U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	50-336	50-423
Report Nos.:	99-06	99-06
License Nos.:	DPR-65	NPF-49

Licensee: Northeast Nuclear Energy Company
P. O. Box 128
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Facility: Millstone Nuclear Power Station, Units 2 and 3

Inspection at: Waterford, CT

Dates: April 20, 1999 - June 14, 1999

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Operations

- The licensee performed the Unit 2 startup and power ascension in a controlled and conservative manner following a shutdown which lasted in excess of three years. Operators performed evolutions slowly and deliberately and executed the power ascension without any significant events. Although communication between operators was a strength, examples of poor communication between operators and other work groups led to plant configuration changes without operator knowledge. During a pre-job brief an operator identified an inadequate surveillance for the atmospheric dump valves which if performed as written could have resulted in a reactor trip. Although it is good that operators are properly addressing these procedural issues as they arise, reliance on individuals performing the procedures to identify procedural deficiencies presents an unnecessary challenge to plant personnel. Line management and nuclear oversight maintained a strong presence in the control room and provided a positive influence on the conduct of operations. (Section U2.O1.2)

- On May 25, 1999, from operation at full power, operators initiated a manual reactor trip at Unit 2 when a steam leak developed in the turbine building as a result of a transient in the feedwater heaters. Operator performance in isolating the steam leak and placing the plant in a stable condition was good. The feedwater heater transient was caused by improper setup of the feedwater heater level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. The transient developed into a steam leak because generic engineering guidance for selecting torque values was improperly applied in the selection of torque values for the feedwater heater relief valve flange fasteners. The NRC found that the corrective actions implemented prior to restart were adequate to address the direct causes of the feedwater heater level control problems and the subsequent steam leak. Longer term corrective actions described in LER 50-336/99-009-00 to address the root causes were also acceptable. Therefore, LER 50-336/99-009 -00 is closed. No violation of NRC regulatory requirements occurred. (Section U2.O1.3)

- At Unit 2, the failure of the licensee to establish adequate procedural guidance for intentionally bypassing the automatic actuation of the engineered safeguards actuation system following issuance of a related 1992 NRC information notice is a violation of Technical Specification 6.8.1. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-336/99-06-01), consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into the corrective action program. Unresolved Item 50-336/96-09-09 is closed. (Section U2.O8.1)

- Operational evolutions in support of Unit 3 RFO6 were generally well controlled, with "defense in depth" considerations and departmental support of operational activities in evidence. Communications and shift turnover controls were adequate; although, as discussed by the inspectors with the responsible shift mangers, not always consistent with the expectations set by the conduct of operations protocol. (Section U3.O1.1)

- The licensee responded appropriately to the loss of Unit 3 main board annunciators, identified the cause and recovered from event in a timely manner, and appropriately restored the electrical alignment to normal prior to the continuation of testing. (Section U3.O1.2)

- A number of problems in Unit 3 configuration and work control were identified by either Nuclear Oversight or the line organizations or were self-revealing during this inspection period. Licensee management addressed these concerns with more rigorous process controls, along with a stronger management focus on these issues. Inspector follow-up of licensee and NO corrective measures, as well as the actions taken to address the technical problems documented in several CRs and ODs appeared to apply appropriate focus on the identified concerns. (Section U3.O2.1)

Maintenance

- Unit 3 Surveillance testing was conducted in accordance with established procedures. Good coordination was observed between control room operators and the responsible engineering personnel in support of the testing activities, system lineups, and disposition of test results. Where appropriate, technical expertise was obtained to confirm that the surveillance test data was consistent with the acceptance criteria. (Section U3.M1.1)

- Unit 3 inservice inspection was performed acceptably and included appropriate ASME program coverage, qualified personnel, approved procedures, proper implementation, acceptable examination documentation, and NU oversight. The inspections performed were thorough and of sufficient extent to determine the integrity of the components inspected. (Section U3.M2.1)

- Eddy current testing of Unit 3 steam generator tubes observed included acceptable procedures, qualified personnel, proper implementation, appropriate examination documentation and adequate NU oversight. The inspections performed were thorough and of sufficient extent to determine the integrity of the tubes inspected. When identified, nonconforming conditions were verified by use of alternate probe types, characterized, sized and properly dispositioned in accordance with established requirements. (Section U3.M2.2)

- The failure to properly test the Unit 1 main stack noble gas monitor is a violation of Unit 3 TS Table 4.3-9 This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (NCV 50-423/99-06-03). (Section U3.M8.1)

- The failure to test Unit 3 low pressure safety injection check valve 3SIL*V15 in 1995 in accordance with TS 4.0.5 is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (NCV 50-423/99-06-04). (Section U3.M8.2)

- The failure to properly calibrate the meteorological monitoring wind speed channel is a violation of TS 4.3.3.4. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (NCV 50-423/99-06-05). (Section U3.M8.3)

- The failure to properly test the Unit 3 RHR suction valve 3RHS*MV8702B as followup testing to the 1989 test results is a violation of TS 4.4.6.2.2.e. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (NCV 50-423/99-06-06). (Section U3.M8.4)

- The failure to properly test the Unit 3 P-4 logic prior to 1996 is a violation of TS 3.2.2. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (NCV 50-423/99-06-07). (Section U3.M8.5)

Engineering

- At Unit 2, the failure of the licensee to perform design reviews of temporary modifications that were installed through plant procedures 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 (NCV 50-336/99-06-02), consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into the corrective action program. The licensee's plan to complete the required design reviews prior to installation and as part of the biannual review of procedures was acceptable. Unresolved Item 50-336/98-208-02 is closed. (Section U2.E8.2)

- The failure to perform Unit 3 ISI pressure tests earlier in the first 10 year inspection interval for 2 ASME systems and 17 containment isolation valves is a violation of technical specification (TS) 4.0.5. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (NCV 50-423/99-06-08). (Section U3.E8.1)

- The failure to perform the required Unit 3 ASME Section XI examinations in 10 separate ASME systems in 1989 and 1995 is a violation of TS 4.0.5. This Severity Level IV violation is being treated as a Non-cited Violation consistent with Appendix C of the NRC Enforcement Policy (NCV 50-423/99-06-09). (Section U3.E8.2)

Plant Support

- Two condition reports were written during the Unit 3 refueling outage that documented violations of Technical Specification 6.12.1 high radiation area entry requirements. Both instances involved the use of alarming dosimeters that alarmed after reaching the preset integrated dose value, but were not audible to the worker and resulted in additional exposure to personnel. Both instances were identified by the licensee. Effective short term corrective actions were taken, and long term actions were initiated to evaluate other instrumentation options. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-423/99-06-10), consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into their corrective action program. This violation is in the licensee's corrective action program as Condition Reports M3-99-1390 and M3-99-1525. (Section R1.1)

Report Details

Summary of Unit 2 Status

Unit 2 entered the inspection period in Operational Mode 5, cold shutdown, with repairs to address pressure seal leakage from the reactor coolant system to shutdown cooling system suction isolation valve in progress. When the licensee completed repairs to the valve, the licensee used reactor coolant pump heat to bring the plant to normal operating pressure and temperature in Operational Mode 3, hot standby.

The unit was initially shut down on February 20, 1996, to address containment sump screen concerns and has remained shut down to address the problems outlined in the Restart Assessment Plan and a NRC Demand for Information [10 CFR 50.54(f)] letter requiring an assertion by the licensee that future operations will be conducted in accordance with the regulations, the license, and the Final Safety Analysis Report. On April 29, 1999, the NRC informed the licensee that the terms of an August 1996 order requiring an independent corrective action verification program had been satisfied and that restart of Unit 2 was authorized.

The licensee entered Operational Mode 2, Startup, and brought the reactor critical on May 9, 1999. Subsequently, the licensee entered Operational Mode 1, Power Operation, conducted low power testing, and initiated a planned power ascension, which had hold-points at 30, 50, 75, and 90 percent power. The plant reached 100 percent power on May 19, 1999.

On May 25, 1999, Unit 2 operators initiated a manual reactor trip from 100 percent power and closed the main steam isolation valves following feedwater system transients and a report of a steam leak in the turbine building. The plant responded normally to the trip, and operators stabilized the plant in Operational Mode 3, Hot Standby, at normal operating temperature and pressure. After addressing problems with the feedwater heaters, the licensee entered Operational Mode 2, Startup, and brought the reactor critical on May 28, 1999. The plant returned to 100 percent power on May 31, 1999. At the conclusion of the inspection period, the plant remained in operation at 100 percent power.

U2.I Operations

U2 O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspector conducted frequent reviews of ongoing plant operations, including observations of operator evolutions in the control room; walkdowns of the main control boards; tours of the Unit 2 radiologically controlled area and other buildings housing safety-related equipment; and observations of several management planning and oversight committee meetings.

The inspector observed operational preparations, procedural adherence, and conformance with technical specification requirements during portions of the following evolutions: plant heatup to normal operating temperature, steady-state operation at power, and startup and power ascension following the reactor trip. The operators conducted these evolutions well. The inspectors noted good communication practices and adherence to operating procedures.

O1.2 Startup and Power Ascension from an Extended Outage

a. Inspection Scope (71715/71707)

Following the extended shutdown of Unit 2, which lasted for over three years, the NRC conducted sustained inspections of control room activities at Unit 2 from just prior to entry into Operational Mode 2, Startup, through the power ascension to stable operation at full power. The inspectors observed operator performance with respect to control of evolutions, alarm response, procedural adherence, and communications. The inspectors monitored the execution of special procedure (SPROC) OP98-2-08, "Unit 2 Restart Following 10CFR50.54(f) Outage," and other applicable operating procedures (e.g., OP-2202, "Reactor Startup," and OP-2203, "Plant Startup"). The inspectors also interviewed operations shift managers and line managers that were providing oversight of operations.

b. Observations and Findings

At Unit 2, operators brought the plant into Operational Mode 2, Startup, and brought the reactor critical on May 9, 1999. In accordance with special procedure (SPROC) OP98-2-08, operators completed various tests at low power before bringing the plant to the first planned hold point at 30 percent power. Additional hold points were established at 50, 75, and 90 percent power plateaus. At each hold point, plant management and Nuclear Oversight reviewed plant status and newly identified issues. The licensee and the NRC discussed plant status, newly identified technical issues, and Nuclear Oversight assessments at each of the hold points by conference call. On May 15, 1999, the NRC concurred with continuing the power ascension from 30 percent power. At each of the subsequent hold points, the NRC also concurred with continuing the power ascension. On May 19, 1999, the plant reached 100 percent power, and the licensee and the NRC held a final discussion to assess the power ascension.

During startup and power ascension, the inspectors found operator performance and knowledge to be generally good. Operators performed evolutions slowly and deliberately during the startup and during other significant reactivity manipulations. Operators executed the power ascension without any significant events. However, the inspectors observed one minor operational event demonstrating a weakness in operational experience. While reducing power from 30 to 10% to take the generator off-line for turbine overspeed testing, high steam generator water level caused an automatic turbine trip. The steam generator level transient was induced when operators changed the mode of operation of the feedwater flow control valves. The licensee determined that this event was caused by unclear procedural guidance regarding when to change the mode of operation of the feedwater flow control valves. The operators' lack of recent training or experience in operating the feedwater system during a shutdown contributed to the event. The inspector reviewed the procedural guidance and determined that although the procedure was not inadequate, it could be clarified to minimize the possibility of future misinterpretation.

