U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-286
License No.	DPR-64
Report No.	50-286/99-07
Licensee:	New York Power Authority
Facility:	Indian Point 3 Nuclear Power Plant
Location:	P.O. Box 215 Buchanan, New York 10511
Dates:	July 29 - September 13, 1999
Inspectors:	Peter Drysdale, Senior Resident Inspector Laura Dudes, Resident Inspector Kenneth Kolaczyk, Reactor Engineer (8/12) David Cullison, Reactor Engineer (8/22 - 8/24) Blake Welling, Resident Inspector, Peach Bottom (8/30-9/2)
Approved by:	John Rogge, Chief Projects Branch 2 Division of Reactor Projects

EXECUTIVE SUMMARY

Indian Point 3 Nuclear Power Plant
NRC Integrated Inspection Report No. 50-286/99-07

This inspection included aspects of licensee operations, maintenance, and engineering. The report covered a six-week period of resident inspections, and included inspections by region-based specialists.

Operations:

The plant responded as designed following the failure of the 34 instrument bus on August 12, 1999. However, the plant transient following the reactor trip was complicated, and operator performance in response to the trip was mixed. There were important equipment losses/responses following loss of the 34 instrument bus that were undetected for a period of time, and that operators were not alerted to by the existing procedures. Also, the operators did not appear to be fully cognizant of the circuitry of the high pressure steam dump valves which in this scenario rendered them inoperable due to a loss of signal to the controller. Further, although operations management considered that operator performance was acceptable, very little information was available from interviews to support this conclusion (Section O1.1).

The PTRG's initial response to this event was poor with respect to NYPA's administrative guidance for post-transient evaluations. The PTRG was slow to organize, to develop a plan with team member assignments, and to initiate effective data gathering. The PTRG also did not effectively coordinate assignments for operations or engineering to assist in developing a comprehensive timeline, or to evaluate plant and operator responses. Aggressive management direction and oversight was necessary for the PTRG to develop a final end product with sufficient analysis and recommendations to afford site management with a sound safety-basis for restarting the plant (Section O1.1).

The plant startup on August 13, 1999, was well controlled and had a good level of management oversight. The operators performed well, and maintained a strong emphasis on reactivity management with good command and control during the reactor startup (Section O1.2).

The licensee was unnecessarily challenged by safety-related and nonsafety-related secondary equipment during the plant transient on August 12. A third incident of degraded auxiliary boiler feed pump packing was observed during the reactor trip transient. Also, a carbon dioxide discharge onto the main boiler feedwater pumps and a failure of a secondary steam supply valve provided minor distractions to the operations crew coping with the transient (Section O2.1).

The off-normal operating procedure for the loss of the 34 instrument bus did not provide sufficient guidance to the reactor operators for how to manage secondary pressure control when this instrument bus is lost. As a result, some challenges to the operators and to plant equipment were noted that complicated a transient on August 12, 1999. In order to disseminate the lessons learned, the operations manger issued a shift order that contained specific actions for operators, even though the licensee's operations administrative procedure did not allow this practice. (Section O3.1).

A detailed and thorough licensee-performed risk assessment of the RO-10 refueling outage schedule resulted in a number of improvements to the schedule, thereby increasing equipment redundancy for key safety functions (Section O8.1)

Maintenance:

Maintenance activities observed were conducted satisfactorily and in accordance with applicable maintenance and administrative procedures. The licensee appropriately monitored performance of equipment within the scope of the maintenance rule (Section M1.1).

Surveillance tests were conducted appropriately and in accordance with procedural and administrative requirements. Good coordination and communication with the control room were maintained during performance of the observed surveillances. Test instrumentation was within calibration and the test acceptance criteria were achieved (Section M1.2).

The performance of the Appendix R diesel generator monthly surveillance test was good. Procedures and self checking techniques by the test performers were used effectively and in accordance with licensee procedures. However, neither the test or operating procedure verified the correct speed setting on the engine mechanical governor. The configuration control verification for the diesel was not thorough and may not have prevented inadvertent tripping of the Appendix R diesel when called upon for service if the governor's speed setting had been inadvertently altered. The licensee appropriately planned to revise the system prerequisite check-off list to verify the speed setting. Some poor communication between system engineering, planning, and operations was noted as problem identification tags remained on the engine control panel even though the problems had been reviewed and deemed acceptable by both planning and engineering (Section M1.3).

The licensee did not take adequate corrective actions to identify the root cause or to prevent a significant accumulation of water in the bottom of the 32 emergency diesel generator (EDG) fuel oil storage tank. Three prior instances of water accumulation were identified by the licensee and were entered into their corrective action system. However, the corrective actions in the licensee's October 1998 action plan were not complete and did not prevent the recurrence of a significant condition adverse to quality. That condition could have resulted in a common mode failure for all three EDGs due to a fuel transfer system design that could have transferred the water to each diesel generator day tank. This is considered to be a severity level IV violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action;" however, it will be regarded as a non-cited violation in accordance with Appendix C of the NRC Enforcement Policy (NCV 50-286/99002-01) (Section M2.1).

The licensee's preventive maintenance did not include a sufficient post-maintenance test to provide an adequate basis for operability of the 31 auxiliary boiler feedwater pump. The pump was later declared inoperable due to motor vibration data that was above administrative limits. The licensee's maintenance and test procedures were revised to require appropriate evaluation and testing (Section M2.2).

Engineering:

Engineering evaluation of the flow requirements described in the licensee's emergency operating procedures was not translated into the acceptance criteria of a service water flow performance test. Specifically, the back pressure resulting from the addition of a service water pump onto the non-essential header was not accounted for in the acceptance criteria nor the design basis calculation for the system (NCV 50-286/99007-02) (Section E1.1)

NYPA reactor engineering demonstrated a proactive response to a 10 CFR Part 21 Notification by Rochester Gas & Electric by evaluating its potential impact on IP3, and by identifying errors and initiating corrections through Westinghouse to the existing design basis analysis of record for a main steam line break inside containment (Section E8.2).

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ATTACHMENTS

Report Details

SUMMARY OF PLANT STATUS

Indian Point 3 operated at full power at the beginning of the inspection period on July 29, 1999. On August 12, the reactor tripped following a loss of the 34 instrument bus. Following a brief forced outage the reactor was brought critical on August 13, and full power was achieved on August 15. The reactor remained at full power until the licensee began a refueling "coastdown" on August 22. The licensee commenced a controlled power reduction from 87% on September 10, achieved cold shutdown on September 11, and began the refueling outage.

