U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/ Report No.	50-213/93-21
License No.	DPR-61
Licensee:	Connecticut Yankee Atomic Power Company (CYAPCo) P. O. Box 270 Hartford, CT 06141-0270
Facility:	Haddam Neck Plant
Location:	Haddam Neck, Connecticut
Dates:	November 7, 1993 to December 11, 1993
Inspectors:	William J. Raymond, Senior Resident Inspector Peter J. Habighorst, Resident Inspector

Approved by: John F. Rogge 12/29/93
John F. Rogge, Chief Date
Reactor Projects Section No. 4A

Areas Inspected: NRC resident inspection of plant operations, maintenance, engineering and technical support and plant support activities. As an initiative, the inspector reviewed licensee procedures for mitigating a postulated steam generator tube rupture.

Results: see Executive Summary

EXECUTIVE SUMMARY

HADDAM NECK PLANT INSPECTION 50-213/93-21

Plant Operations

Safe facility operation was noted throughout the period. The licensed operator staff performed very well in responding to degraded equipment conditions and in controlling the plant in response to several operational challenges.

The licensee identified mispositioned valves in the residual heat removal (RHR) and fire protection (FP) systems during the period. The two events were instances of poor configuration control, and appear as an adverse trend in the performance by nonlicensed operators. Human factor deficiencies, such as a lack of valve position indication, or poor useability of valve operator extension rods, contributed to the events. Neither of the mispositioned valves resulted in inoperability of the associated system. The failure to properly position the RHR system valve is a violation **(VIO 93-21-01).**

The inspector identified a fire watch log sheet for the diesel rooms that was not accurate in all material respects. The inaccurate log entry did not result in a failure to perform the compensatory fire watch. The issue appears to be an isolated event. The failure to accurately maintain logs of safety related activities is a violation (**VIO 93-21-02**).

Maintenance

Maintenance and surveillance activities completed during the period were acceptably performed and in accordance with administrative requirements. The post-modification testing of the feedwater isolation valves was well controlled, with good coordination by operations, maintenance, and generation test personnel. The automatic bus transfer feature for motor control center 5 was successfully tested on November 10 in accordance with new license requirements.

The maintenance department implemented actions to prevent significant viscosity changes in the hydraulic fluid for the auxiliary feedwater (AFW) turbine hydraulic power units. Further NRC review is required to evaluate whether the changes are effective to reduce the challenges to operability of the AFW system (**URI 93-21-03**).

Engineering and Technical Support

Site engineering and corporate engineering support was timely and thorough to address an industry issue regarding valve factors for motor-operated valves. Engineering support was good to complete a priority review for Haddam Neck valves, and to propose appropriate corrective actions.

Previous licensee calculations concluded that steam generator overfill would not occur during a postulated steam generator tube rupture event. This analysis did not fully consider operator response times. This was identified by licensee actions to validate the calculations by comparing the assumptions to timelines developed using the plant simulator. The licensee completed an acceptable operability determination, using "best estimate" assumptions for the radiological source term, which concluded that the present emergency operating procedures and accident mitigation strategies would safely mitigate the postulated event. However, further licensee action is required to assure that the postulated accident can be mitigated in accordance with the licensing basis assumptions provided in Section 15.2.10 of the Updated Final Safety Analysis Report (UFSAR). This is an unresolved item **(URI 93-21-04).**

Plant Support

Radiological controls for routine operating, test and maintenance activities were good. The plant operations review committee (PORC) performed well during the period to monitor and evaluate plant performance. The PORC review of the proposed design of the MCC 5 automatic bus transfer scheme was particularly thorough and probing.

Significant organizational changes occurred at the facility and the corporate office during the period. The effectiveness of management oversight and engineering support will be the subject of NRC assessment during future routine inspections.

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Note: The NRC inspection manual procedure or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

The unit was operating at full power at the start of the inspection period. The unit was taken to operational Mode 3 on November 19 for a planned outage to replace the leaking main steam safety valve, MS-SV-14. The reactor was taken critical on November 21 following repairs. The main turbine was phased to the grid at 3:25 a.m. on November 22, but tripped on overexcitation. The generator remained off-line to repair the voltage regulator.

The generator was phased to the grid at 3:00 a.m. on November 23, but power ascension was halted on November 24 when operators noted generator load could not be increased above 28%. The generator was taken off-line to repair the governor for the main turbine. The main generator was phased to the grid at 5:53 p.m. on November 24 and ascension to full power continued. The plant reached full power at 3:10 a.m. on November 26 and operated at 100% power for three days.

Plant operators reduced power to 50% following the failure of the "B" main feedwater pump at 10:43 a.m. on November 29. The pump required offsite repair at a vendors facility. Power operation was limited to 50% power until December 11 pending completion of feedwater repairs. Plant load was reduced to 5% full power on December 9 to allow modification and testing of the four main feedwater isolation valves after testing by the Electric Power Research Institute (EPRI) indicated that valve factors were non-conservative. At the end of the inspection period, the "B" main feedwater pump was repaired, and modification of the four main feedwater isolation valves were completed. The unit was at 100% full power at 10:08 p.m. on December 11.

2.0 PLANT OPERATIONS (71707 and 93702)

In addition to normal utility working hours, the review of plant operations was routinely conducted during portions of backshifts (evening shifts) and deep backshifts (weekend and night shifts). Inspection coverage was provided for thirty-five hours during backshifts and thirty-one hours during deep backshifts.

2.1 Operational Safety Verification

This inspection consisted of selective examinations of control room activities, operability reviews of engineered safety feature systems, plant tours, review of the problem identification systems, and attendance at periodic planning meetings. Control room reviews consisted of verification of staffing, operator procedural adherence, operator cognizance of control room alarms, control of technical specification limiting conditions of operation, and electrical distribution verifications. Administrative control procedure (ACP) - 1.0-23, "Operations Department Shift Staffing Requirements" identifies the minimum staffing requirements. During the inspection period, these requirements were met.

The inspectors reviewed the onsite electrical distribution system to verify proper electrical line-up of the emergency core cooling pumps and valves the emergency diesel generators, radiation monitors, and various engineered safety feature equipment. The inspectors also verified valve lineups, position of locked manual valves, power supplies, and flow paths for the high pressure safety injection system, the low pressure safety injection system, the containment air recirculation system, the service water system, and the emergency diesel generators. No deficiencies were noted.

Jumpers

Bypass jumpers were reviewed against the requirements of ACP 1.2-14.1, "Jumper, Lifted Lead, and Bypass Control NEO 8.05, "with emphasis on proper installation and the content of the safety evaluations. The inspector reviewed all jumpers for age, and verified that Plant Operations Review Committee (PORC) evaluations were completed to disposition longstanding evaluations. The jumpers reviewed were found to be in accordance with administrative requirements.

