February 11, 2000

Mr. T. C. Feigenbaum
Executive Vice President and Chief Nuclear Officer
Seabrook Station
North Atlantic Energy Service Corporation
c/o Mr. James M. Peschel
P. O. Box 300
Seabrook, NH 03874

SUBJECT: NRC INSPECTION REPORT NO. 05000443/99009

Dear Mr. Feigenbaum:

This refers to the inspection completed on January 16, 2000 at the Seabrook Nuclear Power Station. The enclosed report presents the results of this inspection.

Your staff placed an appropriate emphasis on safe plant operations during the period. A planned down power, and subsequent reactor start-up were performed well. Despite the generally good performance, several operational deficiencies allowed an increased volume of seawater to enter the steam generators during a secondary chemistry event. Specifically, the operating procedure and existing management expectations enabled the operators to maintain the condensate lined up in preparation for placing an idle pump in-service for an extended period of time. Additionally, the operators were slow to respond to three condensate system alarms during the event. Your corrective actions for this event, and continuing investigation to identify the root causes for this event appear to be appropriate.

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

Sincerely,

/RA/

James C. Linville, Chief
Projects Branch 6
Division of Reactor Projects

Docket No. 05000443
License No: NPF-86

Enclosure: NRC Inspection Report No. 05000443/99009

cc w/encl:

B. D. Kenyon, President - Nuclear Group
J. S. Streeter, Recovery Officer - Nuclear Oversight
W. A. DiProfio, Station Director - Seabrook Station
R. E. Hickok, Nuclear Training Manager - Seabrook Station
D. E. Carriere, Director, Production Services
L. M. Cuoco, Senior Nuclear Counsel
W. Fogg, Director, New Hampshire Office of Emergency Management
D. McElhinney, RAC Chairman, FEMA RI, Boston, Mass.
R. Backus, Esquire, Backus, Meyer and Solomon, New Hampshire
D. Brown-Couture, Director, Nuclear Safety, Massachusetts Emergency Management Agency
F. W. Getman, Jr., Vice President and General Counsel - Great Bay Power Corporation
R. Hallisey, Director, Dept. of Public Health, Commonwealth of Massachusetts
Seacoast Anti-Pollution League
D. Tefft, Administrator, Bureau of Radiological Health, State of New Hampshire
S. Comley, Executive Director, We the People of the United States
W. Meinert, Nuclear Engineer

Mr. Ted C. Feigenbaum i

Distribution w/encl:
H. Miller, RA/J. Wiggins, DRA
J. Linville, DRP
D. Lew, DRP
M. Oprendek, DRP
Region I Docket Room (with concurrences)
PUBLIC
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector

Distribution w/encl (VIA E-MAIL):
T. Bergman, RI EDO Coordinator
E. Adensam, PD I-3, NRR
J. Harrison, PD I-3, NRR
J. Clifford, NRR
B. Pulsifer, NRR
W. Scott, NRR
J. Wilcox, NRR
D. Screnci, PAO, ORA
Inspection Program Branch, NRR (IPAS)
DOCDESK

DOCUMENT NAME: C:\Seabrook99009.wpd
To receive a copy of this document, indicate in the box: "**C**" = Copy without attachment/enclosure "**E**" = Copy with attachment/enclosure "**N**" = No copy

OFFICE	RI/DRP		RI/DRP					
NAME	RLorson (jcl for)		JLinville					
DATE	**2/11/00**		**2/11/00**					

OFFICIAL RECORD COPY

U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.:	05000443
License No.:	NPF-86
Report No.:	05000443/99009
Licensee:	North Atlantic Energy Service Corporation
Facility:	Seabrook Generating Station, Unit 1
Location:	Post Office Box 300 Seabrook, New Hampshire 03874
Dates:	December 5, 1999 - January 16, 2000
Inspectors:	Raymond. Lorson, Senior Resident Inspector Javier Brand, Resident Inspector
Approved by:	James Linville, Chief Projects Branch 6 Division of Reactor Projects

EXECUTIVE SUMMARY

Seabrook Generating Station, Unit 1
NRC Inspection Report 05000443/99009

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6 week period of resident inspection.

Operations:

- Routine operations were performed well (Section O1). The licensee developed and implemented a comprehensive Year 2000 contingency plan. Some minor equipment problems occurred during the transition to Year 2000. These problems were promptly identified and corrected (Section O4.1).