I. OPERATIONS

O1 Conduct of Operations

O1.1 Licensee Response to the Reactor Trip

a. Inspection Scope (71707)

The inspector reviewed the licensee's response and follow-up assessment after a reactor trip on August 12, 1999. This included a review of the sequence of events, the alarm response printouts, and a verification that the plant responded as designed following the failure of the 34 instrument bus.

b. Observations and Findings

At 4:07 a.m. on August 12, 1999, a power resistor failed in the static invertor for the 34 instrument bus which disabled the power supply to the bus. That instrument bus does not have a feature to automatically transfer the power supply to an alternate source, and the bus de-energized. Immediately following the loss of the 34 bus, a turbine runback occurred due to the loss of the reactor coolant system (RCS) temperature averaging circuit input to channel 3 of the reactor protection system (RPS). This satisfied the RPS circuitry logic of one-out-of-four overpower delta temperature for a turbine runback. Loss of the instrument bus also caused a loss of power to all four level controllers in the steam generator water level control system, and caused all four feedwater regulating valves (FRVs) to fail closed. The closure of all four FRVs and the rapid turbine power decrease resulted in a rapid decrease of all steam generator levels. A low level in the 33 SG caused the reactor to trip. Both reactor trip breakers opened normally, and all control rods fully inserted following the trip signal.

The turbine runback also caused an increase in RCS temperature, and the resulting increase in pressurizer pressure reached the actuation setpoint for opening a power-operated relief valve (PORV). The second pressurizer PORV did not open at the elevated pressure because control power was not available due to the loss of the instrument bus.

Control power to the high pressure steam dump valves was also disabled by the loss of the bus, and those valves were not available to relieve secondary plant pressure. Within approximately three minutes after the reactor trip, pressure in the 32 steam generator reached the lift setpoint for one of the safety relief valves (SRVs). The atmospheric relief valve (ARV) for that generator did not lift because control power was also lost with the instrument bus. Control power for the 31 steam generator ARV was also disabled, and the ARV was not available to relieve high pressure in the 32 generator. The ARVs in the 33 and 34 steam generators also lifted in response to the high secondary plant pressure; however, the 32 steam generator SRV lifted three times within an approximate 1-1/2 hour time period after the reactor trip. At that time, operators lowered the 34 ARV lift setpoint to prevent further actuations of the 32 SRV. Shortly thereafter, the instrument bus was repaired and returned to service, and plant temperatures and pressures were stabilized following restoration of the steam dump valves.

Operator Response

The initial operator response to the reactor trip and the subsequent plant transient was proper and in accordance with existing procedures to stabilize plant conditions. However, for more than an hour following the trip, some errors were made that needlessly complicated the plant recovery. Specifically, the operators did not closely monitor plant temperature and steam generator pressure, and failed to note a steady increase in those parameters. The temperature and pressure increase was not stopped until the 32 SRV opened. This event could have been avoided if operators promptly recognized the secondary plant pressure and temperature increase, and used the atmospheric steam dumps to keep steam generator pressure below the SRV lift setpoint. The operators apparently did not anticipate the ARVs lifting, and waited too long to adjust the ARV setpoint, i.e., until after the 32 SRV lifted for the third time.

Post-Transient Review Group (PTRG) Performance

Approximately four hours after the reactor trip, the licensee assembled a post-transient review group (PTRG) to collect data and relevant information for analyzing the transient. Under the existing administrative guidance, the PTRG was assigned to determine the initiating cause of the transient, analyze the plant response, and recommend necessary corrective actions prior to restart. The PTRG was also responsible for developing a detailed sequence of events (i.e., an event timeline) that could depict the chronology of significant operator and equipment responses. The PTRG was not chartered to function as an outage management group with the authority to direct station activities during the shutdown. This function remained with senior station management.

The inspectors noted that the licensee had difficulty assembling PTRG team members on short notice following the trip. A temporary group leader was initially assigned who did not have the desired qualifications, and additional time was needed to assign a qualified permanent group leader. Once assembled, the PTRG initially experienced internal communication and coordination difficulties, and was not effective in requesting or coordinating activities in operations and engineering to analyze the transient, to reconstruct a detailed sequence of events, or to evaluate plant and operator performance. The PTRG also experienced difficulty in obtaining plant data that was needed to reconstruct and understand the trip and the plant response. The plant computer was apparently overloaded by numerous queries from operations and engineering personnel for purposes not directly related to the PTRG's primary function, and caused significant delays in getting data to the PTRG. Some PTRG members expressed concerns to the group leader that they apparently did not have a high enough priority to access the plant computer. Consequently, individual PTRG members attempted to analyze raw data independent from operations and engineering. Strip chart records from the control room were available for PTRG review, but it became necessary for the team to produce a hand-drawn plot of steam generator pressure and T_{ave} to fully represent the relationship between these parameters during the transient conditions. The PTRG also did not request engineering and operations the analysis of specific equipment performance, but attempted to analyze performance on its own, and consequently was slow to put together a comprehensive sequence of events that depicted the plant and operator response to the trip and transient. The PTRG did not get design engineering involved to evaluate the SRV and ARV responses during the post-trip review until the day after the trip.

Communications between the operators, operations management, and the PTRG were ineffective in key areas necessary to understand plant equipment and operator performance. For example, 1) the fact that a pressurizer power-operated relief valve (PORV) had lifted after the trip was not communicated to the operations manager or to the PTRG for approximately 10 hours; 2) there was not full agreement between the PTRG members over whether or not the operators knew that two ARVs were disabled after the 34 instrument bus was lost. The post-trip recollection sheets, required to be completed by operators soon after the trip, were incomplete and not useful to the PTRG for fully understanding the transient and the operators response. The PTRG did not interview the plant operators soon after the trip since most operators departed the site at the end of their shift before the PTRG started to gather information; 3) details of how the operators followed the off-normal operating procedure (ONOP) in managing secondary plant pressure was somewhat vague to the PTRG. The ONOP directed operators to reduce secondary pressure by reducing T_{ave}, but did not direct operators to use the ARVs when T_{ave} could no longer be reduced through other means that may have been available if any of the other three instrument busses had been lost (see section O3.1).

As a result, the initial PTRG briefings to senior plant management were missing essential information from the event timeline that could have afforded plant management an early understanding of the transient with sufficient bases to evaluate the plant's readiness for restart. Multiple briefings were necessary before a complete timeline was constructed. Vigerous prompting and direction by NYPA management became necessary to direct the PTRG to perform a more rigorous analysis of the data and to assure site management that the plant responded in accordance with its design, and that operators were appropriately briefed on the lessons learned from this event.

The NRC remains concerned about the licensee's inability to effectively organize the necessary resources following the reactor trip on August 12, and to readily initiate and conduct an effective evaluation of plant and operator performance sufficient for plant management to make the appropriate decisions to approve a plant restart without vigorous prompting.

c. Conclusions

The plant responded as designed following the failure of the 34 instrument bus on August 12, 1999. However, the plant transient following the reactor trip was complicated, and operator performance in response to the trip was mixed. There were important equipment losses/responses following loss of the 34 instrument bus that were undetected for a period of time, and that operators were not alerted to by the existing procedures. Also, the operators did not appear to be fully cognizant of the circuitry of the high pressure steam dump valves which in this scenario rendered them inoperable due to a loss of signal to the controller. Further, although operations management considered that operator performance was acceptable, very little information was available from interviews to support this conclusion.