The inspectors found that operations briefings were conducted well. Shift turnovers and briefings effectively communicated plant status and plans for the shift. Observed pre-evolution briefings were thorough and communicated appropriate information regarding the purpose of the evolution, termination criteria, personnel responsibilities, communication practices, and procedural adherence. Operators were attentive to the information presented during the briefs. This behavior was demonstrated by operator identification of two significant errors in surveillance procedure SP2610E, "MSIV Closure and Main Steam Valve Operational Readiness Testing," regarding in-service testing for the steam generator atmospheric dump valves. The operator found the following errors in the procedure: as a result of a typographical error, the procedure failed to direct the isolation of the correct valve to block steam relief through the steam generator atmospheric dump valves during surveillance testing and the procedure failed to direct the restoration of the steam generator atmospheric dump valve controls to their correct configuration for automatic operation. These errors are important because operation of the atmospheric dump valves without the associated block valve closed could have caused a reactor trip and because improper restoration of the controller would prevent the dump valves from performing their design function of mitigating steam generator pressure transients following a turbine trip. The licensee entered these errors into the corrective action program as condition report M2-99-1665. These procedural errors were not found to be violations of NRC regulatory requirements because the atmospheric dump valves are not classified as safety-related components.

Throughout the startup and power ascension, the inspectors observed good communication practices among the plant operators. Operators promptly reported illuminated annunciators and implemented the appropriate alarm response procedures. Conversely, the inspectors noted a series of communication problems between operations personnel and other work groups that led to inappropriate changes in plant status or configuration as demonstrated in the following examples:

(1) Chemistry changed condensate resin columns without informing operators. These actions resulted in unexpected condensate conductivity alarms, which prompted unnecessary operator response.

(2) Following authorized troubleshooting activities to investigate why the output contactor for the No. 2 rod control motor generator opened and while the reactor was critical, field workers paralleled the No. 2 motor generator with the operating 1 motor generator without informing control room operators. Operators were sensitive to this activity because of the potential to cause the output contactors for both motor generator sets to open, which would result in a reactor trip.

(3) Based on a statement made during a management meeting that steam generator chemistry was satisfactory for operation at 30 percent power, operators concluded that a procedure step requiring satisfactory chemistry for power increase above 20 percent was satisfied and began increasing power. However,

when the plant was at 23 percent power, chemistry notified the operators that condensate dissolved oxygen was not satisfactory for operation above 20 percent power. Operators had not obtained a direct report from chemistry that all parameters were satisfactory for operation above 20 percent power before initiating the power increase.

Based on these examples, the inspectors found communication between operators and other work groups to be weak. Accurate and complete communication of activities is important so that operators are aware of the condition of plant equipment, prepared for potential events, and ready for anticipated alarms during routine evolutions.

The inspectors found management involvement in the startup and power ascension to be a positive factor. The development of the special procedure provided a good mechanism to coordinate the overall sequence of actions and procedure implementation. Throughout the startup and power ascension, the inspectors observed line management presence in the control room, including frequent oversight by senior line managers.

Nuclear Oversight developed a startup and power ascension assessment plan, which was successfully implemented. Nuclear Oversight provided near continuous observation of control room activities throughout the power ascension. The inspectors found that line management was receptive to nuclear oversight comments and concerns.

c. Conclusions

The licensee performed the Unit 2 startup and power ascension in a controlled and conservative manner following a shutdown which lasted in excess of three years. Operators performed evolutions slowly and deliberately and executed the power ascension without any significant events. Although communication between operators was a strength, examples of poor communication between operators and other work groups led to plant configuration changes without operator knowledge. During a pre-job brief an operator identified an inadequate surveillance for the atmospheric dump valves which if performed as written could have resulted in a reactor trip. Although it is good that operators are properly addressing these procedural issues as they arise, reliance on individuals performing the procedures to identify procedural deficiencies presents an unnecessary challenge to plant personnel. Line management and nuclear oversight maintained a strong presence in the control room and provided a positive influence on the conduct of operations.

O1.3 (Closed) LER 50-336/99-009-00: Manual Reactor Trip due to Steam Leak in the Turbine Building

a. Inspection Scope (93702/92700)

The inspector reviewed the circumstances surrounding a manual reactor trip that was prompted by feedwater system transients and a subsequent report of a steam leak in the turbine building. Inspection activities included a review of the licensee's assessment of the cause of the feedwater system transients and the steam leak, a review of the licensee's corrective actions, and an on-site review of the associated licensee event report, LER 50-336/99-009-00. In addition, the inspector monitored plant restart and the operation of the feedwater system after implementation of corrective actions.

b. Observations and Findings

At 3:12 p.m. on May 25, 1999, operators manually tripped the Unit 2 reactor after experiencing feedwater system transients and receiving a report of a steam leak in the turbine building. The plant responded to the trip as designed with no complications. Operators isolated the steam supply to the turbine building to ensure the steam leak would be isolated. At the completion of the operator's standard post-trip actions, Unit 2 was stable in Operational Mode 3, hot standby, at normal operating pressure and temperature. Decay heat removal was provided by the steam generators using auxiliary feedwater and the atmospheric steam dump valves. There were no injuries as a result of the steam leak.

The source of the steam leak was the inlet flange on the pressure relief valve for the 1A feedwater heater shell. The 1A heater is the first heater downstream of the "A" main feedwater pump and the last heater upstream of the steam generators. Due to improperly functioning level control valves in the 1A and 2A heaters, the 1A heater pressure increased and lifted the relief valve. The licensee believes that the moment resulting from steam discharge through the relief valve tailpiece relieved the compressive force on one side of the relief valve inlet flange. This condition allowed the steam pressure to eject the flange gasket material, which created a path for the steam leak.

The feedwater system problems that led to this event began affecting plant operation following main turbine valve testing early in the morning on May 25, 1999. At that time, the 2A feedwater heater experienced erratic level control that resulted in heater level cycling between the high and low level alarm setpoints 48 times over a 96 minute period. At the end of this period, water level in the 2A heater increased to a level that initiated an automatic closure of certain supply valves, but operators promptly took manual control of the affected valves and, when levels were stable, restored automatic level control for the 2A heater. During this transient, operators noted the sluggish response of the 2A heater normal level control valve, which directs water from the 2A heater to the heater drain tank. Later that day, maintenance lubricated the valve stem and tested the operation of the valve with satisfactory results.

Despite these maintenance actions, the 2A heater again experienced erratic level control that afternoon. This transient generated a series of about 20 heater low level alarms in the control room over a 35 minute period. In response to these alarms, control room operators entered the associated alarm response procedure, contacted instrumentation and control technicians for assistance, dispatched equipment operators to evaluate local conditions at the feedwater heaters, and initiated a power reduction.

At the end of the second series of low level alarms from the 2A heater, the water level in the 2A heater increased above the high level alarm setpoint. At this time, the equipment operators noted that the 2A heater water level was out-of-sight high. By design, this condition caused an automatic closure of the 1A heater normal level control valve, which stopped the flow of water from the 1A heater to the 2A heater. This valve closure caused the level in the 1A heater to increase to its high level alarm setpoint. At the observed water levels in the heaters, both the 1A heater and 2A heater high level dump valves should have been fully open. However, because of an improper controller setup, the 2A heater high level dump valve remained closed and the 1A heater high level dump valve was less than half open.

With the 1A heater normal level control valve closed and the 1A heater high level dump valve less than half open, the 1A heater shell filled above the high-high level setpoint. This condition resulted in isolation of the extraction steam supply to the 1A heater shell. However, two other supplies to the 1A heater shell, the first and second stage reheater drains, were not designed to isolate on high level in the 1A heater. Shortly after the equipment operators completed their observations at the feedwater heaters, the relief valve for the 1A heater lifted. The flow from the first and second stage reheater drains, which are at pressures of 850 psig and 470 psig, respectively, exceeded the capacity of the partially open dump valve and pressurized the 1A feedwater heater shell to its relief valve lift pressure of 450 psig. When the relief valve inlet flange gasket subsequently failed, the equipment operators reported the steam leak to the control room and the Shift Manager directed control room operators to manually trip the reactor. The inspector observed control room activities shortly following the reactor trip and found that operator performance in isolating the steam leak and placing the plant in a stable condition was good.

The licensee maintained the plant in Operational Mode 3, hot standby, while assessing the cause of the trip. The focus of the licensee's investigation involved identifying the cause of the feedwater heater problems and identifying the cause of the relief valve flange gasket failure.

The licensee determined that the feedwater heater problems were caused by improper setup of the level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. The heater level control system uses a single pneumatic controller with a narrow level control band to position the normal level control valve and high level dump valve for each heater. These valves were intended to operate sequentially based on the pressure output of the pneumatic controller. However, the normal level setpoint for the 1A and 2A heaters had been set high in the available control band to prevent frequent low level alarms. This condition reduced the maximum output of the pneumatic controller to the point that the pressure was insufficient to fully open the high level dump valves. Although sluggish response of the normal level control valve for the 2A heater apparently initiated the heater level transient, the licensee determined that proper functioning of the high level dump valve would have prevented the system transient that led to the plant trip.

As a short-term corrective action to address the feedwater system problems, the licensee changed the control scheme such that the level control valves respond more quickly to changes in heater level and the high level dump valve operation overlaps the normal level control valve operation. This allows the high level dump valves to fully open as necessary. The licensee also adjusted and tested the normal level control valve for the 2A heater to ensure it operates properly. This event was classified as a Maintenance Preventable Functional Failure for the feedwater heater vents and drains system. The inspector found these short-term corrective actions acceptable to support restart.

The license determined that the failure of the relief valve flange gasket resulted from the improper application of engineering guidance for establishing torque values for the flange fasteners. This generic guidance did not consider the loading applied to flanges by relief valve actuation. As short-term corrective actions, the licensee inspected the 2A feedwater heater and associated equipment, completed necessary repairs, and reinstalled the equipment. The licensee also evaluated the torque values used in similar applications to ensure that the torque values were adequate for expected transient load combinations. The inspector found these corrective actions acceptable to address concerns regarding the flange gasket failure.

The licensee submitted LER 50-336/99-009-00 that addressed the reactor trip. This LER included commitments to establish appropriate controls for setup of the feedwater heater level control system and to revise the generic engineering guidance for torquing of fasteners. These corrective actions were included in the licensee's corrective action program as condition report M2-99-1730. The inspector found these long-term corrective actions acceptable. Although the concerns with the improper setup of the feedwater heater level control system are similar to past configuration control concerns, the non-safety-related classification of the feedwater heater level control system places the issue outside the scope of recovery efforts at Millstone and outside regulatory requirements for procedural controls. Therefore, no violation of NRC requirements occurred.

c. <u>Conclusions</u>

From operation at full power, operators initiated a manual reactor trip when a steam leak developed in the turbine building as a result of a transient in the feedwater heaters. Operator performance in isolating the steam leak and placing the plant in a stable condition was good. The feedwater heater transient was caused by improper setup of the feedwater heater level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. The transient developed into a steam leak because generic engineering guidance for selecting torque values was improperly applied in the selection of torque values for the feedwater heater relief valve flange fasteners. The NRC found that the corrective actions implemented prior to restart were adequate to address the direct causes of the feedwater heater level control problems and the subsequent steam leak. Longer term corrective actions described in LER 50-336/99-009-00 to address the root causes are also acceptable. Therefore, LER 50-336/99-009 -00 is **closed**. No violation of NRC regulatory requirements occurred.

U2 O8 Miscellaneous Operations Issues

O8.1 (Closed) Unresolved Item 50-336/96-09-09: Override of Safety Injection Actuation Signal

a. Inspection Scope (92 '01)

The inspector reviewed the licensee's corrective actions to address Unresolved Item 50-336/96-09-09. This item involved weaknesses in operating procedures and unclear management expectations as to when operators may override an automatic Safety Initiation Actuation Signal (SIAS).

b. Observations and Findings

This concern was identified by the NRC during the licensee's annual Emergency Planning exercise in 1996, which used a postulated steam generator tube rupture as the initiating event. During the exercise, operators discussed on several occasions whether they should override the automatic actuation of SIAS. The inspector raised this concern because NRC Information Notice 92-47, "Intentional Bypassing of Automatic Actuation of Plant Protective Features," had been issued to alert licensees to the importance NRC attached to "having formal criteria and training regarding limitations on bypassing plant protective features."

