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REGION I

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Licensee:	Connecticut Yankee Atomic Power Company P. O. Box 270 Hartford, CT 06141-0270
Facility:	Haddam Neck Station
Location:	Haddam, Connecticut
Dates:	September 21, 1996 - November 15, 1996
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EXECUTIVE SUMMARY

Haddam Neck Station
NRC Inspection Report No. 50-213/96-11

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a seven-week period of resident inspection; in addition, it includes the results of announced inspections by regional specialists.

Plant Operations:

Licensee corrective actions were ineffective in preventing a reactor dilution on September 26, 1996. Operations personnel did not properly monitor the transfer of water to the refueling water storage tank, did not investigate potential dilution of the emergency boration flowpath, and did not follow normal operating procedure (NOP) 2.6-3. No preventive maintenance program existed for valve (BA-V-367) that was suspected of leaking-by. This was an apparent violation of 10 CFR 50 Appendix B Criterion XVI.

The upgrade of various operating procedures was appropriate. The quality and detail in the procedures improved when compared to the procedures prior to September 1, 1996. A violation of technical specification (TS) 6.8.1 was identified whereas the licensee did not have a procedure for a fuel handling accident. The emergency operator procedure (EOP) exercise on a postulated cavity seal leak was successfully implemented by the refueling crane operators. The training for operators appropriately focused on the details and purpose for the significant changes to operations shutdown procedures.

The reactor drain down and actions to evaluate cavity seal leakage were acceptable. Actions to prepare the plant for defueling were thorough. The defueling operations were safely conducted utilizing good teamwork and communications. The refueling senior reactor operators (SROs) maintained good management oversight and professional demeanor. Training records and the content of refueling-related training material were acceptable. The licensee did not have a training program description and implementing procedure for conducting refueling operations and fuel movements that outlined management's expectations for the training of licensed operators and contractor personnel.

Maintenance:

The licensee addressed several significant material deficiencies prior to entry into the refueling mode and completing core offload. The residual heat removal (RHR) pump failed due to the rotation of the baffle, which was caused by the inadequate sizing and spacing of the oil baffle seal. A contributor to the inadequate corrective actions to resolve the problem was the lack of the pump vendor drawings. Actions were completed to modify and significantly upgrade the preventive maintenance checks performed on the refueling equipment. New tools were used to facilitate fuel movement in the spent fuel pool. The plant mechanics were not provided specific guidance on the maximum torque for fasteners on threaded cast iron flanges in the fire protection system.

The surveillance test to verify operability of the spent fuel building ventilation system was not adequate to ensure that acceptable air flow is achieved. This surveillance inadequacy

resulted in a historical violation of the technical specifications to maintain adequate ventilation flow during fuel movement. Additional calibration program and surveillance test deficiencies resulted in apparent violations regarding the heat trace circuits for the boric acid system, and the testing of a containment penetration.

The licensee addressed several significant deficiencies in the spent fuel cooling system. The licensee identified flaw indications in the spent fuel pool (SFP) service water system (SWS) supply lines during the Inservice Inspection (ISI) of five welded pipe supports. NRC review included the location of the reported indications, the description and nondestructive techniques used to characterize the indications, the evaluation of the SWS supply line operability, and the corrective action taken to preclude failure of other SFP SWS supply line piping. The safety significance of the findings of "pipe lap" defects in the supply pipe was satisfactorily evaluated. The expanded inspection of all SFP SWS supply pipe at the support hangers, the metallurgical characterization of the defects, the NDE examinations of the defects, the analytic evaluation of the defects, and the corrective action taken was consistent with good engineering practice.

Engineering:

Engineering support for plant operations showed mixed performance. The initial decision regarding operational readiness of the spent fuel pool cooling system for defueling operations was non-conservative with respect to the technical specifications and the implementing surveillance procedure. A planned modification to correct a long standing deficiency changed a check valve design and location was completed prior to defueling activities. This modification was implemented to improve the cooling system configuration. The temporary modification to supply cooling water to the spent fuel pool was performed satisfactorily, with appropriate contingency planning and monitoring of pool temperatures.

The inspector noted a lack of engineering rigor for a past modification to protect safety equipment from an internal flood scenario. The modification did not require flood barrier installation for approximately thirty-five (35) penetrations. This failure resulted in a non-conservative flood analysis regarding operator response time to mitigate the event. This condition is considered an apparent violation of 10 CFR 50 Appendix B, Criterion III. Inadequate engineering support was identified regarding the safety-related instrumentation setpoint calculations and calibration procedures. Two apparent violations were identified regarding the calculation of instrument setpoint allowances, and for the corrective actions taken for failed instrument calibrations. The inspection also identified weaknesses in the independent verification process. These weaknesses were evident in the setpoint reviews and also in a technical specification clarification that was issued for the reactor vessel level indicating system.

The licensee failed to implement two commitments in response to a violation and a deviation due to less than adequate internal assignment development and inexperienced personnel in the licensing organization. Although actions were completed to address deficiencies in the procedure used to assess control room habitability, the bases for the use of portable breathing apparatus was found to be inadequately supported by engineering calculations. Further NRC review is warranted to determine whether the licensing basis for the spent fuel pool cooling system is adequately defined relative to single failures. The failure to make a prompt report regarding plant operation outside the design basis due to an inoperable B residual heat removal pump was a violation of 10 CFR 50.72.

Plant Support:

The licensee maintained an effective security program. Management support is ongoing as evidenced by the timely completion of the vehicle barrier system and the installation of the biometrics hand geometry system for more positive plant access control. Alarm station operators were knowledgeable of their duties and responsibilities, security training was being performed in accordance with the NRC-approved training and qualification plan and the training was well documented. Management controls for identifying, resolving, and preventing programmatic problems were effective and noted as a programmatic strength. Protected area detection equipment satisfy the NRC-approved physical security plan (the Plan) commitments, and security equipment testing was being performed as required in the Plan. Maintenance of security equipment was being performed in a timely manner as evidenced by minimal compensatory posting associated with non-functioning security equipment, and documentation weaknesses noted during the previous inspection had improved. As an addition to the inspection, Section 6.8 of the Plan, titled Keys, Locks, Combinations and Related Equipment was reviewed. The inspector determined, based on discussions with security supervision, procedural reviews, and by performing an inventory of the key storage cabinets, using the licensee's lock and key accountability documentation, that the locks and keys were being controlled and maintained as described in the Plan.