The PTRG's initial response to this event was poor with respect to NYPA's administrative guidance for post-transient evaluations. The PTRG was slow to organize, to develop a plan with team member assignments, and to initiate effective data gathering. The PTRG also did not effectively coordinate assignments for operations or engineering to assist in developing a comprehensive timeline, or to evaluate plant and operator responses. Aggressive management direction and oversight was necessary for the PTRG to develop a final end product with sufficient analysis and recommendations to afford site management with a sound safety-basis for restarting the plant.

O1.2 Post-Trip Startup Observations

a. Inspection Scope (71707)

The inspectors observed control room activities during the post-trip startup on August 13, 1999.

b. Observations and Findings

On August 13, 1999, the inspector attended the pre-start up brief in the control room. The inspector noted the control room supervisor provided thorough information and emphasized reactivity management throughout the evolution. The licensee also discussed deviation event reports (DERs) that had been written during the last startup to remind the operators of items that may develop during the startup evolution. Also, the licensee discussed recent industry-wide operating events that occurred during plant startups. The inspector observed that the briefs for this evolution were performed well and with a high quality content.

The inspector observed the control room operators when they pulled the shutdown and control rod banks to the critical rod position. During the evolution, the operators maintained good control decorum and placed good emphasis on reactivity management. The reactor was declared critical at 9:58 p.m. on August 13.

c. Conclusions

The plant startup on August 13, 1999 was well controlled and had a good level of management oversight. The operators performed well, and maintained a strong emphasis on reactivity management with good command and control during the reactor startup.

O2 Operational Status of Facilities and Equipment

O2.1 Secondary Equipment Challenges During the Forced Outage

a. Inspection Scope (71707, 62707)

The inspectors reviewed the licensee's response to several equipment problems that occurred after the reactor trip on August 12, 1999.

b. Observations and Findings

In addition to responding to the expected equipment conditions following the reactor trip on August 12, 1999. The operators noted several other unexpected equipment responses during the transient. Specifically, an inadvertent carbon dioxide (CO_2) discharge onto the 31 main boiler feedwater pump (MBFP), a failure of a secondary steam valve, and a third occurrence of an auxiliary boiler feedwater pump (ABFP) that was steaming through its shaft seal after the pump auto started in response to a reactor trip signal.

The ABFPs receive an automatic start signal upon a reactor trip to provide a reliable source of cooling water to the steam generators. During the August 12 transient, the ABFPs started on demand; however, a nuclear plant operator noted excessive steam coming from the packing gland of the 31 ABFP. Maintenance personnel responded by loosening the packing gland on the pump to alleviate the steaming condition and the pump remained in service for the duration of the event. NRC inspection reports 50-286/98-09 and 99-01 documented previous occurrences of this problem, and concluded that the licensee's equipment failure evaluations were poor. The issue was in the licensee's corrective action program and plans to change the design and material of the pump packing were developed. The licensee had not implemented this design change before August 12; however, the packing was replaced with the new design and material prior to starting up the reactor on August 13.

Another unexpected equipment response included the failure of motor-operated valve (MOV) MS-6-4 to close, which supplies steam to the secondary plant reheaters. The valve is not safety-related and the only impact of the failure was to cause a minor distraction to the operators during the transient. Also, a CO_2 discharge onto the 31 MBFP was reviewed and determined to be caused by loose fittings and an inadvertent bumping or jarring of the CO_2 pipes surrounding the pump. The licensee performed a walkdown to assure proper pump performance, the CO_2 system was temporarily defeated, and a continuous firewatch was assigned.

c. Conclusions

The licensee was unnecessarily challenged by safety-related and nonsafety-related secondary equipment during the plant transient on August 12. A third incident of degraded auxiliary boiler feed pump packing was observed during the reactor trip transient. Also, a carbon dioxide discharge onto the main boiler feedwater pumps and a failure of a secondary steam supply valve provided minor distractions to the operations crew coping with the transient.

O3 Operations Procedures and Documentation

O3.1 Review of Off-Normal Operating Procedure (ONOP), EL-3, "Loss of an Instrument Bus"

a, Inspection Scope (71707)

The inspector reviewed off-normal operating procedure (ONOP) EL-3, "Loss of an Instrument Bus," to assess the guidance regarding secondary pressure control had been given during the transient on August 12.

b. Observations and Findings

The inspector reviewed off-normal operating procedure (ONOP) EL-3, "Loss of an Instrument Bus," and noted that the procedure did not contain sufficient information regarding the challenges to secondary pressure control during this particular transient. Specifically, the procedure did not state that two of four steam generator atmospheric relief valves would be unavailable due to a loss of their control power. Also, the procedure did not identify the unavailability of the condenser steam dumps that occurred due to the loss of power to one of the reactor coolant system temperature averaging channels.

This partial loss of secondary pressure control challenged the operators and the secondary pressure relief valves. Although the steam generator safety relief valves (SRVs) were designed to initially relieve secondary plant pressure after a reactor trip if the atmospheric relief valves (ARVs) are unavailable, in this particular transient one SRV lifted a total of three times within an approximate 1-1/2 hour period partly because the operators did not take positive action to reduce the actuation settings on the two available ARVs.

During the post-transient review, the licensee identified that it may be necessary to make some enhancements to the off-normal operating procedure (ONOP), but did not consider this a necessary item to be completed prior to commencing a plant re-start. However, senior NYPA management did require that the lessons learned from this event be disseminated to all operating crews. The inspector observed the shift briefing prior to startup and noted that operations management had incorporated specific secondary pressure control information into the shift orders. The inspector reviewed this information and questioned the licensee about their decision to put what appeared to be procedural guidance for an off-normal occurrence into a shift order rather than writing a temporary procedure change (TPC) for the ONOP. The licensee revised the shift order to make it less specific and to incorporate a reference to current plant procedures, but did not issue a TPC.