Tagouts

Inspection was performed of equipment tagouts according to applicable sections of ACP 1.2-14.2, "Equipment Tagging." Tagouts were reviewed to verify that the proper equipment was tagged, equipment identified within technical specifications was appropriately controlled, and equipment isolation was proper based on work observations, controlled drawings, and procedural guidance. Tagouts reviewed in depth were: Clearance 931332, "Replacement of Main Steam Safety Valve" and Clearance 931296, "B" High Pressure Safety Injection Pump Isolation. Other tagging operations were reviewed by comparing the tags installed within the plant with the tagout sheets maintained in the control room. Equipment reviewed was appropriately isolated and the tagouts met the technical specification requirements and administrative controls.

Log-Keeping and Turnovers

The inspectors reviewed control room logs, night order logs, plant incident report logs, and crew turnover sheets. No discrepancies were identified, except as noted below. The inspectors observed crew shift turnovers and determined they were satisfactory, with the shift supervisor controlling the turnover. Plant conditions and evolutions in progress were discussed with all members of the crew. The information exchanged was accurate. During attendance at daily planning meetings, the inspector noted discussions were held which identified maintenance and surveillance activities in progress. The inspectors conducted periodic plant tours in the primary auxiliary building, turbine building, and intake structures. Plant housekeeping was satisfactory.

On November 30, the inspector noted that the level in the primary water storage tank (PWST) was at 20,000 gallons and control room annunciator "PWST Low Level" was illuminated. The inspector also noted there was no log entry regarding Technical Specification (TS) 3.7.1.3. The specification requires, to assure an operable supply of water to the auxiliary feedwater (AFW) system, that the PWST have a minimum volume of 80,000 gallons. Alternatively, the TS 3.7.1.3.b LCO action statement allows for the use of an equivalent volume of water from an alternate source. At Haddam Neck, the recycle primary water storage tank (RPWST) is routinely used as an alternate to the PWST to maintain the AFW supply operable.

The inspector determined that the PWST was drained on November 27 to facilitate cleanup of its contents. The control room operators knew on November 27 the reason for the low PWST level and credited the RPWST as the alternate water supply. The inspector confirmed by reviewing the auxiliary operator (AO) - primary side logs that the RPWST levels were maintained greater than 80,000 gallons as required by TS 3.7.1.3.b during the period the PWST was drained. The inspector confirmed, based on interviews with shift personnel, that the operators were completely aware of the tank condition and alternate source of water, but, had failed to log entry into the technical specification. Further, the shift supervisor and operations managment reviews of plant logs from November 27 - 30 also failed to recognize the log discrepancy. The shift supervisor acknowledged the inspector's comments on November 30, and made a log entry regarding TS 3.7.1.3, backdated to November 27 at 5:29 p.m., when operators commenced draining the PWST.

In summary, no adverse conditions resulted from this issue, and the plant fully complied with the technical specifications for an operable supply of water to the auxiliary feedwater system. However, this issue demonstrated a lack of attention-to-detail to assure the logs accurately reflect the status of the facility. This incident appears to be isolated in that past NRC reviews of plant operations have found that the logs are generally very accurate. Similarly, the operators generally perform very well to track entry into technical specification LCOs. No further action regarding this matter is planned at this time. Future routine NRC inspections of plant operating activites will verify the logs properly reflect plant status, and compliance with technical specification action statements.

2.2 Plant Load Reductions

During this inspection period, the plant status varied from routine operation at full power, to a shutdown condition as the operators responded to several events and degraded equipment conditions. The inspector reviewed operator performance in response to these challenges as the plant was started up or shut down in response to the equipment problems. The dates and reasons for the plant evolutions are provided in Section 1.0 above, and are summarized below.

The unit was operating at full power at the start of the inspection period. The unit was taken to operational Mode 3 on November 19 for a planned outage to replace the leaking main steam safety valve, MS-SV-14. The operators isolated and cooled down the #1 reactor coolant loop while maintaining steady state conditions at normal operating temperature and pressure on the other three loops. The reactor was taken critical on November 21 following repairs. The main generator was phased to the grid on November 22, but tripped on overexcitation. The generator remained off-line to repair the voltage regulator. The generator was phased to the grid on November 23, but power ascension was halted on November 24 when operators noted generator load could not be increased above 28%. The generator was taken off-line to repair the governor for the main turbine. The main generator was phased to the grid on November 24 and ascension to full power continued. The plant reached full power on November 26 and operated at 100% power for three days. Plant operators performed an expedited power reduction on November 29 following the failure of the "B" main feedwater pump. Power operation was limited to 50% power until December 11 pending completion of feedwater repairs. During the interim, plant load was reduced to 5% full power on December 9 to allow modification and testing of the four main feedwater isolation valves.

The inspector witnessed operating activities throughout this period to observe the conduct of shift operations in general, and the implementation of plant operating and surveillance procedures. The specific activities observed, along with the associated procedures, were as follows: NOP 2.4-4, "Cooldown of an Isolated Loop;" NOP 2.3-2, "Reactor Shutdown;" NOP 2.4-3, "Shutdown of an Individual Loop;" SPL 10.3-29, "Changing Plant Load for Rod Position Indication System Testing and Turbine Control Valve Test;" ST 11.7-133, "Changing Plant Load for Turbine Control Valve Position Optimization;" and, NOP 2.2-1, "Changing Plant Load." For each activity, the inspector noted that the operators conducted the evolutions in accordance with the applicable procedure, and in a deliberate, orderly manner. There was good communications amongst the operators, and good coordination with plant personnel supporting the load change.

The inspector also observed the operator actions from the control room on November 29 following the failure of the "B" main feedwater pump. The operators performed very well during this downpower transient to stabilize the plant at reduced load. To complete the shutdown, the operator borated the reactor coolant system and inserted control Bank B. Operator control of the plant was hampered by a failure of a master cycler in the control circuit for Bank B. The effect of the failure was to allow unlimited bank insertion, but to inhibit bank withdrawal when the plant reached reduced load as the operator withdrew rods to compensate for the residuals of the boric acid addition. The operator performed very well to limit the deviation in average reactor coolant temperature (Tave) to less than five degrees from the programmed value. The cycler failure did not affect the scram function of the rods. The licensee replaced the faulty component.

Other significant activities included the actions to isolate and cooldown the #1 reactor coolant loop to allow the replacement of valve MS-SV-14. The evolution to isolate a single loop is infrequent, notwithstanding the operators completed the cooldown and heatup evolutions very well. In summary, the licensed operator staff performed very well to respond to degraded equipment conditions and to control the plant in response to several operational challenges.