- The operators performed a reactor down-power and start-up well. The licensee responded well, after identifying the problem, to minimize the adverse consequences associated with the intrusion of seawater into the steam generators. The event did not appear to have any immediate steam generator operability concerns (Section O4.2).

- Several operational deficiencies allowed an increased volume of seawater to enter the steam generators during a secondary chemistry event. Specifically, the operating procedure and existing management expectations enabled the operators to maintain the condensate lined up in preparation for placing an idle pump in-service for an extended period of time. Additionally, the operators were slow to respond to three condensate system alarms during the event. The licensee has initiated some corrective actions for this event including revision of the operating procedure, and is conducting a root cause evaluation (condition report 00-0125) to identify any additional corrective actions (Section O4.2).

- A regularly scheduled Nuclear Safety Audit Review Committee (NSARC) meeting effectively reviewed key station activities, and satisfied Technical Specification requirements (Section O7.1).

Maintenance:

- The maintenance activities to repair a nitrogen leak in the ‘A’ steam generator main feedwater isolation valve FW-V30 were performed well. Although the operator compensatory actions to perform this activity were planned and discussed, they were not documented on the on-line maintenance assessment. The licensee entered this documentation issue into their corrective action program (condition report 00-0729) (Section M1.1).

- Backseating charging valve CS-V154 did not appear to adversely impact the valve operability. The engineering controls for limiting the torque applied while backseating the valve were not implemented since a torque wrench was not used to perform this activity. The licensee reviewed this event (condition report 99-5018), and attributed the issue to unclear work instructions (Section M1.2).

- The licensee's investigation and corrective actions for slightly elevated vibration readings and iron particle concentrations in the lubricating oil reservoirs for both the 'A' and 'B' RHR pump motors were adequate but not successful. The licensee plans additional corrective actions (condition report 99-5171) to resolve these issues (Section M2.1).

Engineering:

- The licensee continued to properly investigate fuel assembly upper nozzle screw integrity issues to determine the root cause and required corrective actions. Additionally, the licensee concluded that newly identified holddown spring screw fractures do not adversely affect the reactor core (Section E2.1).

- The licensee's response to evaluate and correct a degraded turbine generator electrical overspeed trip system was appropriate (Section E 2.2).

TABLE OF CONTENTS

Report Details

Summary of Plant Status

The plant was operated at 100% power for most of the inspection period. On January 7, the operators reduced reactor power to remove the main turbine from service to replace the electric trip solenoid valve (Section E2.2). On January 9, the licensee shutdown the reactor to Mode 3 to remove sodium and chloride impurities from the steam generators per plant chemistry guidelines (Section O4.2). The licensee corrected the adverse secondary chemistry condition and performed a reactor start-up on January 10. The plant was returned to full power on January 12.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, routine operations were performed in accordance with station procedures and plant evolutions were completed in a deliberate manner with clear communications and effective oversight by shift supervision. Control room logs accurately reflected plant activities and observed shift turnovers were comprehensive and thoroughly addressed questions posed by the oncoming crew. Control room operators displayed good questioning perspectives prior to releasing work activities for field implementation. The inspectors found that operators were knowledgeable of plant and system status.

O2 Operational Status of Facilities and Equipment

General Comments (71707, 62707)

The inspectors routinely conducted independent plant tours and walkdowns of selected portions of safety-related systems during the inspection report period. These activities consisted of the verification that system configurations, power supplies, process parameters, support system availability, and current system operational status were consistent with Technical Specification (TS) requirements and UFSAR descriptions. Additionally, system, component, and general area material conditions and housekeeping status were noted. The inspectors did not identify any plant conditions that would have affected safety system operability.

O4 Operator Knowledge and Performance

O4.1 Year 2000 (Y2K) Readiness Review

a. Inspection Scope (71707)

The inspector reviewed the licensee's actions to support the safe transition to Year 2000. The inspector reviewed the Seabrook Station Millennium Project Integrated

Contingency Plan (ICP), and observed the station staff and equipment performance during the Y2K transition period.

b. Observations and Findings

The ICP included planning assumptions, staffing levels, training requirements, command and control responsibilities, and key transition activities. The ICP also included detailed checklists and instructions which tasked multiple field teams to inspect plant systems and equipment shortly after the Y2K transition. The inspector concluded that the ICP was comprehensive and provided adequate guidance to support the plant during the Y2K transition.

