U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No. 50-213/89-16

License No. DPR-61

Licensee: Connecticut Yankee Atomic Power Company
P. O. Box 270
Hartford, Connecticut 06141

Facility: Haddam Neck Plant

Location: Haddam Neck, Connecticut

Dates: September 6, - October 17, 1989

Inspectors: Andra A. Asars, Resident Inspector
John T. Shedlosky, Senior Resident Inspector
Peter J. Habighorst, Resident Inspector, Millstone 2

Approved by: Donald R Haverkamp 11/8/89
Donald R. Haverkamp, Chief Date
Reactor Projects Section 4A
Division of Reactor Projects

Inspection Summary: Inspection on September 6 - October 17, 1989 (Inspection Report No. 50-213/89-16)

Areas Inspected: Routine safety inspection by resident inspectors of plant operations; events occurring during the inspection period including elevated reactor coolant system activity; radiological controls; maintenance and surveillance activities including core support barrel removal and inspection, fuel inspection and cleaning, containment spray nozzle flow testing, and containment penetration leak rate testing; security; engineering and technical support activities, including steam generator tube plugging and plug repair; safety assessment and quality verification activities, including Plant Operations Review Committee meetings and written reports; and licensee response to Generic Letter 88-17, Loss of Decay Heat Removal (TI 2515/101).

Results: This inspection period covered the first seven weeks of the 1989 Refueling Outage. The management decision to delay reactor disassembly in response to high reactor coolant system activity was prudent. Appropriate consideration was given to ALARA controls and personnel safety reviews, though the delay impacted the outage schedule (Section 2.2.1). The outage schedule subsequently was greatly impacted by difficulties encountered during core support barrel removal. The licensee also thoroughly and deliberately evaluated that situation and reacted prudently (Section 4.1.1). Enforcement discretion is being taken for a violation of the station procedure governing radiation worker responsibilities in which a worker entered Containment without signing on to the appropriate Radiation Work Permit (Section 3). No new Unresolved Items were identified.

TABLE OF CONTENTS

* The NRC Inspection Manual inspection procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

DETAILS

1. Summary of Facility Activities

At the start of the inspection period, the plant was in Mode 5 and beginning the 15th refueling outage. Reactor disassembly and entry into Mode 6 was delayed due to higher than normal reactor coolant system (RCS) radionuclide activity. On September 17, following extensive RCS degassing, purification, and activity analysis, the RCS was opened and Mode 6 entered. The reactor disassembly began on September 21 and defueling completed on September 25. Debris-induced fuel damage was identified during fuel inspection on September 27. Fuel inspection, cleaning and reconstitution activities were immediately initiated. On September 28, several unsuccessful attempts were made to remove the core support barrel (CSB) from the reactor vessel for inspection. It was later identified that four dowel pins were backed out and one bolt was missing from the CSB thermal shield modifications made during the 1987 Refueling Outage. One of the dowel pins was bent when it came in contact with a hot leg nozzle during the attempted CSB removal. At the end of the inspection period, fuel inspection and cleaning was continuing, while preparations were being made to cut the other three protruding CSB dowel pins to permit CSB removal.

NRC Commissioner Kenneth Rogers visited the facility on September 25. He was accompanied by Malcolm Knapp, Director of the Division of Radiation Safety and Safeguards of Region I. A tour of the plant was made with members of station management and the resident inspectors. Areas toured included the steam generator mock-up facility, control room, switchgear rooms, and containment.

2. Plant Operations

2.1 Operational Safety Verification

The inspector observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

-- control room	-- primary access point
-- primary auxiliary building	-- protected area fence
-- vital switchgear room	-- yard areas
-- radiological control point	-- intake structure
-- Appendix R switchgear building	-- diesel generator rooms
-- auxiliary feedwater pump room	-- turbine building

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with plant technical specification (TS) requirements. Operability of engineered safety features, other safety related systems and onsite and offsite power sources were verified. The inspector observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Routine operations surveillance testing was also observed. Compliance with TS limiting conditions for operation and implementation of appropriate action statements for equipment out of service was inspected. Plant radiation monitoring system indications and plant stack traces were reviewed for unexpected changes. Logs and records were reviewed to determine if entries were accurate and properly identified equipment status or deficiencies. These records included operating logs, turnover sheets, system tagouts, and the jumper and lifted lead book. Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspector also examined the condition of various fire protection, meteorological, and seismic monitoring systems. Control room and shift manning were compared to regulatory requirements and portions of shift turnovers were observed. Control room access was properly controlled and a professional atmosphere maintained.