The licensee issued Condition Report M2-97-0370 to address the concern. Corrective actions included revising procedure OP 2255, "Abnormal Operating Procedure User's Guide," and procedure OP 2260, "Emergency Operating Procedure User's Guide," to direct the operators that Engineered Safeguards Actuation System (ESAS) signals are to be blocked only when the operators have control of the plant and are intentionally causing parameters to approach ESAS setpoints. This guidance was also added to procedures that could involve the blocking of an ESAS signal such as procedure EOP 2534 "Steam Generator Tube Rupture." Training of operators on the new guidance began in January 1999 after completion of a major revision to the procedures.

c. Conclusion

The failure of the licensee to establish adequate procedural guidance for intentionally bypassing the automatic actuation of ESAS following issuance of a related 1992 NRC information notice is a violation of Technical Specification 6.8.1. This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-06-01)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into their corrective action program. Unresolved Item 50-336/96-09-09 is **closed**.

U2.II Maintenance

U2 M1 Conduct of Maintenance

M1.1 General Maintenance Observations

a. Inspection Scope (62707)

During routine plant inspection tours, the inspectors observed, on a random sampling basis, maintenance and surveillance activities to evaluate the propriety of the activities and the functionality of systems and components with respect to technical specifications and other requirements.

b. Observations and Findings

The inspectors reviewed maintenance work orders and interviewed licensee field personnel to verify the adequacy of work controls. The inspector observed a portion of activities performed under the following automated work orders (AWOs):

- AWO M2-99-05878 Troubleshoot and Repair Control Element Assembly 65 Power Supply
- AWO M2-99-06227 Adjust Voltage Output for Control Element Assembly 62
- AWO M2-99-05882 Replacement of "C" Reactor Building Closed Cooling Water Heat Exchanger Service Water Outlet Spool
- AWO M2-99-005604 Repair of the Service Water Pipe from the 'C' Reactor Building Closed Cooling Water Heat Exchanger

The inspector found that maintenance work was being performed in accordance with approved work orders present at the work site. A review of the work packages found that they were complete with respect to work authorizations, procedures, and inspection requirements.

Control Element Assembly (CEA) 65 failed to respond to test signals during startup preparations on May 9, 1999. The licensee determined that a power supply fuse had blown, which interrupted power to the rod. The same circuit had experienced a blown fuse during testing on April 28, 1999. Under AWO M2-99-05878, the licensee replaced the five coil programmer power switch modules for CEA 65 that are controlled by the affected circuit in addition to the fuse. Although testing of the removed modules failed to identify a cause for the blown fuses, the circuit has functioned without failure through two reactor startups since the module replacement. The licensee appropriately classified this second blown fuse, which delayed restart, as a Maintenance Preventable Functional Failure.

During power ascension on May 16, 1999, CEA 62 slipped several steps while withdrawing the regulating group of rods that includes CEA 62. Instrumentation and Control (I&C) technicians determined that the apparent cause was low output voltage to the coils. The inspector found that the I&C technicians employed appropriate vendor guidance in adjusting the output voltage under AWO M2-99-06227. The as-found voltage profiles for some of the coils were below the vendor recommended profiles. After adjusting the voltage, the CEA functioned properly during a subsequent reactor startup.

On May 3, 1999, operators identified a through-wall leak in the "C" reactor building closed cooling water (RBCCW) heat exchanger service water outlet spool. The licensee determined that this spool and similar spools associated with the "A" and "B" RBCCW heat exchangers remained operable based on ultrasonic testing and evaluation of the discrete, pin-hole nature of the defects in this spool. The licensee replaced the spool with a spool of similar construction, but the replacement spool was lined with an epoxy material to preclude similar pitting corrosion. The inspector discussed the repairs with the system engineer and observed the defects in the spool that was removed. The inspector found that the licensee adequately evaluated the operability of the existing and replacement spools installed in the system. The licensee appropriately classified the through-wall leak in the spool as a Maintenance Preventable Functional Failure.

c. Conclusions

The inspectors concluded that the work performed under the listed maintenance work orders was acceptable. The licensee appropriately evaluated component failures with respect to maintenance rule program criteria.

M1.2 Installation of Instrument Air Tubing Supports Associated with Service Water Strainer Backwash Valves

a. Inspection Scope (62707)

The inspector reviewed the documentation associated with Automated Work Order (AWO) M2-99-03782, which installed Unistrut supports on two instrument air tubing lines that supply air to the "A" and "B" service water strainer backwash valves, 2-SW-90A and 2-SW-90B, respectively. Specifically, the inspector evaluated whether engineering documentation should have been generated to support the maintenance activity.

b. Observations and Findings

On March 23, 1999, the licensee performed AWO M2-99-03782 which specified installing Unistrut supports upstream of valves 2-IA-67 and 2-IA-68, the root valves in the instrument air supply lines to backwash valves 2-SW-90A and B, respectively. The inspector noted that the work was performed with no engineering documentation such as a drawing change, a Design Change Notice (DCN), or Maintenance Support Engineering Evaluations (MSEEs). The inspector evaluated whether this engineering documentation was required and whether the specific locations of the supports needed to be delineated and analyzed.

Although the backwash valves are safety-related, Seismic Class I components, the instrument air supply lines to the backwash valves are Seismic Class II (non-seismic) because: (1) A loss of instrument air would cause the backwash valves to open resulting in the continuous backwash of the service water strainers to clear debris, which does not affect service water system operability and; (2) The instrument air supply to the backwash valves is not connected to the process piping and therefore the failure of the instrument line would not cause a service water system leak. Although Seismic Class I instrument tubing is installed and supported as detailed in specification 7604-MS-66, "Design Guide for Seismic Class I Instrument Tubing Installation," there is no specific guidance for the installation of Seismic Class II instrument tubing. Therefore, for Seismic Class II tubing, there is no requirement to develop a specific isometric drawing that delineates the specific location of the supports and the seismic adequacy of the installation is not required to be analyzed.

Discussion with engineering personnel indicated that although specification 7604-MS-66 applied to Seismic Class I applications, for lack of any other available guideline, the spacing criteria (maximum unsupported span 3 feet) for the supports was also typically used for Seismic Class II applications. The inspector walked down the instrument air lines that supply the backwash valves and found that the although the maximum unsupported span was greater than three feet in some instances the air lines appeared to be adequately supported.

The inspector also reviewed the Design Control Manual, Chapter 1, Section 1.8, which describes Maintenance Support Engineering Evaluations (MSEEs). MSEEs are developed by Maintenance and Operations as part of the work planning process to make minor configuration changes which makes use of the flexibility with the existing approved design. These changes must be authorized by engineering prior to performing work. Engineering approval is documented by the issuance of a design change notice (DCN) along with a 10CFR50.59 safety evaluation screening form. The inspector determined that the licensee decision to not prepare an MSEE to install the supports on the instrument air lines was acceptable because no drawing change was needed and the installation of the supports did not modify the plant configuration in a manner that was inconsistent with the original design.

c. Conclusions

The NRC agreed with the licensee's determination that no engineering documentation (MSEE, DCN, drawing change) was needed to install Unistrut supports on two instrument air tubing lines that supply air to the "A" and "B" service water strainer backwash valves.

U2.III Engineering

U2 E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 50-336/96-06-07: Refueling Pool Drain Line Seismic Issues

a. Inspection Scope (92903)

The inspector reviewed the licensee's corrective actions to address Unresolved Item 50-336/96-06-07.

b. Observations and Findings

Unresolved Item 50-336/96-06-07 involved the non seismic piping that was connected to the refueling pool drain header which was used for refueling pool water purification during refueling. The concern was that if a seismic event were to occur during refueling, this could result in a failure of this non seismic piping and draining of the refuel pool to the containment sump. Two 4-inch refueling pool drain lines, each containing a manual isolation valve, 2-RW-123 & 124, join to form a common 4-inch header that directs water to the suction of the refueling water purification pumps. The piping upstream of valves 2-RW-123 & 124 was seismically qualified but a 31 foot section of piping downstream of the valves was non seismic.

As an interim corrective action, the licensee revised Operations Procedures OP 2305, "Spent Fuel Pool Cooling and Purification System" and OP 2209A, "Refueling Operations," to lock closed valves 2-RW-123 & 124 before and during core off-load and reload activities. To permanently address the concern, the licensee modified the supports for the 31-foot non seismic portion of the refueling pool purification piping to establish acceptable stress conditions for all postulated conditions, including seismic (DCN DM2-00-1399-97). Based on these design changes, the purification system can now be operated continuously during refueling.

c. Conclusions

The licensee's corrective actions were found appropriate and Unresolved Item 50-336/96-06-07 is **closed**. This concern did not involve a violation of NRC requirements.

E8.2 (Closed) Unresolved Item 50-336/98-208-02; Procedurally Implemented Temporary Modifications

a. Inspection Scope (92903)

The inspector reviewed the licensee's corrective actions to address Unresolved Item 50-336/98-208-02.

b. Observations and Findings

Unresolved Item 50-336/98-208-02 involved instances where temporary modifications implemented through approved plant procedures, such as operating and surveillance procedures, had not received the design reviews and controls to verify the adequacy of the design changes. Procedure WC-10, "Temporary Modifications," provides the instructions for review and control of temporary modifications. However, the licensee had not been using this procedure for temporary modifications that were installed and controlled by approved plant procedures.

Condition Report M3-97-4556 was issued to address the concern. The licensee performed the required reviews of the temporary modifications that were installed at the time. As a long term corrective action, procedure MP-05-DC-FAP01.1, "Developing and Modifying Manuals, Procedures, Guidelines, Handbooks, and Forms," Section 2.4, "Performing the Biennial Review on Procedures and Forms," was changed to require design review per procedure WC-10 for documents containing proceduralized temporary modifications. This assures that within next two years all plant procedures containing temporary modifications will be revised to include the design review and control provisions of procedure WC-10. In the interim, the licensee has issued Night Order Number 2-8-99-1 which states WC-10 reviews are required for temporary modifications to be implemented using approved plant procedures. This Night Order also enforces revisions of the plant procedure(s) used at the time to reflect changes requiring review and control provisions given in WC-10.

Thus far, the licensee has completed revisions of sixteen plant procedures to include design review and control provisions of procedure WC-10 and two other plant procedures are in the process of being revised. The inspector found three existing procedure-driven temporary modifications present in the Unit 2 control room and verified that the operating procedures associated with these temporary modifications (OP2331, OP2336A, and OP2340A) were updated to include review and control provisions of procedure WC-10.

c. Conclusions

The failure of the licensee to perform design reviews of temporary modifications that were installed through plant procedures 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 (NCV 50-336/99-06-02)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into the corrective action program. The licensee's plan to complete the required design reviews prior to installation and as part of the biannual review of procedures was acceptable. Unresolved Item 50-336/98-208-02 is **closed**.

Report Details

Summary of Unit 3 Status

Unit 3 began the inspection period at approximately 100 percent power. On April 24 operators reduced power to 95 percent to perform thermal backwashes of the six circulating water bays. Upon completion of all except the "B" bay due to traveling screen problems, operators restored the reactor to 100% power the following day.