The plant staff professionally implemented the ICP during the Y2K transition. The inspector did not observe any problems that affected operating plant or safety system performance. Some problems were noted with support, and business-related systems including the equipment out of service system (EOOS), and the access control system. The inspector determined that these software-related problems were a minor nuisance, and did not adversely impact plant safety. The licensee promptly corrected these deficiencies.

c. Conclusions

The licensee developed and implemented a comprehensive Year 2000 contingency plan. Some minor equipment problems, which did not affect plant safety, were promptly identified and corrected during the transition to Year 2000.

O4.2 Plant Shutdown, Steam Generator Chemistry Excursion, and Start-Up

a. Inspection Scope (71707)

The inspector reviewed the operational activities associated with the plant power reduction on January 7, and the response to a steam generator chemistry problem that led to a plant shutdown on January 9. The inspectors also reviewed the subsequent plant start-up on January 10.

b. Observations and Findings

Plant Power Reduction

The operators initiated a planned power reduction on January 7 to replace the main turbine electric trip solenoid valve. The reactor power reduction was well controlled. The main turbine was removed from service and reactor power was stabilized at about 15% power on January 8, without any significant operational problems.

Secondary Chemistry Excursion and Plant Shutdown

At about 6:15 p.m., the operators subsequently lined up the “C” condensate pump to facilitate removal of the “B” condensate pump from service for maintenance. The line-up introduced a configuration where a check valve and single isolation valve provided the isolation barrier between the condensate and circulating water (CW) systems. The operators stopped the evolution (i.e did not start the condensate pump) to perform shift turnover activities. Three secondary system sodium alarms were received at 6:32 p.m., 8:09 p.m., and 8:16 p.m. after the condensate system was lined-up for the pump start, however, no actions were taken to investigate these alarms.

The condensate pump was started at 8:54 p.m. Shortly following the pump start, the operators received multiple secondary system sodium and conductivity alarms. The chemistry technicians investigated these alarms and determined that the steam generators (SGs) had elevated sodium and chloride concentrations which required a plant shutdown per chemistry procedure 3.2, “Secondary Chemistry Control Program”. The operators and chemistry technicians implemented several immediate corrective actions for this event including: clean-up of the secondary system and SGs, and shutdown of the plant to Mode 3. The licensee formed an event team to review this problem, and to identify the necessary corrective actions to be completed prior to the plant recovery.

The event team attributed the abnormal secondary chemistry levels to circulating water (CW) (i.e seawater) intrusion into the condenser hotwells. The seawater apparently entered the condenser hotwell due to a small amount of leakage (approximately 0.3 gallons) through the check valve and a single closed isolation valve. The event team report was thorough and identified several causal factors and corrective actions for this event. One of the causal factors that contributed to volume of seawater introduced into the condensate system was the amount of time that the condensate system was allowed to remain in the pump start line-up configuration. The licensee revised the applicable operating procedure to provide guidance directing the operators to limit the time in this configuration, and planned to review whether the decision to perform the line-up shortly before the planned shift turn-over was consistent with operations management expectations.

It appeared that the operators could have responded to this event sooner based on the sodium alarms that were received before the condensate pump was started. A more timely response to the initial alarms would have limited the severity of the SG chemistry problem. The inspector discussed these concerns with both the Chemistry Manager, and the Assistant Operations Manager who indicated that the root cause team for this event would review the operators’ response to these alarms.

The inspector questioned the impact of the chemistry excursion on the SG tube integrity. The licensee indicated that this event would have minimal impact on the SG tube integrity due to historically good performance of thermally treated tubes with respect to stress corrosion cracking, and also due to the low power level at which the event occurred. The licensee stated that these assumptions were confirmed by the SG vendor. The inspector discussed these factors with a materials specialist from Region I

and did not identify any immediate SG tube operability concerns. The inspector noted that subsequent SG samples have not shown any increase in SG activity levels.

Plant Start-Up Activities

The licensee established proper SG chemistry levels and initiated the reactor start-up on January 10. During the start-up, the operators observed a mismatch of about 6 steps between the indicated position of rod C-5, and the group position indication. The licensee performed troubleshooting and repaired the C-5 rod position indication circuitry. The start-up was completed without any further problems. The inspectors observed the start-up and noted that the operators controlled plant parameters well and maintained good communications during the start-up.

c. Conclusions

The operators performed a reactor down-power and start-up well. The licensee responded well, after identifying the problem, to minimize the adverse consequences associated with the intrusion of seawater into the steam generators. The event did not appear to have any immediate steam generator operability concerns.