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REPORT DETAILS

Summary of Plant Status

At the start of the inspection period, the plant was in cold shutdown (Mode 5) with the reactor and pressurizer vented. The plant was in a recovery mode with activities in progress to repair or address degraded RHR system deficiencies and thereby restore redundancy to the shutdown cooling function prior to proceeding with the vessel disassembly and core offload. The reactor operated in Mode 5 and 6, and then entered operational Mode 0 when the core was completely offloaded during the period. The licensee ceased most outage activities during the September 1, 1996 nitrogen intrusion event, which were not recommenced.

The major operational and outage milestones achieved included: repair and restoration to service of the B RHR pump on September 25; evaluation of a pin hole leak in the RHR heat exchanger inlet valve RHR-V-791A and obtaining code relief from the Nuclear Regulatory Commission (NRC) on October 7; completion of items to remove a stop work order placed on the plant by the Nuclear Safety Organization (NSO) group and needed to correct deficiencies identified by the licensee Independent Review Teams root cause evaluation for the September 1 nitrogen intrusion event; drained reactor water to the refueling reference level on October 28; the completion of actions needed to assure readiness to begin refueling - Mode 6 was entered on October 31; lifting the reactor head on November 6; filling the reactor vessel and refueling cavity to 23 feet on November 7; the removal of the reactor internals on November 11; the completion of actions to address material deficiencies in the spent fuel cooling system to assure the spent fuel pool was ready to receive the fuel from the reactor; the completion of actions needed to assure readiness to begin core offload, which began on November 13; and, the removal of all fuel from the reactor - the core offload was completed on November 15, 1996.

Organizational Changes

Significant organizational changes and developments occurred. A new President and Chief Executive Officer for Northeast Utilities was appointed in September and further management changes were announced as part of a Recovery Organization for the five NU nuclear plants. A new Operations Manager was selected, and the plant staff was reorganized in October to place three Directors at the site in the ares of engineering, work services and unit operations. The board of directors for the Haddam Neck joint owners met on October 9 to review the results of the economic analysis, which was not favorable for continued plant operation. The owners announced that the permanent shutdown of Haddam Neck was likely. The licensee essentially halted outage activities except as necessary to support the core offload. On November 18, the licensee announced plans for staffing reductions and organizational changes needed to support plant decommissioning. The licensee initiated plans to reduce site staffing in stages starting in April 1997 and to achieve a final decommissioning organization by December 1997. Further decisions regarding future operations were deferred pending a vote by the board of directors, which was scheduled for early December 1996.

On October 23, the NRC announced the creation of the Office of Special Projects that was effective on November 4. The new organization was established for the oversight of activities at Millstone and Haddam Neck. The Director of the Special Projects, Dr. William Travers, toured the site on November 5 and met with the senior site management. Dr Travers was accompanied by Mr. Jacque Durr during the tour.

I. Operations

O1 Conduct of Operations[1]

Using Inspection Procedure 71707, the inspectors conducted periodic reviews of plant status and ongoing operations. Operator actions were reviewed during periodic plant tours to determine whether operating activities were consistent with the procedures in effect, including the alarm response procedures.

O1.1 Draining to the Refueling Reference Level

a. Inspection Scope (71707)

The purpose of this inspection was to review licensee procedures and observe licensee controls and management oversight for the draining of the reactor vessel in preparation for removing the head.

b. Observations and Findings

The licensee prepared a new procedure NOP 2.6-12, Draining the RCS in Mode 5 and 6, for this evolution. The inspector reviewed the procedure for content and technical adequacy. The procedure provided the operator guidance on the flow paths to use for draining to the refueling reference level, the required valve lineups, the limitations on the rate of draining and the use of diverse level indications to confirm actual level, and guidance on monitoring the evolution for unanticipated conditions.

The inspector observed on October 28 the conduct of the drain down to a level of about 10 inches below the vessel flange. The crew conducting the evolution had previously reviewed and practiced the evolution. The pre-job brief was thorough. The evolution was monitored by the shift mentors and a licensee management representative. The drain down was completed initially by opening valve PU-V-275 to divert water to the refueling water storage tank; the evolution was completed by draining to the waste disposal tank via valve WD-V-210. The operators were very attentive to the controls and indications during the evolution, and monitored pressurizer level and the cavity level indication system.

c. Conclusions

The drain down was completed without incident, and in a well controlled manner.

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[1] Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

O1.2 Reactor Cavity Seal Leak

a. Inspection Scope

The inspection scope was to review the licensee's response to a leak in the reactor cavity seal.

b. Observations and Findings

Background

In 1986, the licensee installed a new, permanent refueling cavity seal ring as part of PDCR 85-781. The seal is a solid ring that bridges the space from the cavity floor to the reactor vessel flange. The seal ring incorporates a flexible metal membrane which is part of the annulus seal, and provides for relative displacement of the reactor vessel and the reactor cavity during plant operations. The primary seal is attached at both the reactor and cavity ends by all welded joints. A secondary type seal is installed as a backup to the flexible membrane, which limits the possible flow area should the primary barrier fail. The seal ring also has four hinged hatches, which are open during normal operations, and closed for refueling. The hatches are the only non-welded gasketed joints in the seal. Each hatch is sealed by a set of double gaskets made of an elastomer material; each gasket is mounted in a separate groove on the edge of the hatchway. The hatches have provisions for leak testing with air and were tested to assure proper seal at the start of this refueling. Finally, a catch basin with tell-tale drain is mounted below the entire seal arrangement to allow monitoring from the welded and gasketed joints. The leak detection system collects leakage from the north (loop 1/2) and south (loop 3/4) halves of the seal plate.

Leak Event

The licensee finished preparations to fill the reactor cavity as part of the core offload sequence. The reactor head was lifted and stored at about 3:00 a.m. on November 5, and the licensee began to transfer water from the refueling water storage tank starting at 4:43 a.m. The intention was to fill the cavity to the refueling level with at least 23 feet of water above the top of the core, corresponding to a level of about 560 inches on the cavity level indication system (CLIS).

The operators stopped the cavity fill with the level at 479 inches at 9:50 a.m. on November 6 when excessive leakage was identified from the cavity seal leakoff tell tale drain. The acceptable leak rate limit to support fuel movement established by the Westinghouse refueling procedure was 200 drops per minute, or 16 ml/min. The measured leak rate varied slightly, but was about 10 times the allowable limit at 200 to 250 ml/min (or about 4 gallons per hour). The leakage stabilized at about 160 ml/min on November 5. The core offload was delayed starting on November 5 as the cavity leak was investigated and evaluated. On November 6, after concluding that the safety benefits outweighed possible negative safety implications, the licensee continued the cavity fill to the 23 ft level. The leakage increased slightly to 180 ml/min at that time.