In addition to normal utility working hours, the review of plant operations was routinely conducted during portions of backshifts (evening shifts) and deep backshifts (night shifts between 10:00 p.m. and 5:00 a.m. and weekend shifts). Extended coverage was provided for 29 hours during backshifts and 18 hours during deep backshifts. Operators were alert and displayed no signs of inattention to duty or fatigue.

2.2 Followup of Events Occurring During Inspection Period

During the inspection period the inspectors provided onsite coverage and followup of unplanned events. Plant parameters, performance of safety systems, and licensee actions were reviewed. The inspectors confirmed that the required notifications were made to NRC. During event followup the inspector reviewed the corresponding plant information report package, including the event details, root cause analysis, and corrective actions taken to prevent recurrence. The following events were reviewed:

2.2.1 Elevated Reactor Coolant System Activity

Prior to shutdown for refueling, the plant had continuously operated for 461 days and reactor coolant system (RCS) activity was stable at about 0.02 μCi/ml (micro Curies/milliliter). Following plant shutdown, activity peaked at about 11 μCi/ml. The licensee elected to delay reactor disassembly and opening of the RCS for about two weeks to facilitate additional RCS degassing, purification, and activity analysis. Frequent RCS gas and liquid samples were taken and results trended. A fuels and chemistry expert from the fuel vendor (Babcock & Wilcox) met with station management on September 15 to discuss the increased activity. It was concluded that the system purification ion exchangers were saturated and therefore ineffective at further reducing system activity. The ion exchangers were changed and RCS activity subsequently reduced.

Prior to opening of the RCS, additional personnel safety precautions were taken in anticipation of increased area gas activity. These measures included clearing containment of nonessential personnel and wearing respirators. The RCS was opened on September 17 without incident.

The inspectors attended the September 15 meeting and monitored the licensee's review and evaluation of the elevated RCS activity. The decision to delay reactor disassembly and the actions taken for personnel safety and ALARA concerns were prudent and conservative.

2.2.2 Turbine Autostop Oil Mercoid Switches Fail Surveillance

During outage calibration on September 22, the turbine autostop (AST) oil mercoid switches were found out of calibration in the nonconservative direction. Initially, the licensee determined this to be reportable in accordance with 10 CFR 50.72 (b)(2)(iii) as an event or condition that alone could have prevented the fulfillment of the safety function of a system needed to shut down the reactor. This determination and the required reports were made on September 23. Further licensee review concluded that this was not reportable because the AST mercoid switches are not taken credit for or required in the event of a turbine/reactor trip. The emergency notification system ENS report was rescinded on October 6.

The inspectors reviewed the licensee's reportability evaluation. The AST mercoid switches are designed to initiate a reactor trip on low turbine autostop oil pressure. The switches are not QA Category 1, are not taken credit for in the accident analysis, and are not part of the reactor protection system technical specifications. Additionally, the as-found setpoints were within 1 psig of the acceptance criteria and would have performed their intended function. The initial determination that this was a reportable event was in accordance with EPIP 1.5-1, Emergency Assessment, Attachment 12.7, which identifies this trip as a reactor protection system trip or actuation signal. The licensee is evaluating changes to this EPIP.

The inspectors concurred with the determination that this event is not reportable and found the licensee's evaluation and corrective actions acceptable.

3. Radiological Controls

During routine tours of the accessible plant areas, the inspectors observed the implementation of selected portions of the licensee's radiological controls program. Utilization and compliance with radiation work permits (RWPs) was reviewed to ensure that detailed descriptions of radiological conditions were provided and that personnel adhered to RWP requirements. The inspectors observed controls of access to various radiologically controlled areas and use of personnel monitors and frisking methods upon exit from those areas. Posting and control of radiation areas, contaminated areas and hot spots and labelling and control of containers holding radioactive materials were verified to be in accordance with licensee procedures. During this inspection period radiological controls for four major work activities were observed, including:

-- steam generator inspection and repair activities,

-- split pin modifications,

-- fuel inspection and reconstitution, and

-- core support barrel removal and inspection.

On October 15, health physics (HP) technicians identified that a radiation worker had entered containment without signing in on an RWP. The worker was a contractor employee supporting steam generator (SG) inspection and repair activities. The individual was acting as an escort for other workers to the SG loop 3 gate, located in the containment lower level outer annulus. A worker briefing was conducted at the SG checkpoint, which is where workers must sign on to the SG RWPs. The individual escorted the workers to the SG loop 3 locked, high radiation gate and remained outside the gate (4 to 15 mr/hr area) as the high radiation gate watch for a period of about 75 minutes. Upon exiting containment, the individual was unable to sign off the appropriate RWP because he had not signed on. Additionally, his pocket dosimeter was reading offscale. The individual's TLD was read and indicated no exposure. Radiological deficiency report 89-10-11 was issued. All steam generator work activities were discontinued until the situation was resolved the following day.