Several operational deficiencies allowed an increased volume of seawater to enter the steam generators during a secondary chemistry event. Specifically, the operating procedure and existing management expectations enabled the operators to maintain the condensate lined up in preparation for placing an idle pump in-service for an extended period of time. Additionally, the operators were slow to respond to three condensate system alarms during the event. The licensee has initiated some corrective actions for this event including revision of the operating procedure, and is conducting a root cause evaluation (condition report 00-0125) to identify any additional corrective actions.

O7 Quality Assurance in Operations

O7.1 Nuclear Safety Audit Review Committee (NSARC) Meeting (71707)

Technical specification (TS) 6.4.3.1 requires the NSARC to independently review and audit designated activities important to plant safety. The inspectors observed selected portions of a regularly scheduled NSARC meeting held on December 8, 1999 and noted that the TS requirements were met regarding the committee composition, quorum, and topics reviewed. The technical presentations provided an adequate description of the plant issues discussed, and the NSARC members appeared to critically review each topic. The inspectors concluded that the NSARC meeting effectively reviewed key Station activities, and satisfied TS requirements.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Feedwater Valve Nitrogen Leak

a. Inspection Scope (62707)

On December 20, the inspector observed the licensee activities to repair a nitrogen leak from the 'A' steam generator main feedwater containment isolation valve (FW-V30). The leak was first identified on December 18, when a low nitrogen pressure alarm was received in the control room. The inspector attended the pre-job briefing, performed field walkdowns, and reviewed applicable documentation including the On-line Maintenance Assessment.

b. Observations and Findings

The feedwater containment isolation valves require pneumatic (nitrogen) pressure to close. The valves are designed to close on a feedwater isolation signal to prevent an uncontrolled plant cool-down following reactor trip, and also to prevent feeding a steam generator with an un-isolable steam leak.

The technician conducted a good pre-job brief. The inspector observed proper support from operations, including a discussion that isolation of the nitrogen supply line would prevent the valve from performing its safety-related containment isolation function. The licensee planned adequate compensatory measures to ensure isolation of the feedwater system piping, if required, by directing the operators to close/verify closed the main feedwater flow control, and isolation valves. The inspector noted that the compensatory operator actions were not documented in the on-line maintenance assessment evaluation. The inspector questioned whether adequate reviews of the compensatory actions had been completed prior to performing the work activities.

The inspector discussed this concern with a probabilistic risk assessment (PRA) engineer, and also with the on-line maintenance assessment program coordinator. The inspector confirmed that the FW-V30 nitrogen leak repair activities had been properly evaluated and determined to be of low risk significance in terms of the impact on core damage frequency and containment isolation system reliability. The work week manager stated that the on-line maintenance assessments typically include operator contingency actions.

c. Conclusion

The maintenance activities to repair a nitrogen leak in the 'A' steam generator main feedwater isolation valve FW-V30 were performed well. Although the operator compensatory actions to perform this activity were planned and discussed, they were not documented on the on-line maintenance assessment. The licensee entered this documentation issue into their corrective action program (condition report 00-0729).

M1.2 Charging Valve (CS-V154) Backseating Review

a. Inspection Scope (62707)

The inspector reviewed the controls established to ensure that backseating charging valve CS-V-154 would not adversely affect the ability to remotely close the valve.

b. Observations and Findings

Motor-operated valve CS-V154 can be remotely operated from the control room to isolate “D” reactor coolant pump seal injection flow. This valve is credited in the UFSAR as a containment isolation valve, however it does not automatically shut on a containment isolation signal. The licensee decided to manually backseat this valve to isolate a minor packing leak. The component engineer performed a calculation and determined that up to 38 ft-pounds of torque could be applied to the valve handwheel without affecting the valve operability.

The licensee provided the valve backseating instructions to the technician in work request (WR) 99W001375. The WR instructions incorporated the 38 ft-pound torque limit provided in the engineering calculation. The inspector reviewed the completed WR comments and interviewed the technician and noted that the valve was backseated manually in lieu of using a calibrated torque wrench. The technician indicated that minimal force was applied to the valve handwheel during the backseating operation. The inspector concluded that the applied torque was probably not excessive.