The licensee's engineering evaluated the leakage with the assistance from Westinghouse (the seal designer) and maintenance. Divers were used to complete an air leak test of the hatches. Although all four hatches showed acceptable leakage, the results were deemed ambiguous due to the possibility that the underwater test did not check the entire sealing surface. The licensee completed and approved technical and safety evaluations, which concluded that the most probable source of the leak was from the gasketed hatch joints, and that catastrophic failure was highly improbable. The technical evaluation considered the ruggedness of the seal ring design, the expected stresses on the welded joints from refueling and normal operations, as well as from design basis events, such as earthquake and fuel drop loads. A new leakage limit of 2 liters/min was established, corresponding to a flow area of 0.004 square inches, which was not considered significant for weld failure.

Procedure guidance was provided to define operator periodic monitoring of the leak rate, as well as expected actions if limits or total leakage or rate of increase were exceeded. The operators monitored the leakage from the tell tale drain using a closed circuit television camera with readout in the control room; the leak rate was trended. The operators also measured leakage as needed depending on leakage trends. The licensee recommenced the defueling sequence with the removal of the vessel internal package at 12:22 a.m. on November 11. The cavity seal leak rate slowly and monotonically decreased and became very small (10 ml/min) by the time core offload was completed.

c. Conclusions

Licensee actions to evaluate the cavity seal leakage were acceptable, with good support provided by engineering and maintenance.

O1.3 Defueling Activities

a. Inspection Scope

During the week of November 11, 1996, the resident inspector staff with the assistance of one region based NRC inspector, conducted a performance-based inspection of the Haddam Neck's defueling operations using NRC Inspection Procedure 60710, "Refueling Activities."

The purpose of this inspection was to evaluate the effectiveness of the licensee's defueling activities. The inspection consisted of observations of defueling activities in containment, in the spent fuel pool, and in the control room, and to independently verify adherence to various procedural and technical specification requirements. The inspectors reviewed the training material and content provided to licensee operators and contractors hired to perform defueling activities.

b. Observations and Findings

The inspectors observed approximately 60% of the fuel transfer activities between November 11 through November 15, 1996. The inspectors noted good communications between the control room, upender operator in containment, upender operator in the spent fuel pool, and manipulator crane operator in containment. The upender operator in containment conscientiously performed his duties using good communication skills and maintained the refueling log up-to-date. The refueling senior reactor operators (SROs) maintained good management oversight and professional demeanor.

The inspectors observed personnel operate the manipulator crane safely and used good communications throughout the operations. They were observed to communicate well with the refueling SRO, the refueling engineer and the health physics technicians. For example, late Wednesday (November 13, 1996) day shift problems were experienced grappling the second fuel cell on the west side of the vessel. Apparently, the cell was slightly bowed and didn't allow grappling using the normal indexing methods. The bridge operators proceeded cautiously to manually position the bridge several times. The refueling engineer and the bridge supervisor were present and deliberated with the refueling SRO on various alternatives. The dayshift bridge personnel suggested rotating the refueling mast to achieve alignment but the refueling procedures did not specifically allow or prohibit this action although the contractors considered this an acceptable practice. The evening bridge crew arrived within a half an hour after the problem occurred and suggested moving the mast cable to achieve alignment with the fuel cell. This was allowed in the refueling vendor procedure (VP)-798, FP-CYW-R19 Refueling Procedure. Operators moved the mast cable and successfully grappled the fuel cell.

On November 12, 1996, the inspectors observed appropriate control by the refueling SRO as the manipulator crane operator bypassed crane limit switches. The limits switches were bypassed during the refueling equipment checks and during the emergency procedure exercise. Both activities were accomplished with the manipulator mast grappled to the "dummy" fuel assembly. The inspectors observed that no other request to bypass any of the trolley, bridge, or hoist limit switches occurred during fuel movement.

The licensee adhered to various procedural and technical specification requirements, based on direct inspector observations in the control room, the spent fuel building and in the containment. The inspectors verified the following requirements; minimum reactor cavity level, minimum spent fuel pool level, source range nuclear instrumentation operability and audible count indication, establishment of communications, residual heat removal operability and minimum flowrate, equipment tag-outs for the reactor coolant pumps and the refueling canal drain piping valves. The equipment was in its proper operation and requirements were adhered to. The health physics coverage and foreign material controls were effective. The foreign material control was maintained as specified in WCM 2.2-5 and the log was maintained up-to-date. The refueling prerequisites, precautions and surveillance requirements were completed as specified in NOP 2.3-5, Refueling Operations.

On November 13, 1996, the inspectors walked down the containment purge system using licensee normal operating procedure (NOP) 2.13-2, "Reactor Containment Atmospheric Control System, attachment 7.1." The inspector's walkdown of the ventilation alignment concluded that the dampers were correctly aligned for containment purge, radiation monitors were operable to measure release rates, and that the flowrate from the purge fans were within the release permit. The inspector walked down the spent fuel cooling system to verify it was aligned as specified in NOP 2.10-1.

On November 14, 1996 the inspectors compared NOP 2.13-5A, "Tracking and Establishing Modified Containment Integrity and Containment Closure," with tag clearance 96-1004. The purpose of the comparison was to validate containment closure was established during core alterations. The inspector noted no discrepancies between the completed NOP 2.13-5A and tag clearance 96-1004. The inspector verified approximately 40% of the tags were properly hung on the components identified in tag clearance 96-1004.

The training records were reviewed for the training conducted to licensed operators and contractors who were hired by the licensee to perform refueling activities. The inspector reviewed the lesson plans, attendance records, and the job performance measures used in the training. The inspector concluded that the records and training material content were acceptable. The inspector noted that the licensee did not have a training program description and implementing procedure for conducting refueling operations and fuel movements that outlined management's expectations for the training of licensed operators and contractor personnel.

Throughout the core offload, the inspector verified that fuel movement was completed in accordance with the sequence specified in the Fuel Handling Data Sheets of FP-CYW-R19. The inspector confirmed that the fuel stored in the pool met the burnup requirements of Technical Specification 4.9.14, based on the completion of SUR 5.3-54 and the independent confirmation of fuel assembly burnup data. The licensee maintained the fuel movement status boards during the core offload. The inspector verified by a sampling review that the status board was accurate and reflected the final location of special nuclear material in the spent fuel pool.

c. <u>Conclusions</u>

The defueling operations observed were safely conducted utilizing good teamwork and communications between all involved. The refueling SROs maintained good management oversight and professional demeanor. Technical specification requirements and procedural controls reviewed were acceptably implemented and adhered to. The training records and training material content were acceptable. The inspector noted that licensee did not have a training program description and implementing procedure for conducting refueling operations and fuel movements that outlined management's expectations for the training of licensed operators and contractor personnel.