On April 29 operators commenced a reactor downpower to 75 percent to perform testing on the motor driven main feedwater pump. Upon completion of this testing on April 30, operators further reduced power to 50% to perform main steam valve testing. Operators subsequently shut down the reactor on May 1 to begin refueling outage number 6 (RFO6). Unit 3 was placed in Mode 6 (refueling - average coolant temperature less thank or equal to 140 degrees Fahrenheit) on May 9. On May 20, fuel handlers completed a full core offload into the spent fuel pool. From June 1 through June 5 fuel handlers reloaded the fuel into the reactor vessel. The plant remained in Mode 6 through the end of the report period on June 14.

On April 20 licensee managers met with NRC Region I managers in the Region I offices in King of Prussia to discuss Unit 3 refueling outage six (RFO6) plans. The licensee's slides used during the meeting are attached.

U3.I Operations

U3 O1 Conduct of Operations

O1.1 Extended Control Room Observations

a. Inspection Scope (60710, 71707, 71715)

During the Unit 3 downpower, component and system testing, and plant shutdown activities commencing the start of refueling outage number 6 (RFO6), NRC inspectors conducted round-the-clock observations in the control room. Inspection activities were coordinated with ongoing operational evolutions; including the review of procedures, assessment of control room protocol and communications, and overall observation and evaluation of operations conduct and performance.

b. Observations and Findings

The inspectors witnessed shift turnover activities, performed plant inspection-tours on "rounds" with plant equipment operators, watched technicians (e.g., instrumentation and control) perform control board instrument checks, observed operator response to annunciators, and conducted an overall assessment of on-shift operator knowledge and shift management command and control. Operational evolutions that were witnessed and procedures reviewed , included the plant shutdown, reactor shutdown, and plant cooldown, as well as routine surveillance activities involving control room logs and daily and shiftly control room rounds. Round-the-clock inspection activities commenced on

April 30 prior to the start of RFO6 and continued until the unit reached cold shutdown (Mode 5) conditions on May 2, 1999.

Subsequently, inspectors conducted sample reviews of ongoing operational evolutions, including verification of controls consistent with the "defense in depth" criteria delineated in operations procedure OP 3260A, "Conduct of Outages", and observation of the activities governed by OP 3216, "Reactor Coolant System Drain", as an infrequently performed test or evolution (IPTE). Procedural controls for the residual heat removal system, the fuel pool cooling and purification system, and the cold over-pressure protection system were also evaluated.

The inspector observed proper three-way communications and reactivity management by the control room staff throughout the downpower evolution. In addition, the inspector witnessed a satisfactory turbine overspeed test conducted in accordance with SP 3623.1, "Turbine Generator Testing," and found the evolution was well coordinated between the control room and the in-plant personnel.

Specific technical questions were raised regarding the use of abnormal operating procedures (e.g., AOP 3554), consistent with the plant operating procedures for "At Power Operation" and "Plant Shutdown". In this regard, the inspector reviewed a licensee letter (B16841), dated January 12, 1998, addressing the modification of the licensing bases for N-1 Loop operation. Additionally, an IPTE OP 3216 procedural prerequisite, involving a pump inoperability verification, was questioned and determined to be adequately controlled by a referenced surveillance procedure, SP 3604A.6, for the operational mode relevant to the verification requirement. General inspection activities included use of the "One-Stop-Shop" as a first time initiative for RFO6 work control, and observation of interdepartmental liaison (e.g., chemistry and health physics support of operations).

c. Conclusions

Operational evolutions in support of Unit 3 RFO6 were generally well controlled, with "defense in depth" considerations and departmental support of operational activities in evidence. Communications and shift turnover controls were adequate; although, as discussed by the inspectors with the responsible shift mangers, not always consistent with the expectations for three way communications and feedback from shift briefings set by the conduct of operations protocol.

O1.2 Loss of Control Room Main Board Annunciators

a. Inspection Scope (71707)

The inspector observed the control room operators' response to a loss of main board annunciators, and assessed the licensee's overall response to the event.

b. Observations and Findings

On May 5, 1999, the inspector was performing control room observations during restoration of DC electrical buses to a normal lineup. The restoration was initiated following a brief for SP3646A.17, "Train A ESF With LOP Test (IPTE)," due to concerns raised about the performance of a surveillance test with an abnormal DC bus alignment. The shift manager made a conservative decision to restore the DC bus to normal, which was coordinated through special procedure (SPROC) EN99-3-13, "DC Bus 5 and 6 Cross-Tie," following the successful replacement of station battery 5.

During the SPROC restoration phase, a momentary loss of main control board annunciators occurred. The inspector observed that the control room operators, under the direction of the Unit Supervisor, entered and performed the applicable actions of relevant abnormal operating procedures, verified the status of critical reactor coolant system parameters and the overall plant, and attempted to recover from the transient. However, a number (approximately 20-30) of individual annunciators had failed to reset following the transient. The significance of a majority of the annunciators was mitigated by the status of their associated systems, i.e., the systems were either out-of-service, or were not needed for the current plant conditions. After the initial voltage drop, the licensee completed the necessary procedure steps and restored the DC bus to the normal electrical alignment. Subsequently, the instrument and control (I&C) department corrected the malfunctioning annunciator problem by deenergizing the panels individually using approved plant procedures.

The inspector observed the event brief shortly after the preliminary cause of the event was identified by the licensee. The brief was well attended and appeared to be thorough in the details of the apparent cause. The inspector determined that the licensee understood the cause of the event and the overall impact on the plant, as evidenced by the licensee's actions in response to the event, as well as the detailed assessment provided during the event brief. The licensee concluded that the unanticipated voltage drop that caused the event was initiated due to the closure of a battery charger output breaker onto the DC bus prior to pre-charging the battery charger capacitors. Procedure changes covering the 125 VDC System were recommended following the condition report investigation of the event, however, due to the specialized one-time nature of the DC bus alignment utilized under the SPROC, the corrective action appears to be adequate.

c. Conclusions

The licensee responded appropriately to the loss of Unit 3 main board annunciators, identified the cause and recovered from event in a timely manner, and appropriately restored the electrical alignment to normal prior to the continuation of testing.

U3 O2 Operational Status of Facilities and Equipment

O2.1 Operational and Configuration Control of Equipment and Systems

a. Inspection Scope (60705, 60710)

The inspector reviewed and assessed the Unit 3 shutdown risk controls, the mode change evaluation process, certain operability determinations, selected condition reports relating to configuration management issues, and Nuclear Oversight actions relating to these programmatic activities.

b. Observations and Findings

On May 18, 1999, Nuclear Oversight (NO) issued a Stop Work Order due to the identification of work control planning problems that could have resulted in "orange" shutdown risk conditions had they not been identified during a review of shutdown risk prior to implementation. In discussions with NO management, the inspector verified that reactor fuel movement was allowed to continue, that restoration of safety-related equipment could continue, and that a multi-disciplinary team of personnel with licensed operations experience had been formed to conduct reviews for the release of future work. On May 24, 1999, the Stop Work Order was lifted, but the multi-disciplinary team continued its work review and release functions.

Subsequently, some configuration control events were either identified by the licensee or self-revealed by small water spills (i.e., an open refueling water storage tank flow path). These events, primarily involving valve positioning or tagging controls, appeared to result from problems with the status control of the valves and other equipment and testing activities. In general, a valve might be authorized to be in the position it was found, but other work would then be performed, without recognizing the existing configuration; thus leading to control problems. In one case, a "red" shutdown risk condition was identified when some containment isolation valves, authorized to be open for planned work, were not tracked as exceptions to the containment integrity status.

While each of the noted configuration control issues was of minor safety significance and immediately corrected, the aggregate impact of these examples appeared to be of some programmatic concern. The inspector discussed this concern with plant and operations management, who then performed a common cause analysis of the noted events for the purpose of identifying the need for appropriate corrective measures. The results of the licensee's common cause review provided focus on management involvement in work control restoration activities, including attention to the workload, work practices, and processes. Licensee corrective actions included a process change requiring a full system valve line-up inside a tagging boundary prior to restoration, a second check of all restoration sequences involving filling and venting, and more rigorous use of drawing, procedural, and tagging clearance during pre-job briefs and certain evolutions.

The inspector reviewed these corrective actions with the Operations Manager and cognizant NO personnel prior to the plant being heated to hot shutdown (Mode 4) conditions. These process improvements establish tighter controls, with a track record for having worked more effectively at Millstone Unit 2. Along with the increased management focus in the area of configuration control expectations, additional briefings of the operations and field personnel were being conducted to reinforce these new expectations.

The inspector attended mode change readiness meetings, reviewed significant condition reports (e.g., CR M3-99-2162; documenting the loss of a vital 120 v-ac power bus for a short period of time) and the corrective actions taken in response, and evaluated several operability determinations (e.g., OD MP3-020-99; documenting missing internals to two check valves in the "B" emergency diesel generator fuel oil return lines) for evidence of proper design input and plant operations review committee (PORC) review and authorization. The inspector also observed a number of PORC meetings, particularly noting in one case a conservative approach to shutdown risk in the licensee's decision to delay work in the electrical switchyard until the reactor vessel reassembly following refueling reached the state of supporting pressurization for core cooling considerations.

c. Conclusions

A number of problems in Unit 3 configuration and work control were identified by either Nuclear Oversight or the line organizations or were self-revealing during this inspection period. Licensee management addressed these concerns with more rigorous process controls, along with a stronger management focus on these issues. Inspector follow-up of licensee and NO corrective measures, as well as the actions taken to address the technical problems documented in several CRs and ODs appeared to apply appropriate focus on the identified concerns.

U3 O8 Miscellaneous Operations Issues

08.1 (Closed) URI 50-423/97-83-08: RHR Heat Exchanger Leak Rate

a. Inspection Scope (92901)

The inspector reviewed the licensee's technical evaluation regarding the potential residual heat removal system leakage, relative to the post-accident equipment leakage addressed in technical specifications.

b. Observations and Findings

Unresolved Item (URI) 50-423/97-83-08 was initiated and documented in NRC Inspection Report (IR) 50-423/97-83, following the Unit 3 Operational Safety Team Inspection conducted in April 1998. The URI detailed the licensee's failure to fully address potential post-accident equipment leakage due to known leakage from residual heat removal (RHR) system components. In addition, the overall radiation dose and other effects from this leakage were not addressed relative to the requirements of Technical Specification (TS) 6.8.4.a, "Primary Coolant Sources Outside Containment." NRC IR 50-423/99-02 documented the licensee's actions in response to the URI, however, the issue of potential RHR post-accident leakage was also not adequately addressed by the licensee.

As a result, the licensee performed a technical evaluation in April 1999, to define the post-LOCA (Loss-of-Coolant-Accident) conditions for monitoring the RHR system equipment leakage as required by TS 6.8.4.a. In addition, the evaluation was performed to verify that any "known" leakage exhibited by the RHR system components was within the post-LOCA equipment leakage requirements as specified in the Final Safety Analysis Report (FSAR).

The inspector reviewed the technical evaluation and determined the licensee adequately addressed the RHR system components leakage since the leakage: (1) is bounded by design basis values in the FSAR relative to the post-LOCA equipment leakage; (2) has been analyzed relative to pressure and temperature conditions similar to post-LOCA conditions; and (3) has been addressed relative to the leakage monitoring program through: (i) a design calculation, P(R)746, "ECCS System Leakage Outside Containment;" (ii) specific inspections that have been completed, as well as additional inspections that are planned in the interim, until the licensee incorporates the appropriate inspections of the RHR system into the surveillance procedure which implements the leakage program required by TS 6.8.4.a, namely, SP3612B.5, "Primary Leakage Outside Containment."

c. Conclusions

The inspector concluded that the licensee has adequately addressed the potential residual heat removal system leakage, and there was no violation of NRC requirements. Therefore, **URI 50-423/97-83-08** is considered **closed**.