The inspector noted that the engineering controls for limiting the torque applied to this valve were not implemented as intended. The licensee agreed with this observation, and initiated a condition report (CR) to address this issue. The licensee later determined that the WR instructions did not clearly convey the engineering expectations to the worker. The inspector considered this response appropriate and noted that the unclear work instructions did not result in an inoperable valve condition.

c. Conclusions

Backseating charging valve CS-V154 did not appear to adversely impact the valve operability. The engineering controls for limiting the torque applied while backseating the valve were not implemented since a torque wrench was not used to perform this activity. The licensee reviewed this event (condition report 99-5018), and attributed this issue to unclear work instructions.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Residual Heat Removal Pump Vibration and Lubricating Oil Sample Results

a. Scope

The inspector evaluated the licensee's response to increased vibration readings identified by the licensee on both residual heat removal (RHR) pumps during scheduled quarterly surveillance testing in November 1999. The inspector also reviewed the licensee's response to indications of increased ferrous wear particles in the lubrication oil samples for both RHR pump motor bearings. The inspector interviewed personnel, reviewed documentation, performed field walkdowns, and observed portions of pump surveillance tests and collection of the oil samples.

b. Observations and Findings

The RHR system consists of two independent safety-related trains, each containing an RHR pump. The system is designed to cool the reactor during the second phase of plant cooldown following an accident, and during refueling operations.

Vibration data for the 'A" RHR pump was slightly higher than the normal 1 mil reading. The licensee has been investigating slightly elevated vibration readings on the 'B' RHR upper and lower motor bearings since the start-up from the May 1999 refueling outage. The licensee placed the pumps in an alert status and increased the surveillance test frequency from quarterly to once every 46 days per the in-service test program requirements.

The lubrication oil samples for both RHR pump motors taken in November, 1999, indicated higher than normal ferrous (iron) material and silica in the 'A' pump motor. The inspector noted that a similar condition had been identified and evaluated by the licensee in March 1999. This issue was originally evaluated and documented by the NRC in Inspection Report (IR) 99-01.

The licensee promptly issued condition reports and initiated a team cause and failure investigation to evaluate these concerns. Investigations determined that no immediate operability concern existed with either pump or motor, since all other applicable parameters such as flow, pressure and motor bearings temperature were normal.

The licensee performed a series of visual inspections for looseness, performed several pump runs and consulted with applicable vendors. These investigations determined that the slightly elevated vibration readings on the "A" RHR pump motor where due to errors introduced by the new vibration data collection equipment being used. The new equipment was more sensitive to the low frequency vibration readings than the previously used vibration equipment. The licensee decided to use the original test equipment until corrective actions are implemented to ensure proper use of the new equipment.

Investigation of the 'B' RHR pump and motor with the older vibration equipment indicated a slight increase in the motor lower radial bearing vibration 1.1 mils. Visual inspections of the visible areas of the upper motor bearing and housing did not reveal any significant looseness. At the completion of this inspection period the licensee had not completed its investigation of this issue, however, the licensee planned to replace the upper motor bearing during the next system work week, March 2000.

To address the lubricating oil issue, the licensee performed a series of oil flush and draining activities followed by subsequent pump runs and oil sampling. The new samples continued to show the elevated ferrous wear and silica particles. The licensee believes that the particles may be due to contact between the pump stationary bearing cap and the shaft bushing. The licensee indicated that the lubricating oil reservoir design limited the effectiveness of the oil flush. The licensee planned to inspect and clean the oil reservoir fully during the 'B' RHR pump upper motor bearing replacement.

c. Conclusion

The licensee's investigation and corrective actions for slightly elevated vibration readings and iron particle concentrations in the lubricating oil reservoirs for both the 'A' and 'B' RHR pump motors were appropriate but not successful. The licensee plans additional corrective actions (condition report 99-5171) to fully resolve these issues.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Fuel Assembly Upper Nozzle Screw Integrity Follow-up Inspections

a. Inspection Scope (37551)

The inspector performed a documentation review of inspections made by the fuel manufacturer (Westinghouse) and Seabrook personnel on several fuel assemblies stored in the spent fuel pool. The inspections were part of follow-up root cause investigation for failed screws identified by Westinghouse at another facility, and similar concerns identified at Seabrook during the April 1999 refueling outage.

b. Observations and Findings

During the last refueling outage (RFO6) Seabrook performed inspections of the fuel assembly upper nozzle spring mechanisms in response to a Westinghouse notification regarding latching problems during field movements at another facility. The inspection results were documented in Inspection Report 99-02. As discussed, Westinghouse evaluated the condition and concluded that failed screws could present fuel handling problems during refueling, but would not adversely affect the reactor core.