2.3 Mispositioned Valves (VIO 93-21-01)

During routine testing and reviews of plant operational status licensee personnel identified on three separate occasions valves in plant systems that were not in the intended position. One event involved a valve in the non-safety related primary water system, which was found fully shut on November 13, instead of the intended position of throttled open by one turn of the hand wheel. The second event concerned two valves in the fire protection (FP) system, which were found closed on November 25 instead of the intended position of fully open. The fire protection system is important to plant safety. The last event concerned the discovery on December 2 that a valve in the safety related residual heat removal (RHR) system was throttled about 76% open by stem position, instead of the intended position of full open. Immediate actions in each case were to correctly position the valve, to initiate a plant information report (PIR) to document the discrepancy for plant management review, and to initiate a review to identify how the discrepancy occurred.

In each instance, the mispositioned valve(s) did not cause the associated system to be inoperable. Also, although the discovery of the discrepancies demonstrated good attention to detail by the operators during this period, the findings demonstrated that past operational activities were not completed correctly as intended. Because of the importance plant system configuration control, and the apparent adverse trend in errors by plant personnel, the inspector reviewed the circumstances surrounding the FP and RHR system events during this period. The event involving the primary water storage system was under review at the end of the inspection period. The findings are summarized below.

Fire Protection System Valves

During the performance of SUR 5.1-156, "Fire Protection System Monthly Valve Alignment Check" on November 25, the auxiliary operator (AO) found valves FP-V-163 and FP-V-113 almost fully closed, instead of the intended position of fully open. The shift supervisor was notified, the valves were opened, and a second operator verified the valves were correctly positioned. Licensee investigation determined that the valves had been left closed during work on the fire protection system in October, 1993. The valves were closed to support the use of a temporary fire water supply during a period of inoperability of the diesel driven fire water pump (reference NRC Report 50-213/93-19). The valves were not returned to the open position upon completion of that work as required.

The valves are provided in the design of the fire water system to isolate one of two supply lines between the discharge of the fire water pumps and the main piping loop that provides fire water to the entire site. The valves and the second supply line were installed after original construction of the plant to provide redundancy in the supply piping between the fire water pumps and the main fire water loop, and thereby eliminate the reliance on a single line. Even with both valves FP-V-113 and FP-V-163 closed, the supply of fire water from the electric and diesel driven pumps was assured to the entire fire water header. Thus, the fire water system operability was not affected by the mispositioned valves.

FP-V-113 and 163 are rising stem gate valves that are located in the fire water loop. Both valves are buried beneath the roadway in front of the intake structure, and are thus not accessible for direct observation. Neither valve has any type of position indication, either remote or locally at the valve. The upper part of the valve stem rises to within about 6 inches of the road surface, and is accessible to the auxiliary operator by opening an 8 inch diameter man hole cover in the roadway. To operate the valve, the operator inserts a "T" handle pole on the top of the stem, and spins the handle a specified number of turns in either the open or closed direction.

The licensee determined that the valves operated stiffly making them difficult to operate at certain spots in the stroke. The inspector noted this during a review of valve operation with an auxiliary operator on November 26. Further, the licensee has provided recent emphasis in the instructions to operators to not "overtorque" manual valves. These circumstances, combined with the lack of position indication (a human factors design deficiency), contributed to the operator "error" of not getting the valves fully opened following the October work on the fire water system.

Residual Heat Removal Pump Suction Valve

On December 2 at approximately 2:30 a.m., an AO identified that the "B" residual heat removal (RHR) suction valve (RHR-V-785B) was locked in a throttled open position. The valve is required to be locked fully open. The AO identified the valve misposition by comparing the configuration with the "A" RHR suction valve. Specifically, the "B" RHR valve had valve stem threads visible in the upper yoke area, whereas the stem threads were not visible on the "A" RHR suction valve. The discrepancy was identified during step 6.1.1 of technical specification (TS) surveillance procedure SUR 5.1-4, "Emergency Core Cooling Systems Test [Modes 1, 2, 3 and 4 (Tave >315°)]." The initial corrective actions were to reposition RHR-V-785 B to the locked open position, and document the event in PIR 93-247.

On-site engineering evaluated the function of the RHR system with RHR-V-785B in the "as-found" position, and concluded that the RHR system remained operable. RHR-V-785B is an eight inch manually operated gate valve. The operability determination was based on the valve being 76% open as measured by stem travel, and the determination that the resulting pressure drop would not significantly affect the "B" RHR pump net positive suction head. This conclusion was based on the assumptions in RHR sump recirculation calculations (ref. 86-060-5276M, "CY ECCS Modifications - Maximum RHR Flow vs. Containment Temperature, November 22, 1986). The pressure drop was offset by either high containment pressure (for postulated large break LOCA) or reduced flow (for a small break LOCA). Further, the licensee credited operator action in emergency operating procedure ES-1.3, "Transfer to Sump Recirculation," which identifies the actions needed to mitigate cavitation of an RHR pump.

The inspector evaluated the operability determination and concluded that licensee's justification for RHR system operability was acceptable. The inspector reviewed the test results for the "B" RHR pump obtained during SUR 5.1-4 for the previous two monthly surveillances. The inspector noted that flow and the discharge and differential pressure readings were acceptable, with no significant changes.

The licensee investigated this issue and determined that RHR-V-785B was most likely mispositioned following manipulation of the valve during a tag clearance on October 8, 1993. Clearance 931229 unlocked and closed RHR-V-785B to support repairs to the "B" RHR pump seal cooling line (AWO 93-12811). The post-maintenance test for 93-12811 was the performance of SUR 5.1-4 and visual leakage check of the pump seal cooling line. The surveillance met the acceptance criteria.

The inspector toured the RHR pump and valve area, and discussed the repositioning of the RHR-V-785B during the tag clearance 931229 with the control room operator. RHR-V-785B is located in the RHR pit in the primary auxiliary building. The RHR suction valves do not have local or remote position indications. The valves are located approximately eight feet in the overhead, and the stem/yoke areas are hard to see clearly from the RHR pump operating level due to intervening piping. Each suction valve has an extension rod from the valve shaft to the ground floor (21 foot elevation) of the primary auxiliary building. The extension rods are approximately twenty feet measured in the vertical direction from the valve to the valve operator. The inspector noted that two individuals were used to reposition the valve on October 8, 1993, and that two operators are normally used to manipulate the suction valves. One individual operates the valve locally (in the pit) while the second individual operates the extension rod (on the ground floor). Two individuals are used to reposition the valves because of the excessive force required to manipulate the valves using the extension rods. The extension rods have been damaged in the past. The inspector considers these factors as a contributing cause for the mispositioning of valve RHR-V-785B.

The failure to properly position RHR-V-785B during clearance 931229 was a violation of administrative control procedure (ACP) 1.2-14.2, "Equipment Tagging". Step 1.7.7 of ACP 1.2-14.2 states that tags will be removed and components realigned in the sequence and position specified on the tagging sheet. Tagging sheet clearance 931229 and SUR 5.1-126, "Locked Valve Checklist" Attachment 1 required valve RHR-V-785B to be locked open. Although this issue was identified by the licensee and further is of low safety significance, the inspector was concerned that this was another example of an apparent adverse trend in nonlicensed operator performance (**VIO-93-21-01**).