U3.II Maintenance

U3 M1 Conduct of Maintenance

M1.1 Observation of Surveillance Testing Activities

a. Inspection Scope (61726)

The inspector witnessed portions of various surveillance activities, conducted either in the control room or at the field locations of the components being tested. Procedures were reviewed and procedural controls were evaluated. The inspector monitored test results, reviewing a sample of the surveillance test records, with observations for the various testing activities documented below.

b. Observations and Findings

The inspector observed portions of surveillance procedure SP 3712G, "Main Steam Code Safety Valve Surveillance Testing." The inspector verified that the power range nuclear instrumentation trip setpoints were adjusted prior to valve testing and that the valve test frequency was in accordance with technical specification requirements. The pre-job brief was determined to be detailed; test termination criteria, expected plant indications and alarms, and personnel responsibilities were clearly communicated. Good procedure adherence and attention to detail were noted during the surveillance. Both the management test lead and test engineer monitored the surveillance activity. All five relief valves tested ("As Found") were determined to be within the +/- three percent tolerance band, in compliance with Technical specification (TS) 4.7.1.1 and the ASME Boiler and Pressure Vessel Code, Section XI, Article IWV-3510. The automated work order (AWO M3 98 12930) documentation and main steam code safety surveillance testing data sheets were reviewed for test results in line with the acceptance criteria. No discrepancies were noted.

The inspector also witnessed the conduct of testing activities, as controlled by the following surveillance procedures:

- SP 3604A.6, "Charging/SI Pump Inoperability Verification"
- SP 3610A.4, "Leakage Determination for Low Pressure Safety Injection System Valves"
- SP 3608.6, "Safety Injection System Valve Operability Test"

Shift pre-job briefings were observed and licensed operator communications and interactions with the test leads and system engineering personnel were noted. During the performance of a SP 3610A.4 leakage test on a low pressure safety injection (SIL) check valve, the operators suspended the test sequence to evaluate the open position of a SIL injection valve, 3SIL*MV8809A. Discussion with the cognizant test engineer resulted in continuation of the test without the need for closing the SIL valve. A subsequent review of SP 3610A.2, "Residual Heat Removal Pump 3RHS*P1B Operational Readiness Test", by the inspector identified that the same check valve test was performed with injection valve 3SIL*MV8809A closed. This apparent inconsistency was discussed with the shift manager and it was determined that the two different surveillance tests had separate objectives. The conduct of SP 3610A.4 constituted a leakage test to fulfill the requirements of TS 6.8.4.a.2, while SP 3610A.2 was intended to establish residual heat removal train operability in accordance with TS 4.4.1.4.2.1. The inspector had no further questions regarding performance of the leak testing.

With regard to the conduct of the SP 3608.6 valve operability testing, problems with a replacement orifice resulted in the need to repeat the test. While the objective of the testing was to verify check valve full stroke capability in accordance with TS 4.0.5 requirements, some of the data collected during the repeat test appeared to indicate a small flow imbalance between two safety injection, hot leg flow paths. The inspector reviewed the Technical Evaluation, M3-EV-99-0065, which concluded that the flow rates through each path met the required acceptance criteria. Discussion with system engineers indicated that Westinghouse Electric Company (W), as the nuclear steam system supplier, would be consulted to provide advice on the measured flow imbalance. Subsequently, the inspector reviewed a W letter, NEU-99-088, documenting the acceptability of observed hot leg flow imbalance. Minimum flow requirements were met, considering both the flow difference and the system resistance for pump run-out protection. The inspector discussed this analysis, the final test configuration, and the surveillance results with the responsible system engineer and had no additional questions.

c. Conclusions

Unit 3 Surveillance testing was conducted in accordance with established procedures. Good coordination was observed between control room operators and the responsible engineering personnel in support of the testing activities, system lineups, and disposition of test results. Where appropriate, technical expertise was obtained to confirm that the surveillance test data was consistent with the acceptance criteria.

M1.2 Emergency Diesel Generator Testing

a. Inspection Scope (61726)

The inspectors observed the "A" Emergency Diesel Generator (EDG) surveillance testing performed on May 5-6, 1999.

b. Observations and Findings

On May 5, 1999, the inspectors witnessed the pre-job brief in preparation for SP3646A.17, "Train A ESF With LOP Test (IPTE)." The brief was comprehensive, in that it covered all the expected elements, e.g., termination criteria, contingency actions, and lessons learned from previous tests. In addition, participants exhibited a good questioning attitude regarding an off-normal DC bus alignment. While the alignment would not have had an effect on the scheduled test, the Shift Manager made a conservative decision to return the DC bus alignment to normal prior to commencement of the test.

In the interim, a few issues arose that delayed the licensee's performance of the surveillance. First, both the "A" and "B" emergency diesel generators (EDGs) were declared inoperable due to the licensee's identification that they had failed to perform a technical specification (TS) surveillance requirement. As a result, the licensee issued Licensee Event Report 50-423/99-003-00, which will be inspected by the NRC at a later date. Second, during the realignment of DC buses that was discussed above, the control room received a momentary loss of annunciators. This event is detailed in Section O1.2. Third, during the licensee's restoration from the loss of main board annunciators event, the "A" EDG developed a fuel leak after approximately 30 hours of operation of a TS required 24-hour endurance run. The licensee conducted the appropriate repairs and retests, and the EDG was made available for the LOP/ESF test.

On May 6, 1999, the licensee had restored the DC bus alignment to normal, recovered from the EDG fuel leak, and made applicable procedure changes to SP 3646A.17 to continue with the ESF/LOP test. The licensee also performed an additional pre-job brief due to different control room shift staffing, as well as additional people in the test group.

Prior to the ESF/LOP test, the licensee performed simulated practice runs with specific members of the test group, for the purpose of establishing the timing for performance of the time-critical sequences that exist in the opening steps of the surveillance test. The inspector observed that this "practice run" appeared to benefit the test group in that the time-critical steps were completed as required without incident. The inspector also observed expected equipment responses during the test. In addition, communications between test personnel in the control room and personnel in the field was appropriate and in accordance with licensee procedures. Following the test, deficiencies and areas for improvement were documented in a condition report for inclusion in the corrective action program.

c. Conclusions

The inspector concluded while problems arose during the test, the licensee's performance of the "A" emergency diesel generator testing was good.

M1.3 Refueling and In-Mast Fuel Sipping Activities

a. Inspection Scope (60710)

The inspector observed the transfer of several fuel assemblies between the reactor vessel and the spent fuel pool storage racks during fuel offload and reload evolutions. Additionally, the inspector reviewed applicable documentation and interviewed personnel involved with these activities.

b. Observations and Findings

The inspector observed good control of the evolution and proper handling of the fuel assemblies in accordance with procedural requirements. Clear communications were maintained between the control room, the refueling bridge, and the spent fuel pool, which helped to establish positive controls over the fuel movements. Proper oversight, foreign material exclusion controls, and personnel radiological protection controls were observed. All personnel interviewed were knowledgeable regarding the fuel handling requirements and their responsibilities. Refueling cavity water clarity was acceptable, and personnel on the refueling bridge promptly stopped fuel movement in response to fuel handling equipment problems in the spent fuel pool building and on the refuel bridge.

The inspector observed vendor personnel perform in-mast fuel sipping during the fuel movements in an attempt to identify a suspected leaking fuel bundle. The fuel sipping activities utilized specialized equipment designed to measure the radiological concentration of a forced air stream that was injected external to the lower portion of the fuel assembly during the fuel movements. The inspector noted that personnel involved with this activity had a good understanding of the fuel sipping requirements and did not identify any deficiencies.

c. Conclusions

The licensee and vendor personnel performed fuel handling and fuel sipping activities well. Personnel were observed tc be attentive and properly suspended the fuel handling activities in response to refuel bridge and transfer canal equipment problems.

U3 M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Inservice Inspection (ISI)

a. Inspection Scope (73753)

The inspector reviewed plans and schedules for the current ISI interval (sixth outage, first period, second interval) to verify compliance with the requirements of ASME Section XI, 1989 edition, and 10 CFR 50.55a(g). Areas inspected included ASME Section XI ISI program coverage, qualifications and certifications of the nondestructive examination (NDE) personnel, NDE procedures, results of NDE, and oversight of NDE contractors. In addition, the inspector observed selected NDE activities, including ultrasonic (UT) and liquid penetrant (PT) examination of a pipe to elbow weld on the Safety Injection System. The inspector also observed the in progress eddy current testing of steam generator tubes in three generators.

b. Observations and Findings

Northeast Utilities has nondestructive examination (NDE) contractors perform ISI examinations and provides oversight and monitoring of selected tests. The NDE procedures being used were reviewed and approved by a NU level III examiner, quality assurance and the authorized nuclear inservice inspector and were in accordance with the ASME Code requirements. The inspector reviewed some ultrasonic, penetrant, magnetic particle and eddy current test procedures used by NDE personnel and found them to be adequate for the NDE tasks performed. NDE contractor personnel were trained and qualified in the use of NU test procedures. As part of the oversight function, NU performs a review and approval of personnel qualifications, monitoring of activities and a review and acceptance of test results. The review and acceptance of NDE test results is performed by a NU Level III examiner. The inspector verified that licensee and contractor NDE personnel were qualified in accordance with the requirements of the ASME Code. The inspector found the inspection implementation consistent with the approved procedures. The inspector evaluated oversight of contractor NDE activities by review of the oversight reports, surveillance reports, field observation checklists and summary logs which documented appropriate NU involvement in verification of NDE contractor activities.

Examination data and documentation were reviewed and found to be in accordance with the NDE procedures and ASME Code requirements. NDE personnel performing inspections had properly identified and recorded indications. The data reports generated as a result of these inspections were reviewed for Code compliance by NU level III personnel and dispositioned for resolution or acceptance.

c. Conclusions

Unit 3 inservice inspection was performed acceptably and included appropriate ASME program coverage, qualified personnel, approved procedures, proper implementation, acceptable examination documentation, and NU oversight. The inspections performed were thorough and of sufficient extent to determine the integrity of the components inspected.

M2.2 Eddy Current Testing of Steam Generator Tubes

a. Inspection Scope (73753)

The ET of one hundred percent of the tubes in steam generators A and C was performed during this outage. Also, selected tubes in the D generator were to be examined to evaluate the status of indications identified during the previous outage. Areas selected for inspection included NDE procedures. equipment calibration, qualifications and certifications of NDE personnel, acceptance criteria and documentation and evaluation of acquired data. Inspection of these attributes was for compliance with the requirements of the ASME Code Section XI, 1989 edition and applicable industry standards.

b. Observations and Findings

The personnel, procedures and equipment used for this testing were supplied by a contractor with NU providing management and technical oversight. Steam generator tube inspections were performed to the requirements of the ASME Code and industry examination guidelines. These requirements are detailed in the site specific ET data analysis guidelines manual. The guidelines require that degradation detection and flaw sizing be accomplished using techniques and personnel qualified for this site. The inspector reviewed the inspection procedure and portions of the guideline manual. Also, the inspector reviewed the training records for personnel trained in the application of the process, interviewed applications and analysis personnel and evaluated NU oversight of the process. The inspector also examined the tools and equipment used to capture and preserve the tube condition data.

The inspector reviewed portions of the procedures used for the eddy current testing of steam generators A, C and D. Tube inspection was not performed on steam generator B during this outage since a one hundred percent inspection was performed during the previous outage. The steam generators are of the "A" bend design and tubed with thermally treated Inconel 600. Each generator contains a total of 5626 tubes. One hundred percent of the tubes in the A and C generators were inspected for their full length using the bobbin coil. Fifty percent of the tubes in the A and C generator were examined in the hot leg using the "plus point" (rotating coil) probe. Selected tubes in the D generator were examined to assess the progress of tube degradation in specific locations identified during refueling outage five, (May 1995). No change was detected in tube condition when compared to the results found in the previous outage.