As part of the follow-up investigation, the licensee and Westinghouse performed enhanced testing on several of the fuel assemblies located in the spent fuel pool. This

testing, which was not available during the April refueling outage, was designed to provide a better indication of the upper nozzle assembly integrity. The test involved application of a slight upward force to the assembly spring to determine if the spring clamp was loose. The inspections indicated that ten assemblies (five Model "E" and five Model "F") had indications of fractured top nozzle spring screws, however, none showed any evidence of a total screw failure. Presently, 28 Model "E" and "F" assemblies are installed in the core. The licensee and Westinghouse personnel indicated that the current condition does not affect reactor safety. The licensee is reviewing additional corrective actions to resolve this issue.

c. Conclusion

The licensee continued to properly investigate fuel assembly upper nozzle screw integrity issues to determine the root cause and required corrective actions. Additionally, the licensee concluded that newly identified holddown spring screw fractures do not adversely affect the reactor core.

E2.2 Electric Trip Solenoid Valve Failure

a. Inspection Scope (37551)

The inspector reviewed the licensee's evaluation and response to repeat failures of the turbine generator electrical overspeed trip circuit to operate properly during testing on December 24, 1999, and on January 3, 2000.

b. Observations and Findings

The turbine generator overspeed trip circuit which consists of independent mechanical and electrical trip systems is designed to protect the turbine generator from an overspeed event. The electric trip circuit failed its initial test on December 24, 1999. The circuit passed a follow-up test, however, the licensee decided to increase the frequency of this testing. The electric trip circuit failed a second test on January 3, 2000, and the licensee elected to remove the turbine from service to replace the electric trip solenoid valve as discussed in Section O4.2.

The inspector attended several meetings, discussed the issue with the system engineer, and determined that the licensee's response to this issue was timely and appropriate. The electric trip solenoid valve was replaced on January 8, 2000, and the trip circuit was successfully tested. The system engineer indicated that the valve would be sent to an outside laboratory for a failure analysis.

c. Conclusion

The licensee's response to evaluate and correct a degraded turbine generator electrical overspeed trip system was timely and appropriate.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-443/98-013-01: valves not included within the scope of the in-service test (IST) program. This report supplemented information contained in LER 98-013 (reviewed in NRC Inspection Report 99-05), and identified three additional valves that had not been included within the scope of the IST program. The licensee identified these additional test program deficiencies while performing a generic IST program review as a corrective action for LER 98-013. The licensee added the three valves to the IST program and developed plans to test each valve. The inspector performed an in-office review of this event and concluded that the licensee's actions were reasonable and complete. This LER is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

The inspectors frequently toured the radiological controlled area (RCA) during the period and observed radiological work practices. The radiological controls technicians were observed to be attentive and provided high quality assistance to plant workers. Plant workers were observed to be following proper radiological work practices including the use of dosimetry and protective equipment. Personnel briefings conducted prior to job activities routinely emphasized precautions and instructions to limit exposure.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comment (71707, 71750)

The inspectors observed security force performance during inspection activities. Protected area access controls were found to be properly implemented during random observations. Proper escort control of visitors was observed. Security officers were alert and attentive to their duties.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors discussed the results of the inspection with licensee management on January 27, 2000. The licensee acknowledged the inspectors findings.

X2 Public Meeting Summary

NRC Regional Management met with members of the licensee's management at a public meeting in Seabrook, NH on December 17, 1999. The meeting agenda included a discussion of the latest NRC's plant performance assessment, and also the NRC's revised reactor oversight program.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

W. Diprofio, Unit Director
J. Grillo, Assistant Station Director
G. StPierre, Operations Manager
B. Seymour, Security Manager
T. Nichols, Technical Support Manager
D. Sherwin, Maintenance Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities

ITEMS OPENED, CLOSED, AND DISCUSSED

Closed:	LER 98-013-01: Valves not included within the scope of the In-service Test program.

PARTIAL LIST OF ACRONYMS USED

CAS	Central Alarm Station
CR	Condition Report
CW	Circulating Water
EOOS	Equipment Out of Service System
ICP	Integrated Contingency Plan
IST	In-service Testing
MOV	Motor operated valve
NSARC	Nuclear Safety and Audit Review Committee
QA	Quality Assurance
PRA	Probabilistic Risk Assessment
RHR	Residual Heat Removal
SG	Steam generator
SORC	Station Operations Review Committee
SW	Service Water
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
WR	Work request
Y2K	Year 2000