2.4 Fire Watch (VIO 93-21-02)

On December 6 at approximately 9:30 a.m., the inspector toured the emergency diesel generator rooms. At the time of the inspection, the licensee was implementing compensatory fire watches for both emergency diesel generator fire doors. The inspector noted that attachment 12.7 to administrative control procedure (ACP) 1.2-2.32, "Implementation and Control of Fire Protection Program Requirements," was initialled as completed for the 10:00 a.m. and 11:00 a.m. entries. ACP 1.2-32 attachment 12.7 is used to document performance of a fire watch activity pursuant to technical specification 3.7.7 requirements. The inspector determined that the fire watch was completed for the diesel fire doors on December 6 by the successful completion of the Fire Watch Location Check Sheet. However, the ACP 1.2-32, Attachment 12.7 verification sheet was not accurate in all material respects.

The fire watch program requirements are described in ACP 1.2-32 and operation department instruction (ODI)-177, "Fire Watches." The operations department provides the fire watches; auxiliary operators (AO) perform the fire watch duties. The non-assigned (extra) AO on each shift typically performs the fire watch, as was the case on December 6. The responsibilities of the on-shift fire watch as detailed in ODI-177 are: 1) check each fire watch area for fires; 2) initial ACP 1.2-32, Attachment 12.7; 3) stamp the Fire Watch Location Check Sheet; and, 4) initial the appropriate space. According to ODI-177, once the fire watch patrol has been completed, the fire watch reports to the control room to have a second check done by control room personnel. The licensee also uses the process computer, which is set to annunciate fifteen minutes after the hour, to remind control room operators of the need to verify that the AO completed the hourly fire watch.

Past NRC information concerning falsification of plant records are Information Notice 92-30, "Falsification of Plant Records," and Generic Letter (GL) 93-03, "Verification of Plant Records." As documented in GL 93-03, it is licensee management responsibility to insure completeness and accuracy of facility records. The NRC and the licensee relies on the professionalism of personnel who perform safety related activities, including log taking. Site management treated the finding as a very significant matter and initiated actions to discipline the individual, and to further evaluate his work. Further, the matter was immediately discussed with each operating shift to highlight the event and to assure all operators are sensitive of managment's expectations on the correct performance of work. The results of the licensee's ongoing actions and evaluations will be reviewed during subsequent routine NRC inspections.

In summary, a violation was identified on failure to maintain accurate records. The technical specification compensatory fire watch was verified complete as required. This issue appears to be isolated, based on past licensee findings in response to IN 92-30, as documented in NRC inspection report 50-213/92-10. The safety significance is minimal because the double verification of the fire watch rounds, as documented in the fire watch location check sheet, was complete and accurate in all material respects to ensure the activity was performed. Routine NRC observations of diesel room fire watch activities since 1992 have not identified any other circumstance similar to the December 6 incident. This is a violation of 10 CFR 50.9(a) and Technical Specification 6.8.1a **(VIO 93-21-02)**.

3.0 MAINTENANCE (61726 and 62703)

3.1 Maintenance Observation

The inspectors observed various corrective and preventive maintenance activities for compliance with procedures, plant technical specifications, and applicable codes and standards. The inspectors also verified if appropriate quality services division (QSD) involvement, use of safety tags, equipment alignment and use of jumpers, radiological and fire prevention controls, personnel qualifications, and post-maintenance testing. Portions of activities that were reviewed included:

- AWO 93-14285, Troubleshooting of "B" Vital Inverter
- AWO 93-15094, Feedwater Valve FW-MOV-12 Torque Switch Jumper
- AWO 93-14408, Refill "B" AFW Hydraulic Power Unit
- AWO 93-11897, MS-SV-14, Flange Leakage
- AWO 93-15098, FW-MOV-13 Torque Switch Bypass
- AWO 93-15099, FW-MOV-14 Torque Switch Bypass
- CMP 8.5-112, Wire and Cable Terminations
- PMP 9.5-215.1, Limitorque Motor Operator Removal, Installation and Adjustment
- AWO 93-14846, 1B Steam Generator Feedwater Pump
- AWO 93-14829, Steam Line Channel Calibration
- AWO 93-14703, Main Generator Overexcitation

3.1.1 Troubleshooting of "B" Vital Inverter

On November 16, the inspector observed maintenance electricians troubleshoot the control and annunciator circuitry for the "B" 120 volt vital inverter. The troubleshooting activity was a result of recurrent "Loss of Synchronization" alarms. The inspector observed the shift supervisor approval of the work order, pre-job briefings, and entrance into technical specification action statement 3.8.3.1.b. During the troubleshooting activities, the vital 120 volt bus was supplied from the alternate power source (Motor Control Center-13). The troubleshooting activity involved verification of output waveforms and under/over frequency setpoints. The setpoints were verified acceptable, and no abnormal indications were noted on the output waveform. Investigation into the spurious inverter alarms continued at the end of the inspection period. The inspector concluded that appropriate pre-job briefings occurred, and good communication existed between the control room and the electricians during the troubleshooting to minimize inoperability of the vital 120 volt bus.

3.1.2 Feedwater Valve FW-MOV-12 Torque Switch Jumper

On December 9, the inspector observed the installation and post-maintenance test to install an electrical jumper to bypass the motor-operator torque switch. A pre-job briefing between the outage manager, maintenance electricians, Generation Test personnel, and the system engineer discussed the job sequence, tagging controls, post-maintenance test plan, and communications. The inspector concluded that the pre-job briefing appropriately focused on safety, worker assignments and coordination.

The inspector independently verified the jumper installation based on a review of circuit diagrams. The electrical jumper was correctly installed. The inspector also verified proper response and overlap between the limit and torque switch contacts.

The post-maintenance test was appropriately accomplished and the acceptance criteria was met. The inspector observed good communication between the operations department and electricians to minimize perturbations on steam generator level during valve manipulations.

3.1.3 Refill "B" AFW Hydraulic Power Unit (URI 93-21-03)

The inspector reviewed activities under AWO 93-14408 to drain, flush and refill the hydraulic power unit for the "B" auxiliary feedwater (AFW) turbine. The maintenance was perfromed as a result of the quarterly sampling program for the hydraulic fluid. The most recent sampling indicated that the hydraulic fluid viscosity was approximately seven times higher than the recommended range of 30-60 centistoke. The licensee consulted with the hydraulic oil and pump manufactures. The hydraulic lubricant vendor concluded that the fluid was able to perform its intended function (open the steam admission valve) based on other parameters measured in the sample (ph, clarity, and centrifuge). CYAPCO also based operability on successful monthly operability tests of the auxiliary feedwater system. The cause of the increased kinematic viscosity was water evaporation from the fluid. Water evaporation is expected at sump temperatures of 130 degrees fahrenheit (F). CYAPCo confirmed that sump temperatures have exceeded 130 degrees F during the recent summer months.