O2 Operational Status of Facilities and Equipment

O2.1 Operational Readiness for Defueling (Mode 6) and Core Offload

a. Inspection Scope

The inspection scope was to review the licensee actions to recover from the nitrogen intrusion event and to assure the plant was ready to complete the core offload.

b. Observations and Findings

Following a nitrogen intrusion event in September, 1996, the licensee initiated a series of broad actions to recover from the event and to assure the plant was ready to enter Mode 6 and to begin core offload. The licensee action plan established the following criteria which had to be satisfied prior to proceeding to core offload: (i) both RHR trains were available for service, including the securing of regulatory relief as needed; (ii) the completion of an independent review team (IRT) to investigate and determine the root cause of the major events that challenged reactor safety margins; and, (iii) the completion of appropriate corrective actions identified from the IRT as related to the initiation of core offload. The action plan was subsequently expanded to include the findings and weaknesses noted in NRC Inspection 50-213/96-80, and the recommendations from the Nuclear Safety and Oversight (NSO) group, as described below. The licensee requested the NU Safety Analysis Branch to complete an analysis of the nitrogen intrusion event to assess the adequacy of the available compensatory measures and the potential plant vulnerabilities.

The NSO provided recommendations to line management regarding actions that should be taken to address performance issues prior to proceeding to reactor disassembly and core offload. The recommendations were included in memoranda dated September 20 (CT-NCO-96-004) and September 25 (CY-NSO-96-004 Rev 1), and included the results of the Independent Review Team investigation and the common cause analyses. The recommendations covered the following items: restore both RHR trains to an operable status; review plant systems needed for core offload to provide confidence that systems will function as intended; review the systems needed for Mode 6 to verify that deficiencies are resolved or will not degrade system performance; continue the stop work order in effect to protect key safety functions as the RHR deficiencies were addressed; improve the quality of pre-job briefs; improve the control of outage activities to reduce shutdown risk; increase management coverage of key activities; review and improve operating and maintenance procedures associated with reactor disassembly and core offload; assure the level of controls for reduced inventory conditions are appropriate and increase operator sensitivity to single barrier configurations; address deficiencies in reactor vessel vent and level indications for Mode 5 operations; and address management expectations for operators to seek outside assistance when unexpected results are encountered.

The inspector reviewed the activities by the line and NSO organizations to develop and implement the action plans to address the issues summarized above. The licensee divided the corrective actions into a Mode 6 and Core Offload Checklists, and assigned responsibility to the operations, maintenance, work control, and engineering groups as needed to implement the plan. The inspector monitored the completion of the activities and selected certain actions for independent review and followup. The inspector also attended meetings by the plant operations review committee convened on September 30, October 7, 18, 24, 28, 31 and November 7 to review the status and completion the actions needed proceed with the offload.

The licensee plan addressed the items discussed above as well as other actions necessary to assure operational readiness for refueling. The inspector reviewed the completion of the action plan on a sampling basis. The actions are described below, and were summarized (in part) in a letter to the NRC dated October 23, 1996 (B15938).

(1) Safety Analysis Assessment

The NUSCo Safety Analysis Branch provided the results of its assessment of the September 1 nitrogen intrusion event in a memorandum dated September 25, 1996 (NE-96-SAB-240). The assessment included three aspects of the event: the adequacy of procedure Abnormal Operating Procedure (AOP) 3.2-12, the potential scenarios that could have occurred had other barriers to adequate core cooling failed; and, a simulation of the event using the RELAP5/MOD3 computer model to provide a best estimate of the lowest level reached in the reactor.

Based on an estimated nitrogen in leakage rate of 4 cubic feet per minute, the licensee calculated that about 5000 to 6300 gallons of RCS water was displaced during the nitrogen intrusion event, and the minimum reactor vessel water level was between 31 and 62 inches above the top of the hot leg. The guidance provided to the operators in AOP 3.2-12 would have allowed the operators to successfully mitigate the event had the level decrease continued. This outcome was assured even if the RHR and charging pumps had become air bound. Although core boiling would have occurred, the core would have remained cool through reflux boiling, or natural circulation cooling, until the operators restored forced cooling using an RHR or charging pump. The licensee concluded that the margins to core safety were significantly reduced during the event, and a number of potential conditions which could have lead to core damage were identified had additional degradations occurred. The probability of those outcomes were not quantified due to the absence of the conditions during the event, the lack of quantitative data, and the operator awareness of degraded conditions starting on September 1, 1996.

Although the safety significance of the nitrogen intrusion event was high, there were no actual adverse safety consequences for the plant, plant personnel or the public health and safety.

(2) Core Cooling System Redundancy

The licensee completed repairs to the "B" RHR pump on September 25, 1996 and characterized the defect in the "A" RHR heat exchanger inlet valve, RHR-V791A.

The "B" pump failed due to a combination of original manufacturing defects and a marginal design in the tolerances of internal components in the rotating element. Licensee actions this period addressed those deficiencies on the "B" pump, as well as leakage from the stationary oil baffle ring on September 23. Since some of the same tolerance deficiencies had been corrected on the "A" RHR pump, the licensee concluded that the "A" RHR pump was reliable for core offload and deferred additional work identified as lessons learned from the "B" pump failure until after core offload. The RHR system had two operable pumps as of September 25.

Non-destructive examination of the defect on valve RHR-V791A was completed on September 20 after a radiographic source was lowered into the RHR pit. The licensee's engineering evaluation was that the structural integrity of the valve was not affected by the highly localized through-wall defect, there was no gross wall thinning, and large flaws exceeding the structural limits of ASME Section XI IWC-3000 were likely not present. The licensee submitted a request for relief from the requirements of ASME code Section XI IWC-3000 to allow declaring the valve operable, but degraded with the through-wall defect. The NRC granted the code relief on October 7, 1996. The licensee continued to monitor leakage from the valve using the operators during normal rounds to the RHR pit, as supplemented by the installation of video equipment with continuous readout in the control room. The licensee established criteria to reclose the valve should leakage exceed set limits. RHR-V791A was opened and both trains of RHR were fully operable on October 7, 1996.

(3) Refueling Sequence

Based on an analysis of the September 1 nitrogen bubble event, the licensee recognized that the refueling sequence defined in Refueling Procedure FP-CYW-R19 contained windows of vulnerability where indications of core temperature and vessel level were reduced for periods that were unnecessarily long. The refueling sequences was reviewed and revised to optimize availability of level indication for operators. Specifically, as described in Temporary Procedure Change TPC 96-648, Section 7.1.2 was changed to move the action of disconnecting the temporary core thermocouple and reactor vessel level instrumentation closer to just before the head lift sequence, so as to keep vessel level information available to the operators as long a possible.