The inspector reviewed operations directive (OD)-1, "Operations Department Standing Orders, Shift Orders, and Policies." Section 4.2.4 of this procedure stated that, "shift orders shall not be used as a substitute for approved station procedures, temporary operating procedures, or temporary procedure changes." However, in response to the senior management request to disseminate the lessons learned from the trip to the operating crews, the operations manager issued and briefed the operating crew with a shift order that included specific operator actions associated with secondary pressure control. The order noted that if a loss of the 34 instrument bus occurred, operators should make an effort to reduce the reactor coolant temperature to normal no load temperature of 547° F using the steam generator (SG) atmospherics on the 31 and 34 SGs. When the inspector questioned operations management about the nature of this procedure, it was revised to a single statement in an effort to reduce reactor coolant temperature using applicable plant procedures without providing the specific guidance as to how this should be accomplished. The inspector noted that the original shift order that contained the specific operator action was not in accordance with the licensee's operations directive (OD-1), "Operations Department Standing Orders, Shift Orders, and Policies," section 4.2.4. This was not consistent with existing requirements that procedures be implemented covering activities referenced in Appendix A of Regulatory Guide 1.33, "Quality Assurance Program Requirements," November 1972. However, due to the absence of adverse consequences in this case, this is considered to be a minor violation and is not subject to enforcement consistent with Appendix C of the NRC Enforcement Policy. The licensee subsequently revised ONOP EL-3 and included specific instructions for loss of the 34 instrument bus that requires operators to determine if the steam dumps are available, and if not, to put the available ARVs in automatic and manually adjust their setpoints to 71% (approximately 1000 psig).

c. <u>Conclusions</u>

The off-normal operating procedure for the loss of the 34 instrument bus did not provide sufficient guidance to the reactor operators in how to manage secondary pressure control when this instrument bus is lost. As a result, some challenges to the operators and to plant equipment were noted that complicated a transient on August 12, 1999. However, in order to disseminate the lessons learned, the operations manger issued a shift order that contained specific actions for operators, even though the licensee's operations administrative procedure does not allow this practice.

O8 Miscellaneous Operations Issues

O8.1 Outage Risk Assessment Review

a. Inspection Scope (71707)

The inspector reviewed a licensee's risk assessment for the RO-10 refueling outage schedule, and discussed the recommendations made by the risk assessment team with plant staff members.

b. Observations and Findings

Members of the Independent Safety Engineering Group (ISEG), operations, and training departments performed a shutdown risk assessment of the RO-10 refueling outage schedule. The assessment reviewed the status of key safety functions, such as core cooling, reactivity, and power availability, for the duration of the planned outage. The team identified more than thirty recommendations for schedule changes or other enhancements to improve defense-in-depth for the key safety functions. The recommendations were placed in the plant action and commitment tracking system and most were completed at the time of the inspection.

The inspector determined that the risk assessment was detailed and thorough. The recommendations made by the risk assessment team resulted in a number of substantial improvements to the schedule, increasing equipment redundancy for key safety functions. The inspector reviewed the recommendations and noted that they were tracked and incorporated in a satisfactory manner. No issues were identified with the revised outage schedule.

c. Conclusions

A detailed and thorough licensee-performed risk assessment of the RO-10 refueling outage schedule resulted in a number of improvements to the schedule, thereby increasing equipment redundancy for key safety functions.

O8.2 (Closed) LER 50-286/1999-010: Reactor Trip Due to Low Level in Steam Generator Caused by Loss of 34 Instrument Bus. The details associated with this LER are discussed in report detail O1.1. The inspectors determined through an in-office review that the LER contained sufficient detail to explain the root cause of the reactor trip and to identify the necessary corrective actions in accordance with 10 CFR 50.73. No enforcement actions were warranted for issues related to this LER.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Maintenance General Comments

a. Inspection Scope (62707)

The inspectors reviewed selected maintenance work activities and supporting work documentation. Activities were selected based on the systems, structures, or components contained within the scope of the maintenance rule.

b. Observations and Findings

The inspectors observed all or portions of the following work activities:

WR 99-03284, "31 EDG Jacket Water Cooler Temperature Switch Replacement"
WR 98-00175-00, "31 EDG Quarterly Preventive Maintenance"
WR 99-03063-00, "Auxiliary Boiler Feedwater Pump Preventive Maintenance"

c. Conclusions

Maintenance activities observed were conducted satisfactorily and in accordance with applicable maintenance and administrative procedures. The licensee appropriately monitored performance of equipment within the scope of the maintenance rule.

M1.2 Surveillance General Comments (61726)

a. Inspection Scope (61726)

The inspectors reviewed selected surveillance test activities and their supporting documentation. The activities were selected based on the systems, structures, or components contained within the scope of the maintenance rule.

b. Observations and Findings

The inspectors observed all or portions of the following surveillances:

3PT-M79C, "33 Emergency Diesel Generator Functional"
3PT-Q92, "Service Water Pump Functional"
3PT-Q116B, "Safety Injection Pump Functional"
3PT-M07A, "RPI Analog System Functional"
3PT-M90, "Appendix R Diesel Generator Functional Test"

c. Conclusions

Surveillance tests were conducted appropriately and in accordance with procedural and administrative requirements. Good coordination and communication with the control room were maintained during performance of the observed surveillances. Test instrumentation was within calibration and the test acceptance criteria were achieved.

M1.3 Appendix R Diesel Generator Functional Test

a. Inspection Scope (61726)

The inspector reviewed surveillance test 3PT-M90, "Appendix R Diesel Generator Functional Test," and observed the performance of the test. The inspector also verified that the acceptance criteria of the test were consistent with the licensee's design basis documents for the (10 CFR 50) Appendix R Diesel Generator.

b. Observations and Findings

The inspector observed good self-checking by the nuclear plant operators performing the surveillance. In addition, the inspector observed a questioning attitude and extensive use of procedures. Overall, the implementation of the surveillance was appropriate and in accordance with licensee procedures.

However, the inspector noted that the test procedure contained no verification for the speed setting on the engine mechanical governor, which affects the speed of the engine. This appeared inconsistent with the method of configuration control used for the 480 volt emergency diesel generators (EDGs). The governor speed setting for the EDGs is verified by both the system alignment check-off list and the nuclear plant operators' watch logs. However, the test and operating procedures, and the operator logs for the Appendix R diesel did not contain a verification for the speed setting. The correct setting was established in January 1996 by a vendor representative when the governor was replaced, but the correct setting had not been translated into the engine's operating or test procedures. The inspector questioned NYPA engineering about this potential shortcoming in configuration controls for the Appendix R diesel. Engineering's position was that because the Appendix R diesel does not get an automatic start in the same manner as the EDGs, configuration control verification of the speed setting was not necessary. Although an operator would be present to start the diesel when needed for service, if the diesel tripped from an inaccurate speed setting, it would not be readily apparent to the operator. The inspector considered that this could present a challenge to the operators and to the plant itself because the Appendix R diesel generator is relied upon to supply power to safety-related equipment under the equipment failure scenarios defined in 10 CFR 50, Appendix R. The inspector verified the speed setting on the governor was correct and the system engineer subsequently recommended to operations that the governor's speed setting be added to the prerequisite check-off list (COL-EL-6) referenced in the engine operating and test procedures. Operations planned to the revise the COL as necessary.