The procedures issued to control this special process presented a good description of the process, clearly stated the objectives and provided instructions to assure accurate data accumulation and analysis in a consistent manner. Provision was made in the procedure to resolve discrepancies between the primary and secondary analysts. This activity was performed by the resolution analyst on site. There were adequate provisions in the procedures to guide the analysts in the performance of the evaluation process with precautions and prerequisites spelled out to assure the most appropriate data analysis practices are used. Documentation and tracking mechanisms were in place to capture and transmit the data to primary and secondary analyst locations. Also, provisions were incorporated in the data acquisition process to provide, for future comparison, a permanent historical record of the as found data for each individual tube.

Training requirements were established with emphasis on equipment installation using the site steam generator mock up. The inspector observed the replication of the steam generator lower head used to train craft personnel in the methods for installation of the robotic test equipment. The training emphasis was on accurate positioning of the equipment while minimizing personnel exposure. The inspector concluded that training of personnel by installation of actual test equipment in the lower head mock up was of significant value in assuring accurate tube identification and reliable test results.

The inspector observed the application of the inspection process in two generators (A and C) and found the work to be well planned, coordinated and executed. The inspector verified that data acquisition equipment exhibited current calibration stickers. Oversight of the work was good with an appropriate emphasis on accuracy of data analysis by both primary and secondary analysts and resolution personnel. The inspector noted that the NU oversight level III examiner was adequately involved in the data analysis evaluation.

c. Conclusions

Eddy current testing of Unit 3 steam generator tubes observed included acceptable procedures, qualified personnel, proper implementation, appropriate examination documentation and adequate NU oversight. The inspections performed were thorough and of sufficient extent to determine the integrity of the tubes inspected. When identified, nonconforming conditions were verified by use of alternate probe types, characterized, sized and properly dispositioned in accordance with established requirements.

M2.3 Steam Generator Tube Plugging Results

The inspector reviewed a special report (B17791) submitted by the licensee to the USNRC Document Control Desk on June 2, 1999, pursuant to the Unit 3 technical Specifications 4.4.5.5.1 and 6.9.2. This report documented the results of steam generator eddy current inspections completed on May 17, 1999, reflecting the condition of the steam generator tubes at the end of Cycle 6 operation. A total of 11,274 tubes were inspected utilizing bobbin coil probes, while an augmented sample of 6,150 tubes was inspected utilizing rotating pancake probes.

Eight tubes were plugged based upon the identification of flaws exceeding the criterion for wall thickness depth and an additional six tubes were plugged by the licensee on a discretionary basis. To date, of the 22,504 total tubes in all four steam generators, 55 tubes have ben removed from service by plugging.

U3 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) LER 50-423/98-10: Failure to Meet Technical Specification (TS) Definition of Analog Channel Operational Test of the Unit 1 Main Stack Noble Gas Activity Monitor

This LER documented that the method used to test the Unit 1 main stack noble gas monitor was not in full compliance with the Unit 3 TS definition. The monitor was subsequently retested and found to be operable. This condition was found as part of a TS surveillance compliance review.

The inspector conducted an on-site review of the LER and reviewed Unit 1 procedure 406JJ and verified that it had been changed to reflect the Unit 3 testing requirements. The failure to properly test the Unit 1 main stack noble gas monitor is a violation of Unit 3 TS Table 4.3-9. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (**NCV 50-423/99-06-03**). This violation is in the licensee's corrective action program as CR M3-98-0784. This LER is **closed**.

M8.2 (Closed) LER 50-423/98-17: Testing of Low Pressure Safety Injection Check Valve 3SIL*V15 Contrary to TS 4.0.5 Requirements

This LER documented that testing of valve 3SIL*V15 was not in accordance with TS 4.0.5. Generic Letter 89-04, "Guidance On Developing Acceptable Inservice Testing Programs," allows testing one valve in an identical valve group on a rotating basis. Valve 3SIL*V15 was tested during the Cycle 1 refueling outage and was scheduled to be tested during the Cycle 5 refueling outage. The licensee made a sequence change to defer valve testing that was not in accordance with GL89-04 guidelines.

The inspector conducted an on-site review of the LER and verified that a relief request was submitted and approved by the NRC, and that the subject valve is scheduled to be tested during the Cycle 6 refueling outage. The failure to test low pressure safety injection check valve 3SIL*V15 in accordance with TS 4.0.5 is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy (**NCV 50-423/99-06-04**). This violation is in the licensee's corrective action program as CR M3-98-1156. This LER is **closed**.

M8.3 (Closed) LER 50-423/98-25: Failure to Perform Technical Specification Required Full Loop Channel Calibration of Meteorological Monitoring Instrumentation

This LER documented that the meteorological monitoring wind speed channel instrumentation was not properly being calibrated. This issue was licensee identified as follow up to a similar issue identified by the NRC at Unit 2; reference NRC Inspection Report 50-336/98-207-17.

The inspector conducted an on-site review of the LER and reviewed the licensee's corrective actions and determined that they were appropriate. The failure to properly calibrate the meteorological monitoring wind speed channel is a violation of TS 4.3.3.4. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-423/99-06-05)**. This violation is in the licensee's corrective action program as CR M3-98-2195. This LER is **closed**.

M8.4 (Closed) LER 50-423/98-28: Failure to Perform Increased Frequency Testing of RHS*MV8702B

This LER documented that valve 3RHS*MV8702B test frequency was not adjusted in accordance with ASME Section XI requirements. Licensee review of historical data revealed that valve 3RHS*MV8702B entered the alert range in December 1989 during the Cycle 1 refueling outage and therefore required an increased test frequency in accordance with technical specifications. The valve was not tested again until the Cycle 3 refueling outage.

The inspector conducted an on-site review of the LER and reviewed the licensee's corrective actions and determined that they were appropriate. The failure to properly test valve 3RHS*MV8702B is a violation of TS 4.4.6.2.2.e. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-423/99-06-06)**. This violation is in the licensee's corrective action program as CR M3-98-2438. This LER is **closed**.

M8.5 (Closed) LER 50-423/98-31: Incomplete Testing of the P-4 Interlock Function

This LER documented that the P-4 interlock functional test did not verify the functionality of the reactor trip breaker and bypass breaker 52b contacts and associated cell switch contacts for an at power breaker alignment. The surveillance procedure was subsequently revised and the P-4 logic properly tested satisfactorily.

The inspector conducted an on-site review of the LER and determined the licensee's corrective actions were appropriate. The failure to properly test the P-4 logic is a violation of TS 3.2.2. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-423/99-06-07)**. This violation is in the licensee's corrective action program as CR M3-98-2617. This LER is **closed**.

U3.III Engineering

U3 E1 Conduct of Engineering

E1.1 Follow-up of RFO6 Engineering Activities

a. Inspection Scope (37551, 60710)

The inspector reviewed the design change package for the Fuel Cycle 7 core reload, as well as other design change notices, engineering evaluations and condition report engineering dispositions relating to modifications performed during the outage. As appropriate, the inspector examined the field work associated with various design changes.

b. Observations and Findings

The inspector reviewed design change record (DCR M3-99-013) documenting the Cycle 7 core design, which was supported by a Cycle 7 Reload safety evaluation prepared by Westinghouse and a licensee Integrated Safety Evaluation. The inspector confirmed that the core reload analysis and plant specific safety assessment address the top nozzle hold-down spring screw failures identified at the VC Summer plant, and being evaluated by Westinghouse as a potential Part 21 issue. Inspections for this problem were conducted during the Cycle 6 core offload; and although one fuel assembly was found to have fractured spring screws, the subsequent licensee evaluation concluded that all the fuel assemblies to be used in Cycle 7 have intact spring screws and are acceptable for use.

DCR M3-99-013 also addresses an issue involving the protective bottom grid sizing for the new Cycle 7 fuel. With the introduction of the new "P-Grid" feature on fuel assemblies in a certain region of the reactor core, the smallest linear dimension in the flow path is smaller than fine mesh screen opening on the containment recirculation sump. This raises a question regarding literal compliance with USNRC Regulatory Guide (RG) 1.82 (Revision 2), position C1.11. The licensee DCR, supported by a Westinghouse analysis, concludes that the intent of the Regulatory Guide is met because long-term core cooling and containment heat removal functions are not adversely affected by the new design. This position is, in part, supported by the RG 1.82 statement that "the minimum restriction should take into account the requirements of the systems served." The inspector discussed this issue with personnel in the NRC Office of Nuclear Reactor Regulation (NRR) and determined that this design feature is not unique to Millstone Unit 3. Based upon the site-specific analysis documented by both Westinghouse and the licensee for the new "P-Grid" design feature, the inspector has no additional technical or regulatory questions regarding this issue at this time.

During the RFO6 full core offload, in-mast sipping was utilized to determine whether any fuel assemblies contained one or more leaking fuel rods. Based upon reactor coolant system activity levels during cycle 6 operation, it was expected that a small fuel leaker was in evidence, but with such low activity as to not allow specific identification during normal operation. The sipping technique identified fuel assembly D79 as the suspected leaker. This standard Westinghouse fuel assembly was placed into service during Cycle 2 operation. The inspector reviewed a licensee memorandum summarizing the history, use, and potential failure scenario for assembly D79; and has no further questions on this issue, as it was not planned for reload into the core for Cycle 7 operation.

In addition to the fuel cycle management and design issues discussed above, the inspector reviewed the following modification activities and engineering questions that arose during RFO6:

- Design Change Notice, DCN DM3-00-0236-99, for replacement of valve 3RCS*V132, which had a known stem disk separation and had been in operation with a Temporary Modification installed

- DCN DM3-03-0631-97, for replacement of some "A" feedwater loop piping due to erosion/corrosion concerns, with supporting Engineering Evaluation, M3-EV-970213

- Condition Report Engineering Disposition for CR M3-99-2174, supported by Calculation No. 99-SDS-01720-M3, that evaluates flaws in the longitudinal seam welds of certain service water system piping spool pieces

The inspector reviewed the completed work and evaluation packages associated with the above engineering activities. Material, welding, non-destructive examination, and testing criteria were evaluated against the appropriate Code provisions. The results of some of the engineering analysis were discussed with the cognizant licensee design staff. Field work and design drawings were spot-checked, as appropriate, to evaluate whether the plant configuration was consistent with the design assumptions and input. The inspector verified the existence of construction and testing records demonstrating compliance with the design and code requirements.

c. Conclusions

A sample of design modification, engineering evaluation, and fuel cycle analysis issues were reviewed for implementation during RFO6. The design change records, supporting calculations and analyses, as well as observed field conditions were found to be consistent with governing Code requirements. Interviews with licensee engineering managers and technical personnel, augmented by inspector discussions with NRC Office of NRR and Region I technical specialists, confirmed that acceptable design practices had been used in the disposition of the above technical/design issues.

U3 E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-423/98-03: Missed In-Service Inspection (ISI) Pressure Tests for Class 2 and 3 Systems

This LER documented that the licensee failed to perform required ISI pressure tests for 2 ASME systems and 17 containment isolation valves during the current ten year inspection interval. Several components were not included in the ISI program but were listed in the FSAR. These components had been tested as part of the Appendix J program with acceptable results. This issue was discovered during the licensee's review of the ISI pressure test program.

The inspector conducted an on-site review of the LER and reviewed the licensee's corrective actions and determined that they were appropriate. The inspector verified that the licensee plans to test the components during the Cycle 6 refueling outage. The failure to perform ISI pressure tests for various Class 2 and 3 systems is a violation of technical specification (TS) 4.0.5. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-423/99-06-08)**. This violation is in the licensee's corrective action program as CR M3-98-0299. This LER is **closed**.