Licensee HP supervisory personnel immediately interviewed the individual to determine if he had signed on to a RWP and which areas of containment he had entered. The individual stated that he had not entered any areas other than the lower level outer annulus and did not know his RWP number. Following the interview, the individual's site access was terminated.

The HP technicians reviewed all RWPs to determine if the worker had signed on to any permit other than RWP 8900428, Support Work for SG. The individual was signed on to RWP 8900554, Non High Radiation, Non Contaminated Areas in RCA Excluding Containment. This RWP does not cover activities inside of containment.

Procedure RPM 2.1-6, Radiation Worker RWP Responsibilities, requires that all persons working in a radiologically controlled area must do so under an approved RWP. Each individual is required to initial the RWP to signify that he has read, understood, and agrees to comply with the RWP requirements. Although the failure to follow procedures constitutes a violation, no Notice of Violation is being issued in accordance with the provisions of 10 CFR Part 2, Appendix C, Section V.G.1, Exercise of Discretion (NCV 89-16-01). The seriousness of this violation is mitigated by the fact that the individual did not enter a high radiation area and did not accumulate any exposure.

On October 16, station management held a meeting with HP and engineering department supervision to discuss this incident. The licensee representatives determined that communication and coordination during SG work needed to be improved. The responsibilities of control over SG activities were reemphasized. Additionally, a radiation safety posting was distributed onsite which reemphasized the need for attention to detail when working in radiation areas, radiation worker responsibilities and a description of recent radiological controls deficiencies.

The radiologically controlled area is divided into zones. The containment building is a zone with two additional zones within the building, the steam generators and the loop areas. A radiation worker entering either of the inner zones must pass the containment zone check point and proceed to the appropriate inner zone check point for briefing and RWP sign in. The ability to gain access to containment without checking in at one of the inner zone check points provides a vulnerability to personnel error. The inspector discussed this with a HP supervisor. The control of the containment zones is being evaluated by the licensee.

The resident inspector discussed this incident with health physics specialists in the NRC Region I Office. It was determined that the licensee's response to this incident and corrective actions were adequate. With the exception of this isolated incident, health physics technician control and monitoring of the activities observed were determined to be adequate.

4. Maintenance and Surveillance

4.1 Maintenance Observation

The inspector observed various maintenance and problem investigation activities for compliance with procedures, plant technical specifications, and applicable codes and standards. The inspector also verified the appropriate quality services department (QSD) involvement, safety tags, equipment alignment and use of jumpers, radiological and fire prevention controls, personnel qualifications, post-maintenance testing, and reportability. Portions of seven maintenance activities were reviewed, including:

-- ste[illegible] generator manway removal,

-- reactor disassembly,

-- service water pump replacement,

-- emergency diesel generator outage maintenance,

-- containment air recirculation fan cooler maintenance,

-- core support barrel removal, and

-- fuel inspection and cleaning.

4.1.1 Reactor Core Support Barrel Removal and Inspection

On September 28, the licensee made several unsuccessful attempts to remove the core support barrel (CSB) from the reactor vessel for inspection of the modifications made during the 1987 refueling outage. During these lift attempts, a protruding dowel pin came in contact with a hot leg nozzle and was bent. All attempts to remove the CSB were halted and an inspection of the interference initiated.

During the 1987 refueling outage, as part of the second ten-year inservice inspection interval, the licensee performed an examination of the CSB. Following removal of the CSB, several defects in the thermal shield attachments were observed and debris was found in the bottom of the reactor vessel. CSB inspection and modifications made during the previous outage are discussed in NRC Inspection Reports 50-213/87-25, 87-27, 87-31, and 88-02. Repair and modifications were made under plant design change record (PDCR) 920, Thermal Shield Support System Repair, and included replacement of support block dowel pins and bolts, relocation of reactor vessel irradiation surveillance material specimens, and installation of six limiter keys and keyways on the upper rim of the thermal shield.

Following the initial CSB removal attempts and with the CSB in the reactor vessel, the licensee inspected the interference using underwater cameras. A preliminary visual inspection was made of all six support blocks and limiter keys and keyways. Three abnormalities were identified, including:

-- three dowel pins were protruding at the 128° limiter key (one of these pins was bent during attempts at CSB removal);

-- one dowel pin was protruding from the 210° support block; and,

-- one bolt was missing from the 270° support block.

