Radiological Support
T.R. Jones	Senior Engineer, Nuclear Safety and Licensing
K. Kuran	Specialist, System Engineering
R. Louie	Senior Engineer, Nuclear Safety and Licensing
E. Libby	Licensed Operator Instructor
R. Mages	Senior Radiation Protection Specialist
R. Majes	Radiological Support Health Physicist
T. McCafferty	System Engineering Manager
J. McCann	Manager, Nuclear Safety and Licensing
M. Miele	Radiation Protection Department Manager
M. Miller	Manager, Generation Support
D. Morris	General Manager, Nuclear Quality Assurance and Oversight
V. Nutter	Radiation Support Manager
W. Osmin	Reactor Engineer
V. Nutter	Radiological Support Manager
G. Schwartz	Director of Engineering
D. Smith	Rad Assessor, NQA&O
P. Rubin	Operations Manager
R. Sutton	Senior Engineer, SL-1 Team Leader
L. Temple	Plant Manager
M. Vaseley	System Engineer Supervisor
J. Ventosa	Engineering Manager
T. Wadell	Maintenance Manager
E. Woody	I&C Manager

b. List of Items Opened, Closed, and Discussed

Opened and Closed During this Inspection

50-247/01-11-01	NCV	On December 17, 2001, the operators failed to place the Mode switch to AUTO. The failure to perform Step 4.3.16.(4) resulted in the inadvertent dilution of the RCS by an additional 6 gallons, which was classified as a reactivity management event. The failure to adhere to a procedure is being treated as a non-cited violation.
50-247/01-11-02	NCV	Failure to perform effective corrective actions associated with overpressure protection system contrary to 10 CFR 50 Appendix B, Criterion XVI
50-247/01-11-03	NCV	Multiple failure to adhere to TS figure 3.1.A-2 in the year 2000

Closed

50-247/01-06-02	URI	Instrument error associated with overpressure protection system relief valve setpoints
50-247/2001-05	LER	Overpressure Protection Errors

c. List of Documents Reviewed for Maintenance Rule Inspection

Procedures

SAO-250, Indian Point Preventive Maintenance Program, Revision 10
SAO-161, Operational Risk Management, Revision 1
SE-SQ-12.311, Preventive Maintenance Basis Evaluation Program, Revision 4
MAD-17, Preventive Maintenance Procedure, Revision 12
Surveillance Test PT-Q34A, Auxiliary Feedwater Pump 22 Valve Strokes.

Reports

Maintenance Rule Periodic Assessment, July 26, 2000
Maintenance Rule Quarterly Report, Third Quarter, 2001
System Health Report, Auxiliary Feedwater System {(a)(2)}, 3rd Quarter, 2001
System Health Report, CVCS {(a)(1)}, 3rd Quarter, 2001
System Health Report, 480V {(a)(2)}, 3rd Quarter, 2001
System Health Report, CCR HVAC System {(a)(1)}, 3rd Quarter, 2001
System Health Report, SISA/ESFAS {(a)(1)}, 3rd Quarter, 2001
System Health Report, EDG HVAC {(a)(1)}, 3rd Quarter, 2001

Condition Reports

200100493	200101187	200101366	200105477	200105960	200106950
200109066	200109633	200109839	200110097	200110289	200110290
200110293	200110939				

d. **List of Acronyms**

AFW	auxiliary feedwater
AOI	Abnormal Operating Instruction
CAE	condensor air ejector
CFR	Code of Federal Regulations
CR	Condition Report
CVCS	chemical and volume control system
DAC	derived air concentration
DBT	design basis threat
EDG	emergency diesel generator
FOSAR	foreign object research and retrieval
gpd	gallons per day
HRA	High Radiation Area
KV	kilovolt
LHRA	Locked High Radiation Area
LLD	lower limits of detectability
MR	maintenance rule
NCV	non-cited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OAD	operations administrative directive
ODCM	Offsite Dose Calculation Manual
OS	Occupational Safety
PARS	publicly available records
PCM	percent millirho
PCV	pressure control valve
PMT	post maintenance test
PORV	power operated relief valve
RC S	reactor coolant system
RCA	Radiologically Controlled Area
RMS	Radiation Monitoring System
RSPS	Risk Significant Planning Standard
SAO	station administrative order
SCBA	self-contained breathing apparatus
SISA	safety injection system actuation
SNSC	site nuclear safety committee
SOP	station operating procedure
SSC	structure, system and component
TFC	temporary facility change
TPC	temporary procedure change
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report