E8.2 (Closed) LER 50-423/98-05: ASME Section XI Code Requirements Not Met

This LER documented several instances where additional and/or successive examinations of pipe supports and/or welds were not performed, as required by Section XI of the ASME Boiler and Pressure Vessel Code, in 10 separate ASME systems. The deficiencies resulted from activities performed during the Cycle 2 and Cycle 5 refueling outages. The examinations have since been performed and found to be acceptable.

The inspector conducted an on-site review of the LER and reviewed the licensee's corrective actions and determined that they were appropriate. The failure to perform the required ASME Section XI examinations is a violation of TS 4.0.5. This Severity Level IV violation is being treated as a Non-cited Violation consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-423/99-06-09)**. This violation is in the licensee's corrective action program as CR M3-98-0223. This LER is **closed**.

IV Plant Support
(Common to Unit 2 and Unit 3)

R1 Radiological Protection and Chemistry Controls

R1.1 Radiological Protection and Chemistry (RP&C) Controls

a. Inspection Scope (83750)

A review of the radiation protection program at Unit 3 was conducted during refueling outage conditions. Areas of inspection focus were based on high exposure outage activities and included in field observation of:

Eddy current inspection of steam generators A and C
Initial primary man-way opening of C steam generator
Control rod drive mechanism unlatching
Reactor upper internals removal
ALARA pre-shield walkdowns and post-shield evaluations for the pressurizer surge line, Reactor coolant system (RCS) check valves V-37 & V-71, RCS isolation valve 132

Other areas reviewed included:

Plant tours of containment, auxiliary building and engineered safety features building
Unit 3 containment surveys, radiation work permit controls, and alarming dosimeter use
Unit 3 air sample results and investigative whole body count results
Radiological Condition Reports (27) reported between March 26 and May 11, 1999
Unit 3 refueling outage ALARA exposure estimate and tracking system
In-office review of Unit 2 air sample results

b. Observations and Findings

During February 1, 1999, an air sample was taken in the Unit 2 reactor cavity. Preliminary gross alpha measurements indicated radioactivity levels above airborne radioactivity posting requirements. The cavity area was not posted and the air sample was saved and recounted 24 hours later to determine whether naturally occurring radon gas was the cause, which was confirmed. Since no airborne radioactivity area was actually present, there was no violation of 10CFR20 requirements. The licensee's review of the incident indicated that the initial decision to not post the area was not a conservative decision and that additional radiological engineering support could have been utilized in making a more informed and timely decision. Appropriate procedure and training corrective actions were entered into the corrective action program to improve program response in the future.

While in the Unit 3 containment, the inspector observed a worker's electronic pocket dosimeter (EPD) in the alarm condition. While wearing the required hearing protection, the inspector could not hear the alarm more than two feet away from the worker while in a normal noise environment. While accompanying the Unit 3 ALARA Coordinator to a high radiation area pre-shield location, as directed by the RP technician, the inspector's EPD alarmed intermittently, temporarily exceeding the dose rate alarm. The inspector could barely hear the EPD alarm while wearing the required hearing protection in a low noise environment (all of containment was designated a hearing protection required zone). Subsequent follow-up revealed the following:

Condition Reports (CRs) M3-99-1390 and M3-99-1525 dated 5/5/99 and 5/10/99, respectively, documented two incidents where a worker made a high radiation area containment entry utilizing an alarming EPD and did not hear the integrated dose alarm which resulted in exceeding the intended entry dose by 18 and 16 mrem, respectively. The radiation work permits specify EPDs as the high radiation area entry control. Technical Specification 6.12.1.b states that entries into high radiation areas require, "A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received." The workers were wearing the required alarming EPDs, however, because they were not audible, they did not provide an effective alarm function to assure adequate and reasonable control of personnel exposure in the High Radiation Area, as required by TS 6.12.1.b. These two incidents represent two examples of a violation of TS 6.12.1.

The licensee identified the incidents, and on May 11, 1999, obtained the vendor services of a teledosimetry system to allow RP technician remote monitoring of personnel during high radiation area entries. The licensee long-term plan involves investigating other instrumentation options to effect improved EPD alarm audibility in high noise conditions.

c. Conclusions

Two condition reports were written during the Unit 3 refueling outage that documented violations of Technical Specification 6.12.1 high radiation area entry requirements. Both instances involved the use of alarming dosimeters that alarmed after reaching the preset integrated dose value, but were not audible to the worker and resulted in additional exposure to personnel. Both instances were identified by the licensee. Effective short term corrective actions were taken, and long term actions were initiated to evaluate other instrumentation options. This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-423/99-06-10)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into the corrective action program. This violation is in the licensee's corrective action program as Condition Reports M3-99-1390 and M3-99-1525.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection. The licensee acknowledged the findings presented.

INSPECTION PROCEDURES USED

IP 37551	Onsite Engineering
IP 60705	Preparation for Refueling
IP 60710	Refueling Activities
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71715	Sustained Control Room and Plant Observation
IP 73753	Inservice Inspection
IP 83750	Occupational Exposure
IP 92700	Onsite follow-up of Written reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Followup - Plant Operations
IP 92903	Follow-up Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-336/99-06-01	NCV	Failure to Establish Adequate Procedural Guidance for Intentionally Bypassing the Automatic Actuation of ESAS
50-336/99-06-02	NCV	Failure to Perform Design Reviews of Temporary Modifications Installed Through Plant Procedures
50-423/99-06-03	NCV	Failure to Meet Technical Specification (TS) Definition of Analog Channel Operational Test of the Unit 1 Main Stack Noble Gas Activity Monitor
50-423/99-06-04	NCV	Testing of Low Pressure Safety Injection Check Valve 3SIL*V15 Contrary to TS 4.0.5 Requirements
50-423/99-06-05	NCV	Failure to Perform Technical Specification Required Full Loop Channel Calibration of Meteorological Monitoring Instrumentation
50-423/99-06-06	NCV	Failure to Perform Increased Frequency Testing of RHS*MV8702B
50-423/99-06-07	NCV	Incomplete Testing of the P-4 Interlock Function
50-423/99-06-08	NCV	Missed In-Service Inspection (ISI) Pressure Tests for Class 2 and 3 Systems
50-423/99-06-09	NCV	ASME Section XI Code Requirements Not Met
50-423/99-06-10	NCV	Violations of Technical Specification 6.12.1 High Radiation Area Entry Requirements

Closed

The Non-Cited Violations (NCVs) listed above are closed.

50-336/96-06-07	URI	Refueling Pool Drain Line Seismic Issues
50-336/96-09-09	URI	Override of Safety Injection Actuation Signal
50-336/98-208-02	URI	Procedurally Implemented Temporary Modifications
50-423/97-83-08	URI	RHR Heat Exchanger Leak Rate

The following LERs were also closed during this inspection:

LER 50-336/99-09	Manual Reactor Trip due to Steam Leak in Turbine Building
LER 50-423/98-03	Missed In-Service Inspection (ISI) Pressure Tests for Class 2 and 3 Systems
LER 50-423/98-05	ASME Section XI Code Requirements Not Met
LER 50-423/98-10	Failure to Meet Technical Specification (TS) Definition of Analog Channel Operational Test of the Unit 1 Main Stack Noble Gas Activity Monitor
LER 50-423/98-17	Testing of Low Pressure Safety Injection Check Valve 3SIL*V15 Contrary to TS 4.0.5 Requirements
LER 50-423/98-25	Failure to Perform Technical Specification Required Full Loop Channel Calibration of Meteorological Monitoring Instrumentation
LER 50-423/98-28	Failure to Perform Increased Frequency Testing of RHS*MV8702B
LER 50-423/98-31	Incomplete Testing of the P-4 Interlock Function

ATTACHMENT

Millstone Unit 3's Refueling Outage Number 6

Presentation To Region 1

Nuclear Regulatory Commission

April 20, 1999

Agenda

- Overview - Mike Brothers
- Introduction - Chris Schwarz
- Outage Details - Steve Brinkman
  - Overview
  - Schedule
  - Projects
  - Previous Outage Comparisons
  - Status of Operator Burdens
- Benchmarking Initiatives - Chris Schwarz
- Nuclear Oversight - Neil Bergh
- Summary -Chris Schwarz

RFO6 Mission

To safely and competitively complete RFO6 with teamwork, enthusiasm and continuous improvement.

Unit 3 RFO6 Goals

- LTAs/OSHA recordables	0
- Personnel events	0
- Radiation exposure	<170 rem
- Outage duration	<45 days
- Scope growth	<10%
- Expenditures	Within Budget
- Number of Outage Objectives Met	All

Additional Outage Goals

- No loss or interruption of residual heat removal cooling or spent fuel cooling
- No fuel handling-related damaged fuel assembly or insert that would prevent fuel assembly reuse
- No mispositioning of fuel assembly or insert in the reactor core or spent fuel pool
- Maintain Defense in Depth, No unplanned Orange Path entries

Outage Objectives

Rework	< 2%
Continuous run without related shutdown	> 90 days
Critical path schedule adherance	>95%
Configuration control errors	0
Schedule outage modifications completed	100%
Repair of scheduled main control board deficiencies	100%
Removal of scheduled outage temp modifications	100%
Resolution of scheduled operator work arounds	100%
Missed outage PMs/surveillances	0

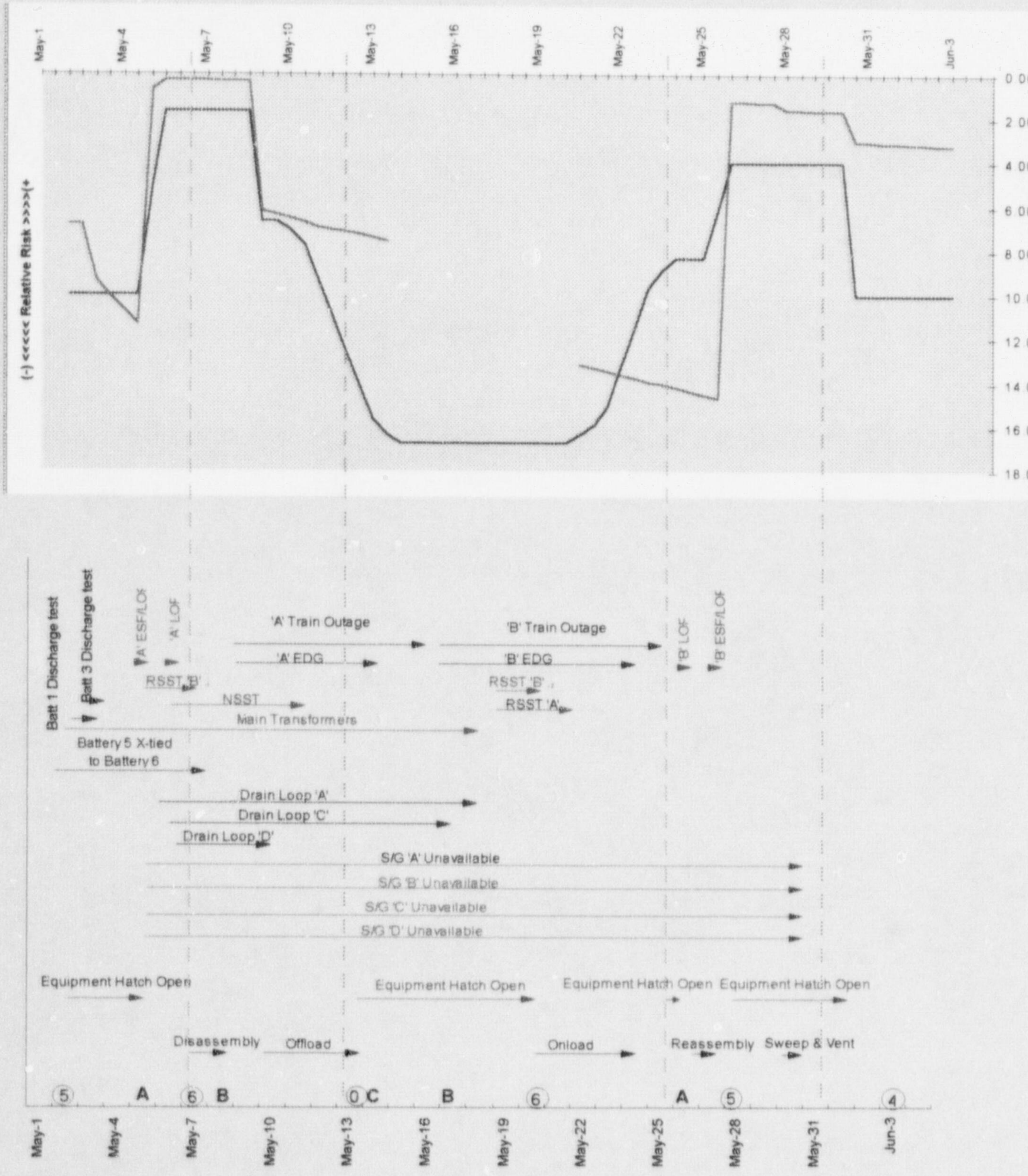
Shutdown Risk Assessment

- Nuclear and personal safety is our Number 1 priority
- Defense in depth
- Risk Profile
  - Drain for disassembly and assembly
- Continuously review throughout outage