(4) Procedure Upgrade and Operator Training

In response to the September 1 event, the licensee established an operation's procedure group to address deficiencies within infrequently used shutdown procedures. The group consisted of four senior reactor operators, two reactors operators, support from system engineers, and one outside contractor. The licensee revised in excess of twenty-four (24) procedures concerning shutdown operations. The type of procedures involved included operations department instructions, normal operating procedures, annunciator procedures, abnormal operating procedures, and work control manual procedures. Attachment A of this report lists the revised procedures that were reviewed by the inspector. Major changes included: operator logging of all reactor coolant system inventory changes, guidance on when pre-evolution briefings should occur, various methods to make-up to the reactor coolant system, awareness of shutdown risk, annunciator actions in response to high/low cavity level alarms, methods of adding make-up to the reactor coolant system during a postulated cavity leak or reactor coolant leak, and additional requirements for operator log entries. The above procedures were prepared in October, 1996. The level of detail and quality of the procedures improved from prior to September 1, 1996. Operator training on the revised procedures was observed by the inspector, as documented in report detail O5.2.

(5) System Readiness Reviews

The system engineers conducted reviews of systems needed to support operation in Mode 6 to assure the plant was ready for core offload. The reviews included a walkdown of the systems and a review of outstanding trouble and deficiency reports to assure items impacting system operation were addressed. The purpose of the review was to assure that no significant material conditions existed that would affect the safe conduct of core offload.

The licensee identified and corrected several items in the spent fuel pool cooling system, as described in section (6) below. Several other significant deficiencies were identified and corrected, including problems in the boric acid heat trace system (see LER 96-27 and Section E8.4 below) and inadequate spent fuel building ventilation (see LER 96-25 and Section M1.2 below). The licensee also addressed the uncertainty calculation for instrument loops needed in Mode 6 and the condition of the refueling equipment. Several material condition deficiencies were identified regarding leaky valves in the CVCS system. The licensee elected to continue to use administrative means to address the valve leakage, and to defer maintenance to address valve leakage until after the core was offloaded. The deferral of the valve work was deemed necessary to minimize the time in a higher risk condition (by offloading the core), and then conduct the valve work with the reactor defueled.

(6) Spent Fuel Pool Material Deficiencies

Several actions were taken to address deficient material conditions in the spent fuel pool (SFP) cooling system. The areas addressed by the licensee prior to core offload included: replacement of the check valves on the discharge of the SFP cooling pumps; replacement of both SFP cooling pump motor breakers due to potential hot spots; identification and repair of a linear indication on the service water (SW) supply piping to the SFP heat exchangers; the inspection and repair as necessary of pipe support attachments welded to the SW pipes, starting from the intake structure up to the SFP heat exchangers; inspection and repair of degraded welds on the SW supply and return piping at the SFP heat exchangers; inspection and cleaning of valve SW-MOV-837A to assure it was leak tight; and, the replacement of valve SW-239 on the Adams filter supply to the SFP heat exchanger, after the valve disc was found separated from the stem. See Section M2.2 for further NRC review of this area.

(7) Operations Performance

The licensee took several actions to correct deficiencies in operations performance, as characterized by low standards in procedure use and adequacy, a lack of a questioning attitude and inadequate pre-job briefs. The action included: the appointment of a new Operations Manager; the issuance of several new and or revised procedures; and, the promulgation of an increased emphasis on management standards and expectations through revised procedures and management meetings with plant workers. A new department instruction was prepared for pre-evolution briefings, which provided a detailed checkoff of the items to be covered during a briefing. The department instruction for "conduct of operations (ODI-1)" was revised to emphasize expectations regarding the need for a questioning attitude, and the expectation that assistance from outside the duty shift crew be obtained when offnormal conditions exist.

The licensee also issued revised department instructions for monitoring RCS inventory in Modes 5 and 6 (ODI 190). Finally, the licensee increased management oversight and control of outage activities by revising WCM 1.2-9 to require that significant delays and work stoppages be processed as an outage schedule change. The schedule changes would be reviewed for impact on shutdown risk and would be approved by the Unit Director.

(8) Management Oversight

The licensee took steps to better define management expectations to the work force in a series of memoranda and meetings. In particular, management expectations regarding several station activities were defined in a memorandum form the Unit Director dated October 7, 1996, covering the following topics: the conduct of physical work, work planning, pre-job briefs, supervisory oversight, job completeness, feedback of lessons learned, and stopping work when help is needed. The licensee increased the presence of upper management onsite during back shift hours and for the following key activities: drain down to the refueling reference level, lift of the reactor head, filling the reactor cavity, removing the upper internals, and starting core offload. The back shift coverage was provided by the Operations Manager, the Work Services Director and the Unit Director. The licensee also assigned mentors to each operating shift to monitor for compliance with the new standard for the conduct of operations. The shift mentors were experienced operations personnel from other nuclear plants. The mentors were on shift from the start of the vessel drain down to the completion of the core offload.

(9) Awareness of Shutdown Risk

The licensee issued a revised department instructions for monitoring shutdown risk (ODI 191). The purpose of ODI 191 was to promulgate expectations and to increase operator awareness of five key safety functions, procedural controls and operational philosophies designed to minimize shutdown risk.

The inspector noted that the implementation of the above measures had mixed success. Despite the renewed emphasis on monitoring key functions and shutdown risk, an event occurred on November 2 while the vessel was drained to the refueling reference level in which work on the critical path for defueling was interrupted for about 15 hours following a personnel contamination event inside the containment. The delays occurred at the time of high shutdown risk, and were not fully appreciated nor investigated by plant personnel, and were not communicated to upper management in a timely manner. Plant operators and other outage personnel demonstrated a poor sensitivity to the time spent in a high risk condition. This matter is addressed further in Inspection 96-12.

c. Conclusions

Licensee actions were generally thorough to recover from the nitrogen intrusion event, restore redundancy to core cooling functions and to assure the facility and plant staff were ready to enter Mode 6 and complete the core offload sequence. Corrective actions to address plant material conditions and plant staff performance deficiencies were appropriate. Subsequent routine inspections will review the adequacy of licensee actions to improve worker performance and minimize shutdown risk.