The inspector verified that the "B" auxiliary feedwater pump was isolated on November 18. The sump was successfully drained, flushed and refilled. The licensee was considering maintenance department recommendations to enhance cooling or ventilation of the sump, or use of a synthetic fluid that is more tolerant of ambient temperature changes. The inspector considers resolution of this issue, and implementation of maintenance recommendations unresolved **(URI 93-21-03)**. This will be evaluated in future inspections.

3.1.4 MS-SV-14, Flange Leakage

The licensee completed a planned shutdown starting on November 18 to replace the main steam valve MS-SV-14, which had developed a body to bonnet leak (reference NRC Report 50-213/93-17 and 93-19). The use of the valve that had been damaged during testing was found acceptable by the licensee. The inspector noted that the replacement valve was a rebuilt unit obtained from the valve vendor. The replacement valve appeared in good condition. The inspector observed work activities during the shutdown to replace the valve, and verified that the new valve was leak tight on return to service. No inadequacies were identified.

3.1.5 FW-MOV-13 Torque Switch Bypass

The inspector reviewed activities under AWO 93-15098 on December 9 to install a jumper o n the feedwater isolation valve FW-MOV-13. The jumper were controlled in accordance wit h Bypass Jumper 93-0047 and its associated Technical and Safety Evaluation. The jumper w as installed to return each valve to an operable status.

The inspector verified the following during the review of the activity: the work package doc umentation was complete, including availability and use of installation and test procedures; tagging was in accordance with the clearance; supervisory and operations approvals were obtained prior to the start of work; materials issued for the work were in acc ordance with the work package specifications and were suitable for QA Category I applications; and, QC was involved as specified in the work package. The inspector independently verified that #12 AWG wire was used for the jumper, as stipulated in the work package and t he safety evaluation. The inspector also verified the proper placement of the jumper to assur e switch 33/LS was wired in parallel with 33/LS 1. The inspector independently verified proper stroke and timing of the valve FW-MOV-13 during the post maintenance test. No inadequacies were identified.

3.1.6 Main Generator Overexcitation

The inspector reviewed licensee activities to investigate and repair several problems with the main turbine control systems during the period of November 22 through 24. The main turbine was phased to the grid at 3:25 a.m. on November 22, but tripped on overexcitation. The generator remained off-line to repair the voltage regulator. The generator was phased to the grid at 3:00 a.m. on November 23, but power ascension was halted on November 24 when operators noted generator load could not be increased above 28%. The generator was taken off-line to repair the governor for the main turbine. The main generator was phased to the grid at 5:53 p.m. on November 24 and ascension to full power continued.

The generator overexcitation was caused by a failed transducer in the DC voltage regulator (Westinghouse Model M300 DC voltage error detector Module). The failed unit was replaced by a new unit from the plant warehouse. However, this unit was found to be failed when installed in the generator control circuit. Another replacement unit was obtained from the vendor and installed. The second unit worked satisfactorily.

Subsequent licensee review of the governor control circuit identified that the wrong cup valve was installed in the governor main oil pump. The wrong part was installed by the licensee during actions to tune the turbine controls on November 19. The wrong part was installed d ue to a combination of circumstances, some of which were beyond the licensee's control.

Specifically, while removing the main governor on November 19, the mechanic inadvertently dropped the cup valve, which was lost as it passed through the floor grating near the turbine front standard and fell to the lower levels of the turbine building. The cup valve was found about a day later, but had been damaged beyond use. The licensee withdrew a replacement p art from stores and installed it on November 19. However, even though plant workers requested the correct part number, the unit withdrawn from plant stores was the wrong part - an error that was traced to the vendor. The replacement part was similar enough to the original, that without the benefit of having the original and replacement in hand for comparison, the mechanic failed to note that the wrong cup valve was being installed. Further, even though an experienced maintenance supervisor checked the replacement valve b efore its installation, he failed to notice the differences because a coating used to protect the part during shipment and storage "masked" the subtle differences between the replacement an d the correct part. Finally, the replacement part was sufficiently similar to the original so asto present "normal" system parameters (oil pressure, etc.) when the licensee completed post installation testing of the governor before the plant was returned to power. It was not until the licensee tried to raise plant load to 30% power that the effects of the wrong part were manifested for diagnosis. These circumstances also caused the licensee's diagnostic reviews of the governor problems to be protracted.

Notwithstanding the above combination of circumstances, maintenance supervision and plant management completed a self-assessment of the turbine work. This assessment identified ways to change aspects of the job that were under the licensee's control that would lessen thevulnerabilities to the types of circumstances encountered. The inspector had no further comments on this matter.

3.2 Surveillance Observation

The inspectors witnessed selected surveillance tests to determine whether: 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; and, test results satisfied acceptance criteria or were properly dispositioned. Portions of activities associated with the following procedures were reviewed:

- SPL 10.3-29, Changing Plant Load for Rod Position Indication System Testing and Turbine Control Valve Test
- PMP 9.5-285, MCC-5 Supply Breaker X-Relay Drop-Out Verification
- ST 11.7-133, Changing Plant Load for Turbine Control Valve Position Optimization
- SUR 5.2-38.1, (2,3,4), Loop 1 (2,3,4) Steam Line Break Channel Calibration
- SUR 5.7-98, Testing of the Main Feedwater Isolation Valves

3.2.1 MCC-5 Supply Breaker X-relay Drop-Out Verification

The inspector witnessed the performance of this test by maintenance and operations personnel on November 10. This was the first performance of the test, which was written to implement the new technical specification requirements issued on November 1, 1993 as part of Amendment #169 to the plant license. New Technical Specification 3.8.3.1.2 provided a limiting condition for operation for MCC-5 and its automatic bus transfer (ABT) feature and allowed for the test of the ABT with the plant operating at power.

The purpose of the test was to assure continued operability of the ABT by de-energizing the 52X relay in the Westinghouse AK-25 breaker supplying power to MCC-5. In this case, the normal supply was from 480 volt Bus 5, which fed MCC-5 via breakers 9C on Bus 5, and B-MCC5-5-5 on MCC-5. The test plan was to de-energize control power to breaker 9C to drop the 125 volt supply to the associated 52X relay. The 125 volt power was removed by opening the knife switch in the Bus 5 control power supply cabinet. Once control power was removed, test personnel verified proper operation of the 52X relay by listening for the drop sound of the moveable core piece, and by visually verifying that the core piece was in the down position. This action occurred satisfactorily when the test was done on November 10. It is notable that the 52X relay operated properly after being energized continuously since July, 1993. The control power was switched on to secure from the test.

The inspector witnessed the shift briefing before the test and noted good supervisory oversight to assure the test was completed satisfactorily. The current MCC-5 ABT test will only be done in Cycle 18, and on a periodic schedule that will phase out the test over the course of the cycle. No inadequacies were identified.