RFO6 Shutdown Safety Assessment

(based on schedule issued April 12, 1999)

A - Drain for Disassembly and Assembly
B - Flood to 50 ft.
C - Midloop
○ - Mode



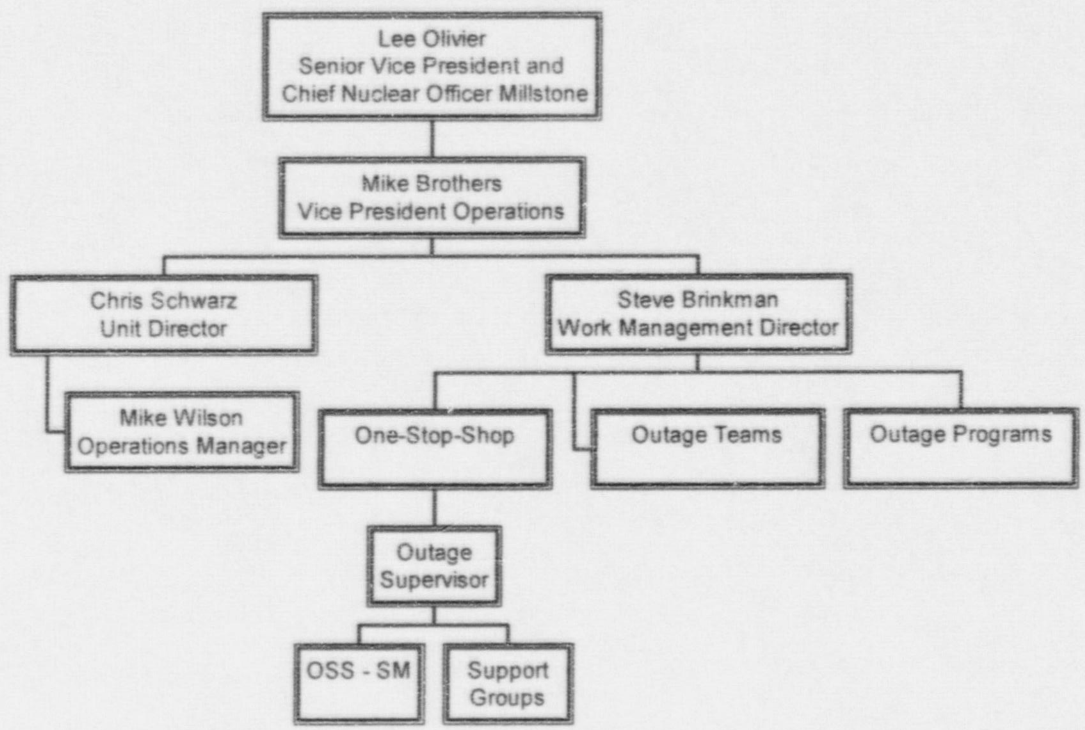
Northeast Utilities Nuclear Safety Standards and Expectations

- Effective control of plant conditions/parameters
- Respect for the core and spent fuel
- Prevent events that could compromise nuclear safety
- Conservative decision making
- Everyone realize how they could impact reactivity management

Maintain Environmental Focus

- Increased focus for RFO6 due to increased staff and work activities
- Draining evolutions
- Waste discharges and spill prevention
- Environmental focus at daily outage meetings

New Management Organization Provides Outage Support



The Outage Schedule Is Achievable

- RFO6 Goal - < 45 days Breaker to Breaker
  - Unit Off Line, RFO6 Begins — May 1
  - Mode 5 Cold Shutdown — May 2
  - Reactor Defueled — May 13
  - Reactor Onload Begins — May 20
  - Turbine Generator on Turning Gear — May 31
  - Mode 4, Startup — June 3
  - NOP/NOT — June 4
  - Reactor Critical — June 7
  - Unit On-line, RFO6 Complete — June 10
  - Unit 3 100% Power — June 12
- Critical Path is the Refueling Sequence

Key Projects Support The Future Performance Of Unit 3

- Steam Generator Work (J-Tube Modification)
- Replacement of "D" Loop Equalization Line Isolation (Valve 3RCS*V132)
- Service Water Coating Inspections
- Terry Turbine Pump Rotating Element Change
- AFW Check Valve Replacement/Inspections
- Loose Parts Monitor System Replacement
- In Mast Fuel Sipping Installation

No Control Room Panel Deficiencies Planned After Outage

Currently have 6 Control Room Panel Deficiencies

- 1 scheduled to complete prior to RFO6
- 5 scheduled to complete during RFO6

Operator Work Arounds Reduced

Currently have 22 Operator Work Arounds

- 1 scheduled prior to RFO6
- 3 scheduled for RFO6
- 10 scheduled on-line during cycle 7
- 8 scheduled during RFO7

Aggressively Addressing Temporary Modifications

Currently have 22 Temporary Modifications

- 5 scheduled prior to RFO6
- 7 scheduled for RFO6
- 9 scheduled on-line during cycle 7
- 1 scheduled during RFO7

Benchmarking Initiatives To Move Towards Best of The Best

- One-Stop-Shop
- Lessons Learned
- Site Wide Involvement

One-Stop-Shop Will Improve Outage Performance

- Command and Control
- Focal point for problem resolution
- Licensed personnel
- Full support staffing
- Safe shutdown support
- 30-minute rule

Lessons Learned Provides Continuous Improvement

- Continuous feedback
- Identify positives, improvements, and out-of-the-box ideas
- Timely sessions to assure lessons not lost
- Exchange details for the next unit's outage

Site Wide Involvement Team

- One site, one team, one set of expectations
- 200+ outage positions
- Savings on outage budget
- More diverse employees
- "Unite The Site"

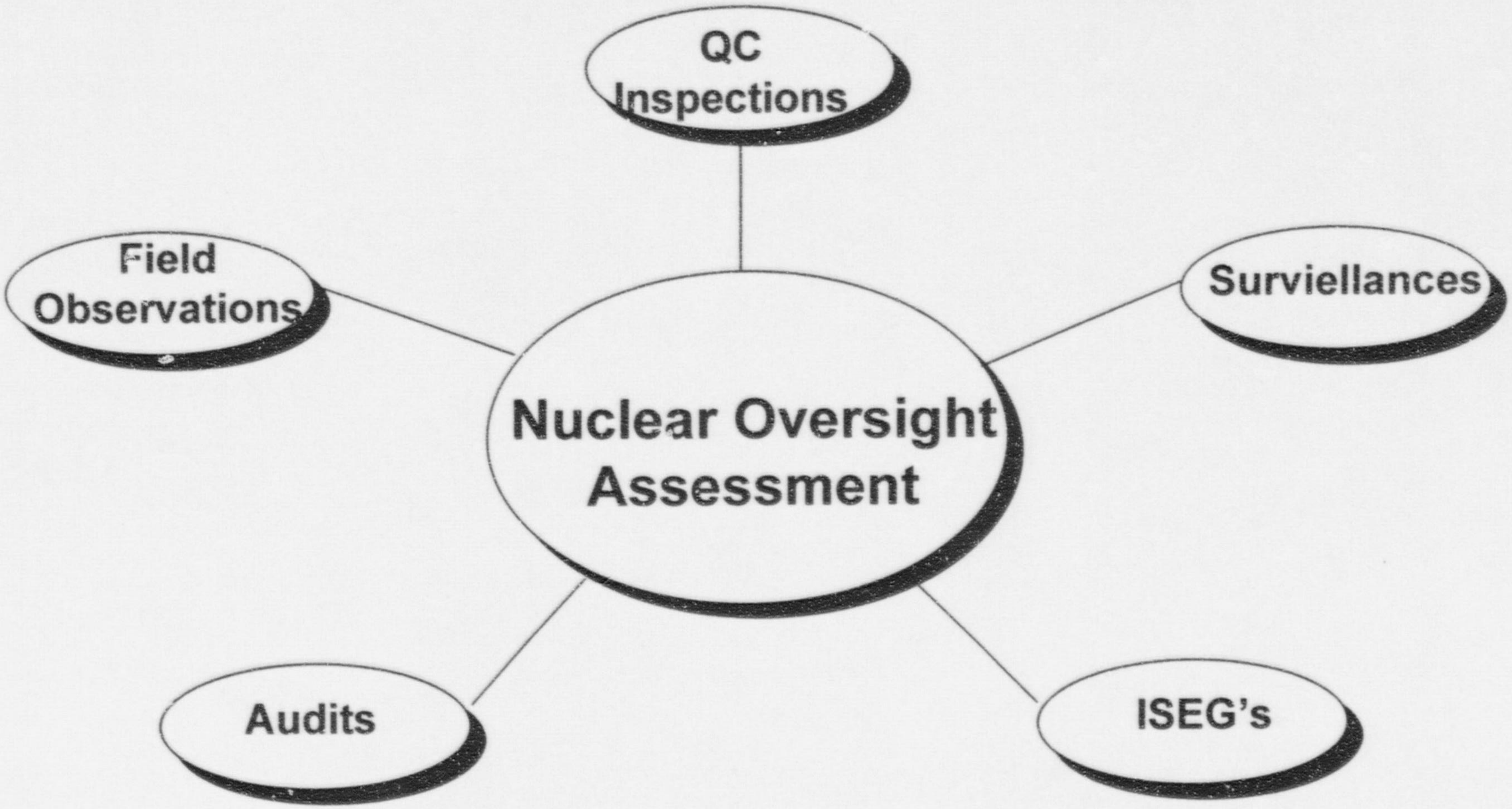
Nuclear Oversight Focus on RFO6 Activities

- Monitor regulatory requirements and commitments
- Provide assessments to ensure plant, worker, and public safety
- Enhance safe, event free operations post refueling

Performance Based Assessments Planned

- Functional area assessments prioritized
  - Relative risk
  - Historical performance
  - Lessons Learned
- Project Team concept
  - Captures knowledge and experience from all disciplines
  - Intrusive review of key activities
  - Direct and timely feedback

Providing Real Time, Integrated Assessment Products



Summary

- Management team focused on a safe outage
- Key element is to reduce aggregate impact
- Inspired worked force working with new initiatives
- Setting a course for safe, event free operations over an extended plant run