O3 Operations Procedures and Documentation

O3.1 Revision of Procedures for Shutdown Operations (EEI 96-11-01)

a. Inspection Scope

The inspection scope was to evaluate the completeness of procedure changes that addressed deficiencies in procedures used for shutdown operations. The deficiencies involved:

- improper use of an administrative control procedure (ACP) 1.2-5.3, Evaluations of Activities/Evolutions Not Controlled by Procedure, to vent the charging system and drain the reactor coolant system

- lack of guidance on preserving reactor coolant loop overpressure protection when isolated

- identification of station nitrogen usage

Additionally, the inspector reviewed the quality of procedural changes.

b. Observations and Findings

In response to the events in early September, 1996, the licensee established an operation's procedure group to address deficiencies with infrequently used shutdown procedures. The group consisted of four senior reactor operators, two reactors operators, support from system engineers, and one outside contractor.

The inspector verified that the licensee deleted the use of ACP 1.2-5.3 on October 23, 1996. The licensee developed and approved two NOPs that were previously developed using the guidance of ACP 1.2-5.3. The two procedures were NOP 2.6-12, "Draining the Reactor Coolant System in Modes 5 and 6" and NOP 2.6-9B, "Recirculation of 1B Charging Pump on the Refueling Water Storage Tank." The procedures provided adequate detail and guidance to accomplish their intended objective.

The licensee implemented procedural enhancement in NOP 2.6-12, "Draining the Reactor Coolant System (RCS) in Modes 5 and 6" and NOP 2.4-7, "Return of a Loop to Service with the Plant Shutdown," to provided guidance during a draindown to preserve loop overpressure protection (isolated RCS loop) with the drain header aligned to the loop and placing the drain header relief valve in-service.

Operations Department Instruction (ODI)-190, RCS Inventory in Modes 5 and 6, required operators to log on a shiftly basis station nitrogen use, and to make management aware of an unexpected change in its trend. The licensee revised an additional twenty-four (24) procedures concerning shutdown operations. The type of procedures involved included operations department instructions, normal operating procedures, annunciator procedures, abnormal operating procedures, and work control manual procedures. Attachment A to this report lists the procedures that were reviewed by the inspector.

The licensee identified during the procedural upgrades that no procedural guidance existed for a fuel handling accident. On October 24, 1996, the licensee approved AOP 3.2-63, "Fuel Handling Accident." Failure to have a procedure providing guidance during a postulated fuel handling accident is a violation of technical specification (TS) 6.8.1. TS 6.8.1 requires that written procedures shall be established and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, (February, 1978). Regulatory Guide 1.33 Appendix A item 6.X lists procedures for irradiated fuel damage while refueling. This is an apparent violation **(EEI 96-11-01)**. The lack of procedural guidance is significant in that this event is analyzed in the Updated Final Safety Analysis Report, and emergency declarations are based upon a dropped assembly. The inspector noted that the licensee experienced a dropped fuel assembly on February 26, 1986. The licensee corrective actions were to improve the foreign material exclusion procedures since the apparent cause was a foreign object. Specifically, a foreign object caused the fuel alignment pin to be bent resulting in the fuel assembly coming up with the vessel's upper internal package. No corrective actions addressed procedural guidance to mitigate a dropped fuel assembly.

c. Conclusions

The upgrade of various operating procedures was appropriate. The inspector noted improved detail and quality in the procedures revised when compared to the quality of procedures prior to September 1, 1996. A violation of TS 6.8.1 was identified whereas the licensee did not have a procedure for fuel handling accident as recommended in Regulatory Guide 1.33.

O4 Operator Knowledge and Performance

O4.1 Reactor Coolant System Inventory Diversion (EEI 96-11-02)

a. Inspection Scope

The inspector evaluated operator performance during a makeup to the refueling water storage tank (RWST) on September 26, 1996. Operators initiated a makeup of approximately 15,020 gallons to the RWST using the guidance in NOP 2.6-3, "Blended Makeup to RWST." The purpose of the RWST makeup was to prepare to fill the reactor cavity. The RWST is the primary source of borated water for the reactor cavity.

b. Observations and Findings

On September 26, 1996, during a makeup to the RWST, operators noted a diversion of approximately 600 gallons or 4% of the total makeup inadvertently sent into the reactor coolant system (RCS). The apparent cause was leak-by through a shut manual valve (BA-V-367). Valve BA-V-367 is a 2 inch manual globe valve in the piping system between the recycled pure water storage tank (RPWST) and the suction of the charging pumps. In order to have the makeup water enter into the RCS, BA-V-367 and charging flow control valve CH-FCV-110 needed to leak by.

Procedure NOP 2.6-3 6.1.1 required a valve lineup be performed if the dilution water supply is aligned from the RPWST. The operators did not perform this step, yet the dilution water supply was from the RPWST. This valve alignment would have verified that BA-V-367 was closed.

The operators did not aggressively pursue a decrease in RCS boron from 2305 part per million (ppm) to 2288 ppm after the makeup to the RWST. Operators requested a second boron sample from chemistry; however, they did not identify the source of the diverted water. The potential existed for pure water to be in the charging system that was credited as the emergency boration flowpath. On October 1, 1996, the licensee sampled the flow paths. The boron concentration was between 1817 and 1825 ppm less that the RCS, which confirmed the existence of a dilution into the RCS. The boron concentration was still greater than the required shutdown margin concentration of approximately 850 ppm.

The inspector reviewed the maintenance history for valve BA-V-367. The valve was not subjected to any routine preventive maintenance activity, and the only recorded corrective maintenance activity was performed in 1989 (Authorized Work Order 89-10487) to adjust the valve packing due to leakage.

Prior to this event, five adverse condition reports (ACRs) were prepared in September, 1996, identifying various chemical and volume control system valve leakage. On September 3, 1996, a similar event occurred whereas operators suspected that a boric acid flow control valve (BA-FCV-112C) was leaking through to the charging header during a makeup to the RWST. The difference between the two events was the makeup flowpath, and that operators secured from the makeup on September 3, 1996, when they noted an unexpected rise in pressurizer level of 1%. Additionally, on September 18, 1996 the licensee documented in ACR 96-1062 that boric acid and pure water valves were not designed as zero leakage thus creating the possibility of dilutions into the RCS. The inspector concluded that based upon the recent events, licensee corrective actions to preclude the event on September 26, 1996 were ineffective in that compensatory measures to preclude unintended leakage into the RCS were not taken. Each of the corrective actions proposed from the five related ACRs were to trouble report the suspected leaking valve, and schedule future repairs. This is considered a violation of 10 CFR 50 Appendix B criterion XVI **(EEI 96-11-02)**.

c. Conclusions

The licensee corrective actions in response to recent valves that leak-by in the boric acid and pure water systems were ineffective in preventing the event on September 26, 1996. Operations personnel did not aggressively respond to either terminating the make-up to the RWST with known RCS inventory changes, or the potential of having diluted water in the credited emergency boration flowpath. Operators did not adhere to the NOP 2.6-3 that would have required a valve alignment check of valve BA-V-367. No preventive maintenance program existed for the valve (BA-V-367) that was suspected of leaking-by.