At the end of the inspection period, the licensee was preparing to cut the three dowel pins at the 128° limiter key as those pins interfere with CSB removal from the reactor vessel. Following removal of the pins, the CSB will be removed from the vessel and inspected. At that time the full extent of the damage will be known and repair plans can be made.

The inspectors monitored portions of the attempted CSB lifts and inspection of the interference with the reactor vessel, and attended several associated Plant Operations Review Committee meetings. Activities were well coordinated and deliberately executed.

4.1.2 Fuel Inspection and Cleaning

During this inspection period, the licensee conducted ultrasonic testing (UT) of all once- and twice-burned fuel assemblies which will be replaced into the reactor. Preliminary results indicated 213 leaking fuel pins in 67 assemblies. A total of 109 assemblies were inspected.

Visual inspection of the assemblies revealed small fingernail-sized metal chips and shavings accumulated in the region between the lower nozzle and the first spacer grid; an area less than two inches high. All 109 assemblies are being thoroughly inspected and cleaned by the fuel vendor, Babcock & Wilcox. The inspection process includes a close visual inspection of all four sides and the bottom of the assembly. The use of back-lighting permits a thorough inspection between the fuel pins. The debris is being removed with a pick and collected at the bottom of the inspection and cleaning stand. The entire cleaning and inspection process is being videotaped. Depending on the amount of debris present, one to eight assemblies can be completed during one shift.

During the inspection and cleaning, any fuel pins near debris which was difficult to remove are being marked for eddy current inspection during reconstitution. Following inspection and cleaning, the eddy current testing and reconstitution will begin. The licensee has elected to replace the once-burned pins with similar pins from a donor assembly. The twice-burned fuel pins will be replaced with stainless steel dummy pins.

The inspector observed portions of the UT and visual inspections and the cleaning process. Although this effort is the outage critical path activity, the process is being performed deliberately and thoroughly.

4.1.3 Reactor Upper Internals Stand Misplacement

On September 21, when the licensee placed the reactor upper internals on its stand to support split pin modifications, one of the fuel assembly guide pins was damaged. The upper internals remained suspended from the polar crane during the investigation and inspection which followed. It was determined that the upper internals stand had been mispositioned in the refueling cavity.

The upper internals package has two fuel assembly guide pins for each fuel assembly, which provide for equivalent spacing between the fuel assemblies. The guide pin at the A9 position was damaged when it came into contact with the upper internals stand. Visual inspection of the upper internals identified no additional damage.

Licensee review of the circumstances which led to damage of this pin identified that the exact requirements for the upper internals stand placement were not specified by procedure. This stand was used for the first time during the previous refueling outage and placement had not been incorporated into the reactor disassembly or split pin modification procedures.

Following the visual inspection, the stand was repositioned and the upper internals placed onto it without interference.

Following the upper internals split pin modification, the damaged guide pin was removed under plant design change record (PDCR) 981, Reactor Vessel Fuel Assembly Guide Pin Sectioning. The pin removal was required to prevent the possibility that a fuel assembly could be picked up by this pin during a future reactor disassembly.

The inspectors observed portions of the stand placement and guide pin inspection and attended Plant Operations Review Committee meetings concerning the stand mispositioning and corrective actions. No deficiencies were identified.

4.2 Surveillance Observation

The inspector witnessed selected surveillance tests to determine whether properly approved procedures were in use; plant technical specification frequency and action statement requirements were satisfied; necessary equipment tagging was performed; test instrumentation was in calibration and properly used; testing was performed by qualified personnel; test results satisfied acceptance criteria; and, unacceptable results were properly dispositioned. Portions of four activities were reviewed; including:

-- emergency diesel generator testing,

-- containment penetration local leak rate testing,

-- service water pump performance testing, and

-- containment spray header test.

4.2.1 Containment Spray Nozzle Flow Test

On September 14, the licensee performed surveillance procedure ENG 1.7-82, Containment Spray Nozzle Flow Test. Conduct of the test was stopped by a HP technician when large amounts of dust were introduced into the containment air creating minor airborne contamination. The test was terminated immediately and all personnel were evacuated from containment. Plant information report 89-139 was initiated.

This test was performed for the first time during the 1987 refueling outage as procedure SUR 5.7-107. The test involves admitting air flow to the containment spray piping to verify that spray nozzles are free flowing and not clogged. Test personnel stationed on the polar crane use infrared thermography techniques to verify nozzle flow. The containment spray system is not required for reduction of post accident containment pressures and is not taken credit for in the accident analyses. However, the performance of this test is recommended by the licensee Probabilistic Safety Study.