3.2.2 Changing Plant Load for Turbine Control Valve Position Optimization

The inspector witnessed the conduct of ST 11.7-133 on November 26 by plant operators. The purpose of the test was to adjust control valve positions to the optimum position so as to obtain the best values for reactor coolant system average temperature (Tave), core thermal power, and gross electrical generation (MWe). The test was successfully completed and resulted in the following optimum plant conditions: control valve #3 at 46%, control valve #4 at 68%, core thermal power of 1825 MWth, Tave at 561.98, and an electrical output of 606.6 MWe. The operators controlled primary and secondary plant parameters in a safe, deliberate manner, and there was good coordination between the reactor operators. Maintenance engineering provided good assistance to evaluate turbine conditions and to monitor the conduct of the test.

3.2.3 Loop Steam Line Break Channel Calibration

The inspector witnessed the performance of this surveillance by Instrument & Control personnel on November 26. The test was performed to set the steam line high steam flow trip setpoints in accordance with Technical Specifications 3.3.1 and 3.3.2. The changes were necessitated by the performance of ST 11.7-133 as steam flow changed in response to adjustments to optimize the position of the turbine control valves. The adjustments were made using the Foxboro configurator to change the software in the Spec 200 micro processor cards.

The inspector verified that the Foxboro configurator was connected to the correct Spec 200 card when the calibrations were done for RPS channels 2 and 3. The inspector also noted good techniques and control of the data diskettes containing the revised data, which assured that the channel specific setpoints were inserted into the correct channels. The test was completed satisfactorily and the SUR 5.2-39.1-4 acceptance criteria was met.
I&C personnel performing the test were experienced and very knowledgeable of the equipment and test methods. Test personnel demonstrated good use of procedures and good coordination with the operators. Reactor engineering personnel provided the revised software, and were present to support the calibration. Oversight of the activity by I&C supervision was good. No inadequacies were identified.

3.2.4 Testing of the Main Feedwater Isolation Valves

The inspector witnessed the performance of SUR 5.7-98. "Inservice Testing of Steam Generator Feedwater Isolation Valves FW-MOV-11, 12, 13, 14." The test was performed on December 12 to meet the requirements of Technical Specification 4.7.9.1 to prove operability of the valves following modification and repairs. The valves were modified on December 12 in accordance with Jumper Bypass 93-0047 to address a deficiency in the valve factor (see Section 4.1 of this report for further discussion of this topic).

The post-modification testing included stroking the valves through a complete cycle in both the open and closed directions, and measuring the travel time in each direction. The acceptance criteria were met. The inspector independently verified that FW-MOV-13 operated in less than 70 seconds, and thus met the requirements of Technical Specification 3.7.9. In addition to the testing per SUR 5.7-98, licensee personnel also "red-lined" the valve wiring to verify proper operation of the modified control and indication circuit.

The testing was well controlled, with good coordination by operations, maintenance and generation test personnel. The inspector also noted good communication and feedback of commands by operators during the test. No inadequacies were identified.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

The inspectors reviewed selected engineering activities. Particular attention was given to safety evaluations, plant operations review committee approval of modifications, procedural controls, post-modification testing, procedures, operator training, and Updated Final Safety Analysis Report (UFSAR) and drawing revisions.

4.1 Feedwater Isolation Valves - Nonconservative Valve Factors

The licensee declared the feedwater isolation valves, FW-MOV-11, 12, 13 and 14, inoperable on December 7 at 1:30 p.m. after an engineering evaluation using data from recent testing by the Electric Power Research Institute (EPRI) determined that the valve factors were nonconservative. The valve factors are used to determine the minimum thrust required to be developed by the motor operator to open the valve against the highest differential pressure that the valve is expected to experience under normal operation, and design basis limiting conditions. The feedwater isolation valves are 900 pound class Anchor Darling gate valves. With more than one feedwater isolation valve inoperable, the operators entered Technical Specification 3.7.9, which allowed for continued plant operation for up to 72 hours.

The normally open gate valves are credited in the Haddam Neck accident analyses to mitigate the consequences of a break in a main steam line. The valves receive a signal to close in response to a high containment pressure or safeguards actuation, and are required to close against a differential pressure of 1550 psi. The feedwater isolation valves serve as back up to the main feedwater regulating valves, which also receive a safeguards signal to close under the same conditions. The feedwater regulating valves are air operated globe valves, and are not subject to the same discrepancy as the motor operated valves. Isolation of the feedwater line following a main steam line break is required to limit the mass inventory into the containment, and thus assure that the containment design limits are not exceeded.

The valves most susceptible to having an operability impact from an increase in valve factor were gate valves that have to operate against very high differential pressures, i.e., provide the primary means for isolation of a pipe break. In addition to the feedwater MOVs, the licensee identified that the following valves also required an evaluation for operability:

letdown isolation valve LD-MOV-200, and the block valves (RCS-MOV-567 and 569) which isolate the pressurizer pilot operated relief valves. Of the seven valves of potential concern at Haddam Neck, only the four feedwater MOVs were determined to be inoperable after considering the new EPRI data.

In previous analyses for the valves under the motor-operated-valve (MOV) program, the licensee had assumed valve factors in the range of 0.3 to 0.34. The EPRI testing suggested the minimum valve of the valve factor be 0.4. The thrust required to operate the valve (T req) is directly related to valve factor (VF), as follows:

$$\mathbf{T_{req} = (A_{seat} \; X \; \partial P \; X \; VF) + (A_{stem} \; X \; P_{line}) + Packing}$$

and the terms are defined as: A seat - area of the valve seat; ∂P - differential pressure across the valve disc; A stem - area of the disc stem; P line -pressure in the piping; and, Packing - a friction factor for the valve packing.

The licensee determined that even though the revised valve factor resulted in approximately a 33% increase in thrust required to operate the valve against the design basis differential pressure, the valve operator was capable of providing the required torque. However, with the current torque settings, the licensee concluded that the valve torque switch would stop the valve in the middle of its stroke, thus defeating fulfillment of the safety function in response to a steam line break. The licensee's engineering evaluation concluded that the valves could be restored to an operable status by the installation of a bypass jumper to delay the operation of the valve torque switch until after the valve had completed its full stroke in the closed direction.

The valves are normally closed by the use of a torque switch and an open limit switch in the circuit to provide 125 volt to the closing coil. The closing torque switch is normally bypassed by the open limit switch (33LS1) to assure the operator gets the valve disc off its back seat during the first part of the stroke. The torque switch is normally in the circuit after the valve is about 4% closed. For the bypass jumper, the licensee wired another limit switch contact (33LS16) in parallel with the torque and open limit switches. Switch 33LS16 is on the same rotor used to operate the red "open" indicating light, whose contacts stay closed for the full stroke of the valve from the "fully open" position until the valve reaches the "fully closed" position. Thus, by using switch 33LS16, the torque switch is bypassed throughout the stroke until the valve is starting to contact the seat. At that point, the torque switch operates to stop valve motion as it normally would.