O4.2 Response to Low Cavity Level Alarm

a. Inspection Scope

The inspection scope was to observe and evaluate operator actions in response to a low cavity level alarm on October 24, 1996.

b. Observations and Findings

On October 24, 1996, the inspector observed operator actions in response to a slow decrease in RCS inventory (pressurizer level decrease of 1%) over approximately 3.5 hours. The inventory reduction was confirmed by a reactor cavity low level alarm. The operator quantified the rate of inventory decrease at approximately 0.44 gallons per minute (gpm), and implemented the applicable procedures; AOP 3.2-31A," Reactor Coolant System/Refueling Cavity Leak (Modes 5 and 6)," and Annunciator Procedure (ANN) 4.24-2, "Cavity Low Level." The operators did not identify any leakage from the RCS, or the RHR system. At the time of RCS inventory reduction, the operators noted an increase in the aerated drains tank level. Conversations between operations personnel and the on-shift chemistry technician concluded that two RHR boron samples were drawn at the start and the end of the RCS inventory reduction. The first sample at approximately 8:00 a.m., equated to the start of the decrease in reactor coolant system inventory. A second sample taken at approximately 11:30 a.m., at the end of the reduction in RCS inventory. The operators attributed the decrease to a RHR sample valve that was leaking by from the RHR system into the aerated drains tank. The valve was trouble reported.

c. Conclusions

On October 24, 1996, the operators noted RCS inventory changes and implemented the applicable procedures.

O5 Operator Training and Qualification

O5.1 Cavity Seal Leak Training

a. Inspection Scope

On November 12, 1996, the inspector observed the refueling crane operators perform exercises involving emergency operating procedure (EOP) 3.1-48, "Loss of Refueling Cavity Inventory." The inspection scope was to evaluate operator adherence to the EOP action steps, and to verify that the actions were accomplished within the acceptance criteria.

b. Observations and Findings

The contractor refueling crane operators displayed adequate knowledge of the procedure and its implementation. The operators adhered to the applicable steps within EOP 3.1-48 Attachments A and B for both the manipulator crane operator and the upender operator. The scenario was to take a mock fuel assembly from above the core to its safe location within the fuel transfer canal, place the transfer cart into containment, close the spent fuel pool sluice gate, and simulate closing the manual transfer canal valve inside containment.

The evolution was timed to verify that the required actions could be taken in less time than assumed in the analysis for the time it would take to drain the cavity in the event of a seal failure. The licensee had shown that the cavity could drain in about 20 minutes based on past operating events at Haddam Neck, with a seal design more vulnerable than the existing seal. The acceptance criteria for EOP 3.1-48 was established at half that time, or 10 minutes.

During establishment of initial conditions, the inspector observed that one of the manipulator crane operators lowered the mock fuel assembly on top of the core, whereas the initial condition for the exercise stated within two feet from the top of the core. In discussions with the operator, the inspector learned that he was not familiar with the top of core location on the Z-Z tape (vertical orientation). The refueling SRO was notified by the inspector and the manipulator crane operator raised the assembly above the core. The inspector confirmed that the Z-Z tape was appropriately marked for the top of core as part of the final manipulator crane checkouts. The final crane checkouts occurred after the training exercise. No adverse consequence was observed during this evolution.

The completion of the training was verified as being appropriately documented in vendor procedure (VP)-798, FP-CYW-R19 Refueling Procedure.

c. Conclusions

The EOP exercise on a postulated cavity seal leak was successfully implemented by the refueling crane operators.

O5.2 Operator Training on Procedural Revisions

a. Inspection Scope

The scope of the inspection was to observe and evaluate the quality of classroom training provided to operators. The training was on the procedural changes used during a shutdown condition.

b. Observations and Findings

The inspector attended operator training on September 27, 1996 for the reactor cavity level indication system (CLIS), and on October 22, 1996 for the significant changes to the operations procedures for shutdown operations.

The training provided to the operators on the CLIS focused on indicator limitations and system errors in response to excessive RCS gas flowrates. The training also identified the purpose of vacuum compensation, and the lesson-learned during the ingress of nitrogen into the RCS in late August, 1996.

The training on October 22, 1996 provided an overview of sixteen (16) new or significantly revised procedures, accomplished an "in-plant" job performance measure to align the purification system for RCS makeup, and simulated a pre-evolution briefing on RCS draindown. At the closure of the training, a written exam was provided to operators. The training duration was approximately eight hours. The trainer provided a copy of each procedure, went over the basis for each of the prerequisites and precautions for the new procedures, and provided the basis for each procedure step change. During the classroom instruction, exercises were performed to classify the emergency level for a dropped fuel assembly, and to calculate the expected volumes of inventory during either draindown or makeup to the RCS.

The operations manager and training instructor provided a critique on the operations crew pre-evolution briefing for a RCS draindown from 50% pressurizer level to eleven inches below the reactor vessel flange. The critique of the briefing focused on the need for communication repeat backs, improvements for the unit supervisor (US) to state all procedure prerequisite steps, and the need to request engineering support for contingency actions.

c. Conclusions

The training to operators appropriately focused on the details and purpose for the significant changes to operations shutdown procedures.

O8 Miscellaneous Matters

O8.1 1996 INPO Evaluation

The last evaluation by the Institute of Nuclear Power Operations (INPO) was performed in May, 1996, and the report was issued in September and made available for NRC review on October 3, 1996. In overview, the assessment found several notable practices and accomplishments, including a high level of pride in the plant, strong plant focus of the station work groups that resulted in good teamwork, effective valve maintenance, a concerted effort to upgrade equipment in the areas of control rod position indication and radiation monitoring, the use of nonintrusive acoustic testing.

Several areas for improvement were also noted, such as: precursors to reactivity control events, maintenance conducted outside the AWO job scope, engineering evaluations that are not thorough, a need to be more aggressive in ALARA, and, ineffective use of operating experience, work observations, self-assessments and risk assessment tools. The inspector noted that the INPO findings did not identify any safety significant findings not already known to the NRC.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

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

- AWO 96-7718 Cavity Seal Hatch Leak Test
- AWO 96-6787 RHR-V791A Nondestructive Examination
- AWO 96-7552 B RHR Pump Thrust End Stationary Oil Baffle
- AWO 96-8734 Ultrasonic Service Water Flow Measurements on the Spent Fuel Pool Return Header

- AWO 96-8540 SFP Cooling Piping Repair

- AWO 96-9229 Reactor Cavity Seal Leak

b. Observations and Findings

The above maintenance activities were adequately implemented. Except as discussed in Section M2 below, the inspector had no further comments in this area.