Air samples taken as flow initiated from the spray nozzle identified 2.6E-08 µCi/cc of Cobalt 60. This is equivalent to less than 2% of the maximum permissible concentration of Co-60 specified in 10 CFR 20, Appendix B, Table I. Whole body counts of two test personnel who were positioned on the polar crane identified no internal uptakes. Access to containment was restored, however respiratory protection was required for the next several hours.

Station management reviewed the test conduct and procedural requirements. Procedure ENG 1.7-82 does warn of a possible airborne contamination problem, however this was not expected as it was not experienced during the previous test. Recommendations were made for additional test precautions and prerequisites. At the close of the inspection period the test had not yet been reperformed.

The inspectors reviewed the test procedure, associated radiation work permits, personnel whole body count results, and the licensee response to and evaluation of this incident. The inspectors were concerned that the procedure did not require that one containment hatch door be closed during the test to prevent a potential unmonitored ground release. The potential for ground release had been evaluated in association with the reactor disassembly and the licensee determined that the worst case release would not exceed the allowable limits. However, the inspectors were informed that this would be included in future test prerequisites. The inspectors had no further concerns.

4.2.2 Containment Penetration Leakage Testing

During this inspection period, many containment penetration local leak rate tests (LLRTs) were conducted. On September 30, valve VS-CV-1104 was tested by procedure SUR 5.7-57, Air Monitoring Sample to Containment Check Valve LLRT. The test results exceeded the leakage limits permitted by Technical Specification (TS) 4.4.II. The appropriate notifications were made to NRC.

The TS 4.4.II specifies that the allowable sum of all penetration leakage and isolation valve LLRTs be less than or equal to 0.6 La, which is defined as the maximum allowable containment leak rate and is equal to 0.18 weight percent of the air in containment in a 24-hour period at 40 psig. This leakage limit is equivalent to 650 pounds-mass/day (lbm/day).

Valve VS-CV-1104 is the inboard containment isolation check valve for the air monitoring sample system, penetration P-65. The system is normally isolated and used only when sampling the containment atmosphere. The licensee was unable to quantify the leakage because it exceeded the measuring capabilities of the Volumetrics instrumentation and therefore exceeded TS leakage limits.

Two additional containment isolation valves in separate penetrations have failed the LLRT test acceptance criteria but not the TS leakage limits. The licensee is investigating those failures.

At the end of this inspection period, valve VS-CV-1104 had not yet been disassembled and inspected to determine the cause of failure, and a Licensee Event Report was being prepared.

About 80% of the LLRTs have been completed. The containment building as-found integrated leakage, which includes the minimum pathway leakage for all penetrations, was still acceptable at about 134 lbm/day.

The inspector reviewed the tests and test results for the three failed isolation valves and associated maintenance and surveillance histories for these valves. The leakage tracking methodology and corrective actions were discussed with the responsible engineer. The program was found to be effectively implemented and well-coordinated.

5. Security

During routine inspection tours, the inspectors observed implementation of portions of the Security Plan. Areas observed included access point search equipment operation, condition of physical barriers, site access control, security force staffing, and response to system alarms and degraded conditions. These areas of program implementation were determined to be adequate.

6. Engineering and Technical Support

The inspector reviewed selected design changes and modifications made to the facility which the licensee determined were not unreviewed safety questions and did not require prior NRC approval as described by 10 CFR 50.59. Particular attention was given to safety evaluations, Plant Operations Review Committee approval, procedural controls, the post-modification testing, procedure changes resulting from the modification, operator training, and UFSAR and drawing revisions. The two design changes and modifications reviewed are described in the following report sections.

6.1 Steam Generator Tube Plug Repair Fixtures

Plant design change record (PDCR) 89-976, Steam Generator Tube Plug Repair Fixtures, installed mechanical plug retainers in existing mechanical, ribbed steam generator (SG) plugs. The mechanical ribbed plugs were installed in the SGs during the 1984, 1986, and 1987 refueling outages. The plugs were identified in NRC Bulletin 89-01 (Potential Failure of Westinghouse SG Tube Mechanical Plugs), as susceptible to stress corrosion cracking. The population of plugs to be repaired with retainers includes 588 installed in the four SG hot legs. Four of the 588 plugs are not of the identified susceptible heat lot, however no plug-to-tube identification was previously recorded, and therefore those four plugs will also be repaired.