The licensee used the results from the most recently completed VOTES testing on the feedwater isolation valves to confirm that the limit switch settings were appropriate to modify the operation of the torque switch. The VOTES data was used to assure that the valve disc would contact the seat prior to operation of the torque switch. Further, the licensee used the vendor's weak link analysis to assure that operation at higher thrust valves would not jeopardize integrity of the valve pressure boundary or components. The analysis showed that the highest thrust obtainable would be the stalled current thrust that would occur assuming the motor continued to operate after the disc had jammed in the seat. This maximum thrust value was 105,000 pounds, which was much less than the most limiting value of 145,700 pounds determined from the weak link analysis. The licensee also appropriately considered the affects of motor efficiency and inertia.

Bypass jumper 93-0047 was created to modify the operation of the torque switch. The licensee's engineering prepared an associated Technical Evaluation and Safety Evaluation. The jumper and the evaluations were reviewed by the Plant Operations Review Committee on December 8, and were found acceptable, and were found to not involve an unreviewed safety question. The inspector independently reviewed the technical bases for the jumper and the associated evaluations. No inadequacies were identified.

The licensee installed the jumpers on December 9, and completed post modification checks and tests to verify that the jumper was installed properly, and that the torque switch acted to stop the motor after the valve reached the closed position. The plant exited the LCO for Technical Specification 3.7.9 at 1:24 p.m. on December 9.

In summary, the plant staff performed very well to assess new industry data regarding the valve factors for motor operated valves used at Haddam Neck. Engineering support by NUSCO and site engineering was timely and thorough to address operability evaluations for susceptible valves, and to expeditiously complete modifications that assured the main feedwater isolation valves could perform the intended design basis functions.

4.2 Operator Actions For a Steam Generator Tube Rupture (URI 93-21-04)

On November 17, the licensee identified that potentially non-conservative control room operator response times were used in a corporate engineering calculation. Calculation C2-517-1058-RE, "Steam Generator Tube Rupture with New Safety Relief Valves" dated September 10, 1993 concluded that the main steam power operated relief valves can prevent steam generator overfill during a postulated steam generator tube rupture (SGTR). The analysis assumes that operators have equalized reactor coolant system and main steam system pressure within twenty-five minutes from the initiation of a postulated reactor trip. Further, the engineering analysis assumes the initiation of a plant cooldown within eleven minutes from the postulated reactor trip. Based on the operation manager's observation of simulator scenarios, the assumed operator actions in response to a SGTR could result in a water solid steam generator. The operator response times measured during the scenarios drills showed little or no margin to the times assumed in the calculations. The inspector noted that no simulator estimates existed for estimation of operator response times in the engineering calculation. UFSAR section 15.2.10 states that the recovery procedure can be carried out on a time scale which ensures that break flow to the secondary system is terminated before water level in the affected steam generator rises into the main steam line.

The licensee initiated reportability evaluation form (REF) 93-89 on November 24, 1993.

NUSCo's safety analysis engineering group concluded that the condition did not affect equipment operability based on "best estimate" analysis of the radiological consequences of a SGTR and overfill condition were less than the Updated Final Safety Analysis Report (UFSAR) off-site dose analysis. However, further licensee actions is required to assure that the postulated accident can be mitigated in accordance with the licensing basis assumptions provided in Section 15.2.10 of the UFSAR. The resolution of emergency operating procedure response times in comparison to the UFSAR safety analysis assumptions is unresolved **(URI 93-21-04)**.

5.0 PLANT SUPPORT (40500, 71707, 90712 and 92701)

5.1 Radiological Controls

During routine inspections 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) were 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 the 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. Health physics technician control and monitoring of these activities were determined to be good.

5.2 Plant Operations Review Committee

The inspectors 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. PORC meetings were characterized by frank discussions and questioning of the proposed changes. In particular, special PORC meeting on December 6 approved plant design change record (PDCR) 1434, "MCC-5 ABT Re-Design." The inspector observed probing questions on the safety evaluation, content of the post-modification testing, and corporate probalistic risk assessment input to the modification. Items for which adequate review time was not available were postponed to allow committee members time for further review and comment. The committee closely monitored and evaluated plant performance and conducted a thorough self-assessment of plant activities and programs.

5.3 Review of Written Reports

Periodic 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 inspectors determined whether further information was required. The inspectors also verified that the reporting requirements of 10 CFR 50.73 and Technical Specification 6.9 had been met. The following reports were reviewed:

- **Monthly Operating Report for October, 1993**

- **Special Report, Wide Range Nobel Gas Stack Monitor Inoperability**

- **LER 93-17-01, Both Service Water Trains Inoperable During Pump Maintenance and Strainer Cleaning**

The plant was in the TS 3.7.3 action statement on November 1, due to the inoperable "D" service water (SW) pump. This pump was removed from service for repairs on October 31. The licensee trended the conditions of the alternate SW header, and noted that the "A" and "B" pump strainers were fouling and had to be cleaned prior to reaching an inoperable condition in which loss of function would occur. Thus, with the "D" SW pump inoperable the licensee entered TS 3.0.3 action statement at 5:50 a.m. on November 1 as the "A" and "B" SW pumps were removed from service to clean the associated strainers. The licensee staged the personnel and material needed to perform the work and completed the operation in 10 minutes. The strainers were cleaned sequentially, and the header was returned to an operable status to exit the action statement at 6:00 a.m. Recurring fouling conditions required the above sequence to be repeated again prior to the return of the "D" SW pump to service on November 3.

The inspector noted that the alternate SW header remained fully functional since the affected pump remained available to the operators upon demand, and the strainer cleaning operation was completed in a well controlled and deliberate manner. Based on the above, plant safety was not compromised during the brief period that the alternate SW header was "technically" inoperable. However, the licensee reported this event in accordance with by 10 CFR 50.73(a)(2)(i)(B) as a condition prohibited by the technical specifications.

In LER 93-17, the licensee stated that a change to Technical Specification 3.7.3 would be submitted to preclude the need to use TS 3.0.3 to clean SW strainers. The matter is tracked by NRC Report Item 50-213/93-19-01. The inspector identified no inadequacies in the licensee's reporting of this event. This item is closed.

5.4 Follow-up of Previous Inspection Findings

Licensee actions taken in response to open items and findings from previous inspections were reviewed. The inspectors determined if corrective actions were appropriate and thorough and whether previous concerns were resolved. Items were closed where the inspector determined that corrective actions would prevent recurrence. Those items for which additional licensee action was warranted remain open. The following items were reviewed:

- (Closed) Unresolved Item 93-16-02, Bulletin 88-02 Primary Leak Rate Calculation

This item was unresolved pending further review of the response to NRC Bulletin 88-02 and plant procedures directing operator actions in response to a steam generator tube leakage. This review was completed on November 9 with site engineering, and considered the following references: CYAPCo letters to the NRC dated May 27, 1993 and August 1, 1991 in response to Bulletin 88-02; and, procedures AOP 3.2-31, "Reactor Coolant System Leak Rate" and AOP 3.2-2, "High Activity Level."