The inspector also noted several problem identification (PID) tags hanging on the diesel control panel. These PIDs had been written by operations to note perceived deficiencies in the implementation of the surveillance test. For example, one PID noted that the generator AC voltage gauge was reading approximately 40 volts higher than the setting called for in the procedure, and that having to set the voltage above the procedural guidance constituted an "operator workaround." The gauge in question had large gradations that made distinguishing ±40 volts difficult. Both system engineering and planning had reviewed this PID and determined that the problem noted on the PID could not be addressed due to the nature of the gauge. However, this information had not been effectively communicated to the operations department, nor had the PID been canceled. The system engineer stated that the voltage gauge would be recalibrated prior to the next monthly engine test, that the PID would be appropriately dispositioned. The inspector noted that while none of the PIDS associated with the Appendix R diesel impacted the operability of the engine, poor communication between engineering, planning, and operations resulted in perceived unresolved problems associated with it.

c. <u>Conclusions</u>

The performance of the Appendix R diesel generator monthly surveillance test was good. Procedures and self checking techniques by the test performers were used effectively and in accordance with licensee procedures. However, neither the test or operating procedure verified the correct speed setting on the engine mechanical governor. The configuration control verification for the diesel was not thorough and may not have prevented inadvertent tripping of the Appendix R diesel when called upon for service if the governor's speed setting had been inadvertently altered. The licensee appropriately planned to revise the system prerequisite check-off list to verify the speed setting. Some poor communication between system engineering, planning, and operations was noted as problem identification tags remained on the engine control panel even though the problems had been reviewed and deemed acceptable by both planning and engineering.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 (Closed) Inspection Follow-up Item (IFI) 50-286/98008-02: Effectiveness of Past Corrective Actions for Water Intrusion in the 32 Emergency Diesel Generator Fuel Oil Storage Tank (NCV 50-286/99007-01).

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

During a monthly sample of the 32 emergency diesel generator (EDG) fuel oil storage tank on August 25, 1999, the licensee found approximately 5-1/2 inches of water at the bottom of the tank. The inspectors reviewed the details of this event and the licensee's response to restore the diesel to operability. The inspectors also evaluated the safety implications associated with the fuel system degradation and reviewed the licensee's corrective actions for past instances of water intrusion in the tank. This IFI was opened to evaluate the effectiveness of the licensee's corrective actions to prevent a recurrence of the water intrusion.

b. Observations and Findings

Fuel Transfer System Design and Operation

The EDG fuel oil supply system at Indian Point 3 (IP3) was designed as safety-related, seismic class 1, in accordance with USA piping specification B31.1. The fuel oil tanks were originally fabricated in accordance with the American Society of Mechanical Engineers (ASME) Code Section VIII, and the licensee currently classifies the tanks as QA Category I equipment. The system has three 7700 gallon storage tanks, each with a transfer pump that delivers fuel to three 175 gallon day tanks. Each day tank gravity feeds fuel to one diesel engine through two sets of 10 micron duplex filters. All three storage tanks are buried underground adjacent to the EDG enclosures, and all have a concrete bunker for valves and piping above the top of each tank. All piping enters the top of each tank through the bottom of its bunker. All storage tanks are vented to the atmosphere, and installed with a design slope of 3 inches across their length so that any water accumulation (primarily from condensation) would settle at one end. Each transfer pump is submerged at the higher end of the tank and takes a suction approximately 5 inches off the bottom. For maximum reliability, the system piping was configured so that each storage tank could replenish all three day tanks through one of two fuel supply headers. One header supplies fuel from the 31 and 32 storage tanks, and the other from the 33 storage tank. When the level in any day tank reaches 85%, level control valves in both supply headers open to emit fuel. When the level decreases to 65%, the transfer pump in the corresponding storage tank starts and delivers fuel to all three day tanks through the supply header. If all three diesels are operating, all six level control valves will be open by the time any day tank reaches 65%. When the first transfer pump starts, all three day tanks will be replenished simultaneously.

Section 8.2 of the IP3 final safety analysis report (FSAR) referenced the licensee's accident loading study for the three emergency diesel generators (EDGs), and indicated that the electrical loads automatically sequenced onto the 2A safeguards bus (supplied by the 32 EDG) would be 1836-1890 megawatts (MW), or 200-500 MW higher than the other two safeguards buses. Therefore, the 32 EDG would draw down its day tank quicker, and its storage tank would supply all three day tanks until it reaches its low level. Upon reaching a 65% level in the 32 day tank, the 32 fuel transfer pump would start, and any water pumped out of the storage tank would be delivered to all three day tanks. During a design basis event, with all three EDGs operating, this condition would represent a potential common mode failure of all three EDGs if a sufficient volume of water accumulated in any of the fuel storage tanks and was pumped into the three day tanks.

Licensee Response to Recent Instances of Water Intrusion

In March 1998, the licensee observed an accumulation of water in the 32 fuel oil storage tank and initiated DER 98-0387 to address the condition. This was reported as the second occurrence of a measurable quantity of water at the bottom of the 32 tank in two consecutive months. The DER indicated that storage tank integrity was not met; however, the EDG was declared operable after water in the tank was pumped out and tank integrity was declared satisfactory. The DER did not identify a root cause for the degraded condition and indicated that the cause of the water intrusion was not known. The DER also did not report the degradation as a nonconformance. The apparent cause for the condition was listed as "Man-machine interface - equipment condition." The licensee subsequently developed Action Plan IMD-APL-98-001 that included two required actions to address the water intrusion: 1) clean and seal around piping to the tank, and 2) ultrasonically examine the base metal in the 2-, 3-, and 4-inch piping to the tank, and its manway (all piping examined was above the minimum wall thickness by at least 0.008 inch). The plan also included two contingency actions: 1) to perform a tank integrity test if water intrusion continued (later canceled after the in-leakage was considered to be above the tank liquid level), and 2) to evaluate options for repairing the tank. The licensee increased the periodic sampling for water from monthly to weekly; however, all actions were closed out and the weekly sample was returned to monthly in September 1998, based on no further instances of water intrusion.

In October 1998, the licensee observed approximately 2 inches of water on the bottom of the 32 EDG fuel storage tank during the monthly sample, and initiated DER 98-2019 to address the incident. The DER indicated that tank integrity was not met, but that the possible cause was "unknown/undetermined" and was being investigated. The DER listed the apparent cause as "other." The DER did not list the condition as a non-conformance, and did not indicate that the leak represented a degraded condition in safety-related, seismic category 1 piping. However, the licensee developed a second action plan (IDSE-APL-98-020) to further address the condition. Some required actions within the plan included 1) to re-inspect the sealant previously applied around the pipe penetrations, 2) to apply new sealant around the steel plates above the top of the valve bunker over the storage tanks to prevent the intrusion of rain water into the valve bunkers, and 3) to design a drainage collection system from the valve bunker "drywell" holes to keep the bunkers dry. Action 2) was listed as complete in the action plan; however, it appeared that the sealant was applied only once in November 1998, and was broken when the next monthly sample was taken. Maintenance personnel stated that there had been no regularly scheduled activity or formal plan to assure the plates were sealed after each sample, and expected the chemistry technicians to call them after the monthly sample was taken so the plates could be sealed again. This arrangement was made by verbal agreement only, and was not followed through after November 1998. At the end of the current inspection, no actions had been taken by engineering on action 3) since the work request to evaluate a design concept was only recently approved.