The plug retainer consists of two components: a cap screw and a locking cup. The locking cup is threaded into the lower plug end and the cap screw is threaded into the plug expander. Finally, the locking cup is crimped onto the cap screw. The design criteria of the plug retainer are: to prevent a potential loose part, to limit maximum leakage to 0.01 gallon per minute at primary-to-secondary operating differential pressure and to withstand accident loading factors detailed in NRC Regulatory Guide 1.121, Bases for Plugging Degraded Steam Generator Tubes. The plug retainers are manufactured of material not susceptible to stress corrosion cracking.

The inspector reviewed the modification design inputs, testing records, and material composition reports from the vendor supplier of plug retainers. The design inputs were well-documented for the plug retainers.

As documented in NRC Inspection Report 50-213/89-05 (Detail 9.0), the licensee prepared a Justification for Continued Operation (JCO) as it related to Westinghouse SG plugs susceptible to stress corrosion cracking. The JCO documented 53 susceptible plugs calculated by a algorithm to potentially fail during the past operating cycle. The expiration of the JCO was September, 1989. The PDCR 89-976 addresses the installation of plug retainers into the 53 susceptible plugs, as well as the remaining Westinghouse hot leg plugs from heat lot NX-3513 (584).

The integrated safety evaluation was reviewed. The evaluation considered the SG tube rupture event in the Update Safety Analysis Report, licensee identified failure modes, structural integrity margins in Regulatory Guide 1.121, technical specification basis, and the seismic evaluations. The inspector concurred with the licensee's evaluations that an unreviewed safety question does not exist in this modification.

The inspector conducted a walk-down of the SG mock-up facility for plug retainer training, robotic manipulation, installation, and ALARA controls. The retainer installation phase included: plug brushing, retainer installation, cap screw installation, visual/audio torque settings of the retainer and cap screw, and crimping tool operation. Each installation step will be conducted by the vendor's robotic machine in accordance with procedure VP-456, Field Procedures for Installation of SG Mechanical Ribbed Plug Retainers. The inspector had no questions concerning the plug retainer installation steps.

The inspector reviewed the ALARA controls for plug retainer installation including: the licensee's pre-outage ALARA overview document, discussions with the inservice inspection (ISI) ALARA engineer, daily ALARA tracking report. and mock-up walk-downs. The ALARA action items include "timed" training at the mock-up, lead shielding (around the pressurizer surge line), use of timed retainer installation steps for training qualifications, vendor previous experience, no SG platform erection, and SG "half-jumps" for nozzle dam installation. The initial ALARA predicted exposures were based on 1987 SG manway surveys coupled with vendor estimated time intervals for key installations. The exposure estimate is 156 man-rem total for SG eddy current testing, SG plug installation, retainer installation, and visual inspections. The licensee's ISI ALARA engineer independent evaluation concluded 138.2 man-rem. The inspector noted good licensee utilization/evaluation of independent radiation exposure evaluations.

At the conclusion of the inspection period, plug retainer installation was complete for the Nos. 1, 2, and 4 SGs with 69, 169, and 292 retainers installed, respectively. Retainer installations in the No. 3 SG were continuing with 46 of 58 retainers installed. Total personnel exposure was about 146 man-rem.

The inspectors observed mock-up training, remote SG tube plug visual inspection, preparation and retainer installation, and health physics coverage of SG activities. No deficiencies were identified.

6.2 Steam Generator Tube Plugging

The PDCR 89-975 documents the licensee's design change for plugging defective SG tubes to comply with Technical Specification 4.10.1, Inservice Inspection of Steam Generator Tubes. The modification is bounded by the number of plugged tubes per generator to support the accident analysis initial condition of reactor coolant system flow rate.

The licensee has selected a Babcock & Wilcox rolled mechanical plug fabricated from Inconel 600 material. On September 8, NRC Information Notice (IN) 89-65, Potential for Stress Corrosion Cracking in Steam Generator Tube Plugs Supplied by Babcock and Wilcox, was issued. The IN 89-65 concludes, until additional evidence becomes available from corrosion tests and/or experience, all Babcock & Wilcox Inconel 600 heats used for plugs should be considered potentially susceptible to stress corrosion cracking. In this regard, PDCR 89-975 documents the continuous distribution of carbides along the grain boundary based on heat lot microstructure review. The stress corrosion cracking is a function of intermittent distribution of carbides. The licensee's modification documentation further concluded that B&W modified the SG tube plug heat treatment practice and quality control procedures to verify appropriate heat treatment.