Prior CYAPCo actions in response to Bulletin 88-02 included the revision of station procedures to assure timely operator actions in response to steam generator tube leakage, and the completion of a long term engineering review of the causes for the North Anna steam generator tube rupture event. The objective of the enhanced procedures was to assure the steam generator leakage monitoring program included provisions to shutdown the plant prior to experiencing a North Anna type event.

During this inspection, the inspector noted that the licensee's engineering evaluation concluded based on a fluidelastic stability analysis that the Haddam Neck Model 27 steam generators are not susceptible to the North Anna type event. This evaluation was accepted by the NRC in safety evaluation by the Office of Nuclear Reactor Regulation dated June 2, 1993. Notwithstanding the above conclusion, the licensee plans to continue to use the enhanced leakage monitoring procedures.

The inspector noted that the steps previously incorporated by the licensee in AOP 3.2-31 assured the operators adequately monitored developing trends in steam generator tube leakage. The steps in AOP 3.2-31 were further sufficient to assure that plant power would be reduced below 50% at least 5 hours before the onset of significantly degraded tube conditions. This point was assured by AOP 3.2-31 in spite of the lack of explicit language in the procedure stipulating that this was the intent of the instruction. Further, the instructions in procedure AOP 3.2-2, which would also be in effect for a steam generator tube leak, explicitly direct the operator to reduce power to less than 50% with leakage exceeding the Technical Specification limits. This instruction also would assure timely action prior to the onset of significantly degraded tube conditions. Finally, the licensee intends to enhance station procedures by adding the guidance in AOP 3.2-2 to AOP 3.2-31.

Based on the above, the inspection concluded that the licensee met his commitments relating to the actions required by Bulletin 88-02. This item is closed.

- (Closed) Unresolved Item 92-12-01, Design Bases of the LTOP Relief Valves

This item was open pending further NRC review of the reactor coolant system (RCS) pressure transients on July 7 and 9, 1993, and NUSCO calculation 77-502-49GM regarding the low temperature overpressure (LTOP) relief valves.

Pressure increase transients on the above dates during the refueling outage were mitigated by quick operator action and the operation of the LTOP relief valves. The highest RCS pressure recorded for each transient was 430 psig and 455 psig, respectively. Technical Specification (TS) Figure 3.4-4 limits reactor pressure to 425 psig when RCS temperature is less than 140 degrees fahrenheit. The TS value includes an allowance for instrument uncertainty of 60 psi, such that the limit on actual RCS pressure is 485 psig. The licensee previously demonstrated (Report 93-12) that the TS limit was not exceeded during either July event when the actual instrument uncertainties were used.

The inspector questioned whether the LTOP had functioned as designed since the indicated pressure was above 425 psig, which was the implied pressure limit in calculation 77-502-49GM. The licensee addressed the inspector's concerns in engineering memorandum EN-93-0591 dated November 9, 1993. Calculation 77-502-49GM was completed in 1978 to support installation of the LTOP system. The analysis was not the calculation of record to size the relief valves, but rather was performed to calculate the relief valve flow rate which would give a 45 psi pressure drop in the piping between the RCS and the relief valves. The calculation showed that when the additional pressure drop is accounted for, a single LTOP train could pass sufficient flow to assure that the pressure limits would not be exceeded.

Refinements in the analytical techniques since 1978 have allowed the Appendix G limits to increase. The Appendix G pressure limit is now 636 psig (including a 60 psi instrument uncertainty). Further, calculational methodologies have improved to consider additional uncertainties, including: a tolerance on the relief valve setpoint (3%), "accumulation" during operation of the valve (10%), the pressure drop in the piping between the pressurizer and the relief valves, elevation head from the reactor vessel to the top of the pressurizer, and the differential pressure attributable to reactor coolant flow. The licensee's evaluation described in EN-93-0591 demonstrated that, even after including the uncertainties listed above, the present LTOP relief valves operating with a 380 psig lift setpoint are adequate to limit RCS pressure to prevent exceeding the Appendix G limits.

Based on the above, the inspector identified no inadequacies in the design or operation of the LTOP valves. This item is closed.

- (Open) Unresolved Item 93-04-01, Acceptance Criteria for Pump Vibration

This item was unresolved pending a licensee review of the required action and alert limits specified in pump surveillance procedures. The licensee review was predicated on NRC inspection 50-213/93-04 results where the inspector concluded that pump absolute upper limits on alert and required action ranges were not developed. The current inservice test program implements ASME Section XI 1983 Summer edition. The licensee compared current program vibration limits to ASME/ANSI OM-1988 addenda to ASME/ANSI OM-1987, Part 6, Inservice Testing of Pumps in Light-Water Reactor Power Plants ("OM-6"). OM-6 program requirements are not currently part of the licensee's approved ASME Section XI program.

Based on the licensee's programmatic review, they concluded that implementation of OM-6 was appropriate. The licensee currently plans to implement the provisions of OM-6 by October, 1994. To implement the program in its entirety, the licensee has initiated a review between engineering and maintenance departments to identify root cause and corrective actions to reduce the vibration levels of the high pressure safety injection (HPSI) pumps. The HPSI pumps currently meet the established inservice test requirements, however, they periodically exceed OM-6 absolute values. This item will remain open pending completion of licensee activities to reduce HPSI pump vibrations, and implementation of the provisions of OM-6 to the inservice test program.

5.5 Organizational Changes

On November 8, the licensee announced the following organizational changes at Connecticut Yankee Atomic Power Company. The on-site engineering organization now has a Director of Engineering, and two managers (Manager of Technical Support and Manager of Design). The Director of Engineering reports to the Vice-President Nuclear Engineering Services. The previous on-site engineering organization had a Manager of Engineering reporting to the nuclear unit director. The changes in the engineering organization went into effect on December 5, 1993.

On December 3, the unit director announced his retirement from Connecticut Yankee Atomic Power Company. Additionally, the Northeast Utilities restructured into three groups: Energy Resources, Retail Business, and Corporate Support. Mr. Robert E. Busch was assigned President of the Energy Resource Group. The energy resource group has NU's power production from the nuclear units. The chief nuclear officer executive vice-president-nuclear, Mr. John Opeka, remains unchanged. The effectiveness of management oversight and engineering support will be the subject of NRC assessment during future routine inspections.

6.0 EXIT MEETINGS

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.

In addition to the exit meeting for the resident inspection held on December 10, the following meetings were held for inspections conducted by Region I based inspectors.

Report No.	Inspection Dates	Reporting Inspector	Areas Inspected
50-213/93-23	11/15-18/93	E. King	FFD Program