On August 25, 1999, the licensee measured approximately 5-1/2 inches at the bottom of the 32 storage tank, and issued DER 99-1714. This was the fourth occurrence of a significant amount of water in the tank in approximately 17 months. The EDG system engineer initially estimated the volume of water to be 50 gallons, and that that amount would have been approximately one inch below the transfer pump impeller. He also considered that the water would have been sucked into the transfer pump if it had started. Consequently, the shift manager declared the 32 EDG inoperable based on the system engineer's recommendation. The licensee then obtained bulk samples of the fuel oil in all three storage tanks and all three day tanks, and concluded that all fuel in the system was still within the manufacturer's specification for water content (<0.05%). The licensee removed all water from the bottom of the storage tank, declared the 32 EDG operable, and then obtained an additional sample of the water and oil for further laboratory analysis. That sample contained an approximate 1/4 inch layer of biological growth in the water just under the oil layer, which prompted the licensee to apply a biocide to the sample and to the fuel in all storage tanks. Identification of the biological species (probably an anaerobic fungus) was in progress at the end of this inspection period; however, it was evident that the biological material would not have passed through the duplex filters downstream from the day tanks and could have blocked fuel flow to the diesels. The licensee also initiated daily samples of the 32 storage tank for water, but none was observed during the remainder of this inspection period. The inspector witnessed one sampling on August 30, and verified that no water was present on that date.

At the end of the current inspection period, the licensee had not precisely quantified the volume of water in the 32 tank on August 25. At the slope of the tank actually measured in October 1998, the system engineer estimated that 5-1/2 inches at the deep end would correspond to approximately 70 gallons and would be enough to reach the impeller of the transfer pump. However, chemistry personnel estimated that only 30 gallons were actually removed from the tank. The inspector observed the pumpdown of the tank and estimated that more than 30 gallons were actually removed since some water was lost onto the ground during pump priming. It appeared that the 32 EDG would not have been inoperable with 30 gallons in the tank, but that it would have been inoperable if 50 gallons were in the tank.

The licensee's investigations to date have preliminarily concluded that the water intrusion was related only to rainfall that entered the tank through degraded system piping between the overhead bunker and the top of the tank. After a significant rainfall, the valve bunkers had been seen with standing water that would take a long time to drain, and that could have corroded through piping to provide a path for water in-leakage. DERs 98-0387 and 98-2019 did not identify a root cause of the water in-leakage. The most recent DER (99-1714) referred to the root cause as a "degraded subcomponent;" however, that DER was closed (based on items still open under the action plan) after one day when the water was removed from the tank and the diesel declared operable. Both action plans did not identify the significance of degradation in a safety-related seismic class 1 system, or the safety significance of the existing level of degradation. Although the licensee planned to drain the 32 storage tank during the upcoming refueling outage to perform inspections and repairs, the licensee's actions to date were not comprehensive or timely to prevent a significant recurrence of the problem.

The NRC considers the degradation of the fuel transfer system to be a significant condition adverse to quality that could threaten the ability of the emergency diesels to operate. The condition of this system grew progressively worse over a 17 month period, and the licensee's actions did not prevent a recurrence of water intrusion. The risk of a common mode failure of all three EDGs became significant given the degradation in the 32 storage tank or its associated piping that allowed significant water intrusion to occur. This IFI is closed **(IFI 50-286/98008-02)**, and is considered to be a severity level IV violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action;" however, it will be regarded as a non-cited violation in accordance with Appendix C of the NRC Enforcement Policy (**NCV 50-286/99007-01**).

c. Conclusions

The licensee did not take adequate corrective actions to identify the root cause or to prevent a significant accumulation of water in the bottom of the 32 emergency diesel generator (EDG) fuel oil storage tank. Three prior instances of water accumulation were identified by the licensee and were entered into their corrective action system. However, the corrective actions in the licensee's October 1998 action plan were not complete and did not prevent the recurrence of a significant condition adverse to quality. That condition could have resulted in a common mode failure for all three EDGs due to a fuel transfer system design that could have transferred the water to each diesel generator day tank. This is considered to be a severity level IV violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action;" however, it will be regarded as a non-cited violation in accordance with Appendix C of the NRC Enforcement Policy (**NCV 50-286/99007-01**).

M2.2 31 Auxiliary Boiler Feedwater Pump Post-Maintenance Test Failure

a. Inspection Scope (62751)

On August 4, 1999, the licensee declared the 31 auxiliary boiler feedwater pump (ABFP) inoperable after determining that motor vibration data previously taken during routine post-maintenance testing was unacceptable. The inspector reviewed the details of the test data, and the licensee's response to the limiting condition for operation (LCO) action statements specified by the technical specifications.

b. Observations and Findings

The 31 ABFP was removed from service on August 4, 1999, to perform routine preventive maintenance (PM) that included an annual lubrication of the flexible mechanical coupling between the pump and motor. This PM required entry into LCO 3.4.A.2.1, which allowed the pump to remain out of service for 72 hours. The licensee considered the PM to be minor maintenance, and consequently, no post-maintenance test applicable to the lubrication was specified before the pump was returned to service approximately 16-1/2 hours later. The following day, the licensee conducted the quarterly surveillance test (PT-Q120A) required by the technical specifications. PT-Q120A contained test acceptance criteria that reflected the pump operating specifications (flow and differential pressure) and also contained the minimum number of inspection points for pump vibrations required by the ASME Section XI inservice test (IST) program. These points included the horizontal and vertical components of the pump outboard bearing, and the axial thrust for the pump shaft. The ABFP met all of the required IST acceptance criteria specified by the test, and it was returned to service after approximately 1 hour of testing. Additional vibration data not required by the IST program was taken on the pump and motor and was recorded in the PT; however, these data did not have specific acceptance criteria listed, and were used primarily for performance trending.

Shortly after completing the surveillance test, the ABFP system engineer noted that vibration data taken on the motor exceeded .5 in/sec. This value was above the licensee's administrative limit of .45 in/sec, which was based on a generic industry recommendation. The licensee declared the pump inoperable, again entered LCO 3.4.A.2.1, and conducted troubleshooting to determine the cause. It was later determined that the high motor vibrations resulted from excessive grease inside the mechanical coupling between the pump and motor that caused the coupling to lock up hydraulically. This caused a small misalignment between the motor and pump shafts to result in high motor vibration. The licensee completely disassembled and cleaned the coupling, then re-greased and reassembled it using the proper amount of grease. The pump and motor were then realigned and re-tested using PT-Q120A, and all vibration data was satisfactory. The licensee exited LCO 3.4.A.2.1 and the pump was returned to service on August 6, after approximately 22 hours of rework and testing. Subsequently, the licensee made a substantial revision to the PM procedure to require a complete disassembly, cleaning, re-greasing, and reassembly of the coupling, and added details to avoid excess grease. The larger maintenance scope will require an appropriate post-maintenance test in the future as required by the licensee's maintenance program.