The inspectors reviewed the design input documents and the integrated safety analysis for PDCR 89-975, and observed portions of SG tube plug installation activities including the eddy current test data evaluation. No inadequacies were noted.

At the end of this inspection period, tube plugging was completed for the Nos. 2 and 4 SGs with 69 and 73 plugs installed, respectively. Tube inspection was continuing in the Nos. 1 and 3 SGs.

7. Safety Assessment and Quality Verification

7.1 Plant Operations Review Committee

The inspector attended several Plant Operations Review Committee (PORC) meetings. Technical Specification 6.5 requirements for required member attendance were verified. The meeting agendas included procedural changes, proposed changes to the technical specifications, plant design change records, and minutes from previous meetings. The PORC meetings were characterized by frank discussions and questioning of the proposed changes. In particular, consideration was given to assure clarity and consistency among procedures. Items for which adequate review time was not available were postponed to allow committee members time for further review and comment. Dissenting opinions were encouraged and resolved to the satisfaction of the committee prior to approval. The inspectors observed that PORC adequately monitors and evaluates plant performance and conducts a thorough self-assessment of plant activities and programs.

7.2 Review of Written Reports

Periodic and special reports and licensee event reports (LERs) were reviewed for clarity, validity, accuracy of the root cause and safety significance description, and adequacy of corrective action. The inspector determined whether further information was required. The inspector also verified that the reporting requirements of 10 CFR 50.73, station administrative and operating procedures, and Technical Specification 6.9 had been met. The following reports were reviewed:

LER 89-13 Design Deficiency Identified in Charging Pump Oil Cooler Circuit

LER 89-14 A & B Service Water Pump Flow Determined Inadequate During Testing

LER 89-15 EG-2A Emergency Diesel Generator Room Fire Door Inoperable

Haddam Neck Monthly Operating Report No. 89-08, covering the period August 1, 1989 to August 31, 1989

Haddam Neck Monthly Operating Report No. 89-09, covering the period September 1, 1989 to September 30, 1989

Haddam Neck Plant Radioactive Effluents Noble Gas Beta Dose Limit Exceeded, dated September 26, 1989

Haddam Neck Plant Bimonthly Progress Report No. 18 for New Switchgear Building Construction, dated September 27, 1989

No unacceptable conditions were identified.

8.0 Generic Letter 88-17, Loss of Decay Heat Removal

The objective of this review, conducted per NRC Inspection Manual Temporary Instruction (TI) 2515/101, was to verify licensee actions and preparations for reduced reactor coolant system inventory in accordance with NRC Generic Letter (GL) 88-17 dated October 17, 1988. Specifically, TI 2515/101 addresses the GL 88-17 short-term program entitled "expeditious actions." The inspector reviewed the licensee's response and implementation of the expeditious actions.

8.1 Training

The licensee is required to discuss with appropriate plant personnel the Diablo Canyon event of April 10, 1987, related events, and lessons learned. Furthermore, the licensee is required to provide training to personnel prior to entry into reduced inventory condition.

The licensee conducted training on mid-loop operations during the licensed operator requalification program and the non-licensed continued training program. All licensed and non-licensed personnel completed training on August 18, 1989. Since issuance of GL 88-17, the licensee has not entered reduced inventory conditions. The mid-loop training topics consisted of past industry events, reactor coolant system (RCS) level and temperature indication problems, review of mid-loop operations procedure NOP 2.4-10, Reactor Coolant System Mid-loop Operation, emergency RCS fill line-ups, loss of residual heat removal (RHR) with/without the reactor vessel head removed, and a video tape on vortexing.

The inspector reviewed the licensee's training information and verified licensed and non-licensed attendance at the training exercises. This item is satisfied.

8.2 Containment Closure

The licensee is required to prepare procedures and controls to reasonably assure that containment closure will be achieved prior to the time at which core uncovery could occur as a result of a loss of decay heat removal (DHR).

Licensee evaluation C2-517-922-RE Section 4.2 calculates the time to core uncovery as a result of a loss of DHR. The calculation assumes that all loop stop valves are closed and no alternate injection sources. The worst case may occur one day after reactor shutdown with RCS level at the centerline of the hot leg. In this case, the calculated time for core uncovery is 1.24 hours. For mid-loop operations, the licensee developed NOP 2.4-10. Step 4.2 requires containment closure prior to reduced inventory operations. Containment closure is defined as equipment hatch closed, one airlock door closed, and each containment penetration closed by a valve or blind flange. This procedure also provides a graph of hours to core uncovery versus time since shutdown based on the engineering evaluation. Procedure NOP 2.13-5, Establishing Containment Integrity, provides specific steps to establish and maintain integrity. The inspector determined that these actions are acceptable.

8.3 Reactor Coolant System Temperature Indication

During mid-loop operations with the reactor vessel head in place, two continuous independent temperature indicators representative of core exit conditions are required. This information should be available to control room operators or an individual located outside the control room with a means for immediate communication with the control room.

Procedure NOP 2.4-10, prerequisite step 4.7 requires that the inadequate core cooling (ICC) cabinets are operable to provide two independent core exit thermocouples (CETs) to measure RCS temperatures. The CETs require a jumper for bypassing the missile shield terminations for the ICC cabinets in order to provide a plant process computer print out and alarm function. The temporary cables were verified available onsite. Adequate assurance exists for the installation and implementation of RCS temperature monitors.

8.4 Reactor Coolant System Level Indications

The licensee is required to provide at least two independent, continuous RCS water level indications whenever the RCS is in reduced inventory.

On December 23, 1988 the licensee responded to NRC GL 88-17 and reported that two drain header pressure transducers would provide RCS level indications. On June 20, 1989 the licensee informed the NRC that this commitment would not be completed as part of the expeditious actions, but would be completed on a schedule in conformance with program enhancements. Alternate level indication will be provided by a remote (control room) digital level indicator with a pressure transducer on the RCS drain header and a temporary tygon tubing arrangement from the drain header to the reactor vessel vent line. Procedure NOP 2.4-10 requires installation of the level instrumentation, verification of consistency in readings during drain down, and periodic monitoring. The inspector noted that RCS water level indication was deferred pending full licensee implementation of the proposed water level indication as part of the program enhancements described by GL 88-17.

8.5 Reactor Coolant System Perturbations

The licensee is required to implement procedures and administrative controls to avoid operations that deliberately or knowingly lead to perturbations to the RCS while it is necessary to maintain the RCS in a stable and controlled condition.

The licensee has established the controls to avoid RCS perturbations in procedure NOP 2.4-10. Prerequisite step 4.12 and precaution steps 5.2, 5.6, and 5.8 provide required mid-loop system boundary, valve line-ups, and agreements between RCS level indications. As documented in detail 8.1 of this report, training on procedure NOP 2.4-10 was provided during licensed operator requalification and non-licensed continued training. These actions are satisfactory.

8.6 Reactor Coolant System Inventory

The licensee is required to implement procedures and administrative controls to provide at least two available or operable means of adding inventory to the RCS (in addition to the RHR pumps).

The licensee has provided four means of inventory injection to the RCS in addition to the RHR pumps. The preferred means (in order) are: purification pump, charging pump, static pressure head of the volume control tank, and gravity fill from the refuel water storage tank. Engineering calculation C2-517-922-RE assumes the RCS is fully vented in determining make-up flow requirements. The charging pump and purification pumps are cold leg injection point sources. For the charging pump, make-up is aligned to an isolated or unisolated loop. The purification pumps are aligned to a high pressure safety injection isolation valve. The capacity and discharge pressure head of both injection sources are sufficient one day after reactor shutdown. Discussions with licensee personnel indicate that procedure NOP 2-4-10 would not be entered until well after one day following reactor shutdown. No deficiencies were noted.

8.7 Hot Leg Flow Paths

The licensee is required to implement procedures that reasonably assure that all hot legs are not blocked simultaneously by nozzle dams unless a vent path is provided to prevent pressurization of the upper plenum of the reactor vessel.

Procedure NOP 2.4-10, prerequisite step 4.4 requires one or more RCS loops to be unisolated to ensure all RCS hot legs are not simultaneously blocked by nozzle dams. This satisfies the requirement of GL 88-17.

8.8 Loop Stop Valves

Licensees that utilize loop stop valves are also required to implement procedures and controls that assure all hot legs are not blocked simultaneously by closed stop valves unless a vent path is large enough to prevent pressurization of the reactor vessel upper plenum.

Procedure NOP 2.4-10, prerequisite step 4.4 requires one or more reactor coolant system loops to be unisolated to ensure all RCS hot legs are not simultaneously blocked. This item is satisfied.

8.9 Conclusion

The inspector concluded that the licensee has adequately addressed the required expeditious actions of GL 88-17. The implementation of two independent reactor vessel level indicators is deferred pending full implementation. The inspector found the engineering calculations for implementation of the mid-loop procedure thorough and well supported.

9. Exit Interview

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. At the close of the inspection period, an exit meeting was held to summarize the conclusions of the inspection. No written material was given to the licensee and no proprietary information related to this inspection was identified.