The inspector also questioned the pump vibration data in surveillance procedure PT-Q120A that did not have operability acceptance criteria. Performance monitoring personnel indicated that the generic limits on motor vibration for trending should not necessarily be used for pump operability because some high vibration conditions may be acceptable for a limited time. As an alternative, the licensee agreed that the test procedure should allow the system engineer to evaluate high vibration conditions before the pump is returned to service, and to provide input to assist operations in determining the operability of the pump. Performance monitoring personnel indicated that this could be an appropriate process for evaluating trend data that could potentially impact operability on other pumps and motors.

During the rework period, the inspector questioned the licensee's process for determining the amount of time remaining under the LCO action statement after it was entered a second time on August 5 for a condition that was caused during the first entry on August 4. The shift manager considered that the LCO entry on August 5 was a separate entry from the August 4 entry, since the first entry was appropriately exited after all acceptance criteria defined in the PT were properly satisfied. The shift manager also considered that an additional 72 hours were available based upon the time of discovery. However, the unacceptable vibration data resulted from maintenance conducted during the first LCO entry, and if an appropriate post-maintenance test had been conducted, the licensee would not have exited the LCO. The licensee made a conservative decision to repair, retest, and return the 31 ABFP to service within 55 hours of a continuous 72 hour period beginning with the first LCO entry on August 4. However, the inspector noted that the licensee did not have a formal policy or process to address multiple LCO entries that occur in a short period which may have a related cause. The licensee agreed that this situation should be reviewed, and that guidance may be developed.

c. Conclusions

The licensee's preventive maintenance did not include a sufficient post-maintenance test to provide an adequate basis for operability of the 31 auxiliary boiler feedwater pump.

The pump was later declared inoperable due to motor vibration data that was above administrative limits. The licensee's maintenance and test procedures were revised to require appropriate evaluation and testing. This is considered to be a minor violation and is not subject to enforcement consistent with Appendix C of the NRC Enforcement Policy.

III. ENGINEERING

E1 Conduct of Engineering

E1.1 Emergency Diesel Generator Service Water Flow Balance (NCV 50-286/99-007-02).

a. Inspection Scope (37551, 61726)

In response to anomalous service water flow readings documented in NRC inspection report 50-286/99-05, the inspector reviewed the results from the service water flow balance test conducted during the last refueling outage. The review included an evaluation of the licensee's resolution of identified deficiencies.

b. Observations and Findings

During the last service water flow balance test in August 1997, the licensee identified that two acceptance criteria were not met. The first was associated with service water flow to the 32, 34, and 35 containment fan cooler units (FCUs), and the second was associated with service water flow to the 31 emergency diesel generator (EDG) that would exist during the recirculation phase of a postulated design basis loss-of-coolant accident (LOCA).

Regarding service water flows to the FCUs, Raytheon calculation 83990-164-SW-101 and a letter dated September 9, 1998, documented the acceptability of the as-found test results. The inspector determined that the calculational methodology was sound and the results provided adequate margins to ensure that the required minimum service water flows to the FCUs were met. Although the documentation did not explicitly provide the basis for certain assumptions in the calculation (such as the system flow coefficients that remained unchanged from the previous test conducted in 1989), the bases for the assumptions were known by NYPA engineers when questioned by the inspector.

Regarding the service water flow to the EDGs, Raytheon calculation 83990-164-SW-101 also documented the acceptability of the as-found test results. Similar to the FCU calculation, the calculational methodology was sound and the results provided adequate margins to ensure minimum service water flows to the 31 EDG were met. However, the inspector noted that the calculated results showed that the service water flows to the 32 and 33 EDGs were reduced significantly when the plant transitioned from a safety injection configuration to a recirculation configuration. The service water flows had dropped from about 450 gpm to about 375 gpm (the test acceptance criterion was approximately 330 gpm). In the post-LOCA recirculation configuration, some safety-related components (e.g., the 31 EDG) would be placed on the non-essential header. Service water flow through the 32 and 33 EDGs would be reduced due to the interaction of the essential and non-essential service water headers on the common return side from the EDG heat exchangers.

The inspector also noted that the 1997 test configuration used one service water pump on the non-essential header and two service water pumps on the essential header. However, emergency operating procedure EOP ES-1.3, "Transfer to Cold Leg Recirculation," directed the starting of a second non-essential service water pump. In this configuration, a more limiting flow condition through the 32 and 33 EDGs would occur. This more limiting condition was neither considered nor analyzed by the licensee during the review of the service water test in 1997.

In response to the inspector's observations, a computer-generated analysis was performed for the post-LOCA recirculation configuration with two service water pumps operating in the non-essential header. The results showed that the service water flows to the 32 and 33 EDGs were 308 and 309 gpm, respectively, which was below the original calculated acceptance criterion of 330 gpm. However, the licensee noted that conservative margins were incorporated into the calculated acceptance criterion. As a result, an operability determination was performed which documented an actual minimum flow requirement of 302 gpm. The inspector questioned how the uncertainty within the computer model would be analyzed to assure appropriate margins were met for the service water flows. The licensee responded with information that maintained that the maximum diesel loading under post-LOCA recirculation conditions was 1602 KW instead of the originally assumed 1950 KW. When this loading value was entered into the computer model, the resulting required flow for the 32 and 33 EDG coolers was 213 gpm. The licensee initiated DER 99-1281 and indicated that 213 gpm will be incorporated into the licensee's acceptance criteria for the service water flows, as well as the design basis calculations.

The inspector noted that the original service water test in 1997 had acceptance criteria based on erroneous design basis information. This was not identified until 1999 after the question was raised by the NRC inspector. The licensee did not correctly translate flow requirements into the design basis calculation and the engineering surveillance test for the service water system.

c. <u>Conclusions</u>

Engineering evaluation of flow requirements described in the licensee's emergency operating procedures was not translated into the acceptance criteria of a service water flow performance test. Specifically, the back pressure resulting from the addition of a service water pump onto the non-essential header was not accounted for in the acceptance criteria nor the design basis calculation for the system. This is a violation of 10 CFR 50 Appendix B, Criterion III, "Design Control." This severity level IV violation is being treated as a non-cited violation in accordance with Appendix C of the NRC Enforcement Policy. **(NCV 50-286/99007-02)**.

E8 Miscellaneous Engineering Issues

E8.2 (Closed) Licensee Event Report (LER) 1999-008: "Plant Outside Design Basis Due to an Error in an Assumption in the Main Steam Line Break Analysis"

In March 1999, the licensee reviewed a 10 CFR Part 21 notice issued by Rochester Gas and Electric (licensee for the R. E. Ginna Nuclear Plant), after that licensee was notified by its nuclear steam supply system vendor (Westinghouse) of modeling errors in the accident analysis for a main steam line break (MSLB). One modeling error involved an underestimate of the volume of water in the piping and feedwater heaters between one SG and a main boiler feedwater pump (MBFP). This water could be delivered to containment through a faulted steam generator following a MSLB if a feedwater regulating valve (FRV) failed to close, and feedwater delivery continued until the associated MBFP discharge valve closed. Also during March 1999, NYPA reactor engineering personnel contacted Westinghouse to review the Part 21 report and the potential for errors in the MSLB analysis for IP3. However, Westinghouse indicated that IP3 remained within its current design basis, and that the accident analysis for IP3 would not have to be revised to correct the same errors observed in the Ginna plant. In April 1999, NYPA initiated DER 99-0853 to track the Part 21 notice, and to review the existing calculation for feedwater volume assumed in the MSLB analysis for IP3.

In June 1999, NYPA completed calculation IP-3-CALC-MFW-03025, "Main Feed Water Discharge Pipe Volume Calculation," which determined that the feedwater volume used in the MSLB analysis was underestimated by 3783 ft^3 (the existing calculation assumed a generic 800 ft^3 for four-loop plants similar to IP3). The licensee subsequently initiated DER 99-1485, and transmitted this result to Westinghouse. Westinghouse indicated that the additional volume could be accounted for through conservativisms in the existing computer code for the analysis, e.g. the excessive time assumed for the main feedwater discharge valves to close. Following this result, the IP3 plant remained operating because an operability determination demonstrated that the calculated peak containment pressure would still remain within the design maximum (47 psig) if additional available shutdown margin were assumed in the analysis that would reduce the total energy released into containment. Westinghouse subsequently initiated a revision to the MSLB analysis for IP3 based upon the information provided by NYPA on the corrected feedwater volume.

On July 22, 1999, Westinghouse notified the licensee that a preliminary calculation for a MSLB with one failed FRV showed that containment pressure could not be maintained below the existing design basis maximum unless changes were made to current licensing basis assumptions for shutdown margin and/or boron concentration in the high head safety injection system. The existing licensing basis design inputs for IP3 credited a 1.3 percent shutdown margin and zero parts per million (ppm) boron. Based upon this result, Westinghouse revised the calculation using a 2.9 percent shutdown margin while maintaining zero ppm boron, and demonstrated that the maximum containment pressure could remain within its design limit. Later on July 22, NYPA issued a 10 CFR 50.72 notification to the NRC that IP3 was outside its current design basis, but that the containment remained operable with the higher shutdown margin available within the current design. The 50.72 report was subsequently followed up with LER 1999-008 on August 23, 1999, which indicated that the licensee would submit a license amendment request to revise the current technical specification value for shutdown margin from 1.3 to 2.9 percent. The licensee also anticipated that the 10 CFR 50.59 core reload analysis for the next operating cycle would need to reflect the increase in shutdown margin credited in the revised MSLB analysis.

The inspector reviewed LER 1999-008, and performed in-plant evaluations of the available shutdown margin reported in the LER. Immediately following the 50.72 report, the inspector confirmed that the available margin exceeded 2.9 percent, and noted that the actual margin was more than 4.5 percent. This margin was also increasing slightly as the reactor core approached end of life. The LER indicated that the cause of the modeling errors in the MSLB accident could not be determined since the feedwater volume had been underestimated using generic information provided by Westinghouse in 1989. The inspector concluded that LER 1999-008 contained the necessary information required by 10 CFR 50.73 to describe the event and to indicate the necessary corrective actions. NYPA reactor engineering demonstrated a proactive response to a 10 CFR Part 21 Notification by Rochester Gas & Electric by evaluating its potential impact on IP3, and by identifying errors and initiating corrections through Westinghouse to the existing design basis analysis of record.

E8.2 (Closed) LER 1999-009; "Loss of Containment Integrity Due to Personnel Error." NRC inspection report 50-286/99-05 documented the review of this event. No new issues were revealed by the LER. The inspector concluded that LER 1999-009 contained the necessary information required by 10 CFR 50.73 to describe the event and to indicate the necessary corrective actions.

X1 Exit Meeting Summary

On October 5, 1999, the resident inspectors presented the inspection results to members of the licensee's management. The licensee acknowledged the findings presented.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Barrett, Site Executive Officer
F. Dacimo, Plant Manager
J. Comiotes, General Manager-Operations
D. Mayer, Acting General Manager-Support Services
J. Russell, General Manager-Maintenance
J. DeRoy, Director, IP3 Engineering
K. Kingsley, Acting Manager, Licensing

INSPECTION PROCEDURES USED

IP 37551:	On-site Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Event Reports
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

NCV 50-286/99007-01	Ineffective Corrective Actions for Water Intrusion in the 32 Emergency Diesel Generator Fuel Oil Storage Tank
NCV 50-286/99007-02	Failure to incorporate service water flow requirements into a design basis calculation and system test procedure

Closed

IFI 50-286/98008-02:	Effectiveness of Past Corrective Actions for Water Intrusion in the 32 Emergency Diesel Generator Fuel Oil Storage Tank
LER 1999-008:	Plant Outside Design Basis Due to an Error in an Assumption in the Main Steam Line Break Analysis
LER 1999-009:	Loss of Containment Integrity Due to Personnel Error.
LER 1999-010:	Reactor Trip Due to Low Low Level in Steam Generator Caused by Loss of 34 Instrument Bus

LIST OF ACRONYMS USED

ABFP	auxiliary boiler feedwater pump
ARV	atmospheric relief valve
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CO_2	carbon dioxide discharge
COL	Check-off List
DER	deviation event report
EDG	emergency diesel generator
EOP	emergency operating procedure
FCU	fan cooler unit
FRV	feedwater regulating valve
FSAR	Final Safety Analysis Report
gpm	gallons per minute
IFI	inspector follow-up item
ISEG	Independent Safety Engineering Group
IST	inservice test
LCO	limiting condition for operations
LER	licensee event report
LOCA	loss-of-coolant accident
MBFP	main boiler feedwater pump
MOV	motor operated valve
MSLB	main steam line break
MW	megawatts
NCV	non-cited violation
NSSS	nuclear steam supply system
OD	operations directive
ONOP	off-normal operating procedure
PDR	Public Document Room
PID	problem Identification
PM	preventive maintenance
PORV	pressurizer power-operated relief valve
ppm	parts per million
PTRG	post-transient review group
QA	quality assurance
RCS	reactor coolant system
RPS	reactor protection system
SG	steam generator
SRV	safety relief valve
STA	shift technical advisor
TPC	temporary procedure change
TS	technical specifications