M1.2 Observation of Surveillance Activities (EEI 96-11-03)

a. Inspection Scope

The inspectors observed the following surveillance activities:

• SUR 5.1-159B	Boron Injection Flowpath Verification and Metering Pump Test
• SUR 5.7-162	In-Place Testing of the Spent Fuel Building Filters
• Special Test 11.7-200	Underwater Reactor Cavity Hatch Seal Troubleshooting
• SUR 5.3-54	Burnup Requirements for Spent Fuel Pool Storage
• SUR 5.1-104A	Boric Acid Flowpath Operability Test
• ENG 1.7-102	SFPC Heat Exchanger and Pump Test

Except as noted below, the inspector had no further comments in this area.

b. Observations and Findings

Ventilation Testing

On September 27, 1996, the system engineer documented a failed air flow while performing surveillance procedure (SUR) 5.7-162. SUR 5.7-162 implements technical specification (TS) surveillance 4.9.12.a.3. The minimum TS spent fuel building air flow through the charcoal filters is 3,600 cubic feet per minute (cfm) and the measured air flow on September 27, 1996 was 1,990 cfm. The spent fuel building ventilation system is required to be operable during movement of fuel in the spent fuel building. The ventilation system ensures that all radioactive material released from an irradiated fuel assembly will be filtered through the charcoal absorber prior to discharge to the atmosphere.

The licensee learned through troubleshooting efforts between September 28 - October 2, 1996 that the flowrate through the spent fuel building ventilation system was dependent on the configuration of the primary auxiliary building (PAB) ventilation system. Specifically, spent fuel building ventilation system airflow changes from acceptable to unacceptable depending on the number of PAB exhaust fans in operation, amount of supply air in the PAB system, and if containment purge is in service or not. The primary reason for interaction of the two ventilation systems is that both are connected to the exhaust ducting prior to reaching the main stack. The proper flow was obtained by adjusting the fan discharge damper.

The surveillance procedure did not require a verification of the PAB exhaust ventilation system alignment. The inspector reviewed historical surveillance results and concluded that the last three tests were performed within the acceptance criteria of the TS, however they were performed during power operation with no containment purge in service. Specifically, the surveillance was performed on January 14, 1993 (refueling outage was between May, 1993 - July 20, 1993), and on July 13, 1994 (refueling outage began January 28, 1995 - April 19, 1995), and February 13, 1996 (outage began on July 22, 1996). During refueling conditions, containment purge supply and exhaust valves must be operable in accordance with TS 3.9.9. and one of the two PAB exhaust fans are in operation for containment purge. The failure to have an adequate procedure to verify that the spent fuel building ventilation system was able to perform its intended function is considered a violation of TS 6.8.1 **(EEI 96-11-03)**. Even though the testing performed in September, 1996 was prior to the system being required to be operable, the results indicate that the airflow was less than required based upon the affects of PAB ventilation, and when the historical surveillance were performed.

On October 4, 1996 the licensee determined that this surveillance failure was a condition prohibited by technical specifications. Licensee event report (LER) 96-025 dated October 24, 1996 documented this event. An apparent cause of the surveillance failure was inadequate knowledge of testing and engineering personnel regarding the PAB ventilation alignment changes between power operation and refueling operations, and the affects on the flowrates through the spent fuel pool building ventilation system.

The design basis of the spent fuel pool ventilation system was evaluated in systematic evaluation program (SEP) Topic XV-20 and referenced in Updated Final Safety Analysis Report (UFSAR) section 15.5.2.2. The licensee concluded in SEP Topic XV-20 that spent fuel building ventilation was not required to be in operation during a fuel handling accident to maintain offsite doses less than 10 CFR 100 limits; however, it was recognized that the normal operating procedure requires that it be in service with the exhaust aligned to the charcoal filter when fuel is being moved. Notwithstanding, the analysis in SEP Topic XV-20, technical specification 3.9.12 requires the system to be operable during movement of fuel within the spent fuel building at an airflow of 4,000 cfm +/-10%. UFSAR section 15.5.2.2 states that the fuel building ventilation system and its associated charcoal filters will be in operation during fuel handling.

Licensee corrective actions were to administratively control the position of the PAB ventilation damper (specifically dilution damper setting), and control the SFB exhaust fan discharge damper position. The surveillance was re-performed successfully with containment purge in-service prior to fuel movement.

The inspector verified that SUR 5.7-162 appropriately implemented ASME/ANSI N510-1980 ,Testing of Nuclear Air-Cleaning Systems, Section 8, Airflow Capacity and Distribution Tests guidance. The industry standard was reference in technical specification basis 3.9.12.

Boron Flow Path

On October 18, 1996 the inspector observed a nuclear system operator (NSO) implement SUR 5.1-159B, Boron Injection Path Valve Lineup and Metering Pump Test (Shutdown Modes 5 and 6). The activity on October 18, 1996 was performed with appropriate procedural compliance and a good pre-evolution briefing.

Seal Hatch Leak Test

On November 8, 1996, the inspector observed licensee personnel implement special test (ST) 11.7-200. The procedure was to confirm the o-ring integrity on the cavity seal hatches. An air pressure test between the two o-rings on the hatches was performed prior to flooding of the reactor cavity. It was performed satisfactorily on October 2, 1996; however, due to leakage from the cavity tell-tail drains on November 5, 1996, the licensee opted to re-verify the hatch integrity with the refueling cavity full of water. ST 11.7-200 was developed to accomplish this diving evolution.

The pre-evolution briefing was led by the system engineer with operations management, maintenance personnel, contractor divers, health physics, and radwaste technicians in attendance. The briefing was detailed. The health physics technicians led a briefing with the divers on the radiological controls during the dive using radiation protection manual (RPM) 2.5-7, Diving Evolutions, for guidance. The health physics briefing focused on low dose areas, importance of controls of cavity entrance and exits, and the process for tool removal. The inspector noted that dose to the divers was remotely displayed and during the performance of ST 11.7-200 and continuously monitored by health physics technicians. The inspector observed the reactor operator at the cavity tell tail drains record the cavity seal leak rates prior to, during, and after each of the pressure tests on the cavity hatches. No change in cavity seal leak rates was observed. The inspector noted that the operator displayed good knowledge of radiological conditions by remaining in the designated low dose areas when leak rates were not requested.

The performance of ST 11.7-200 did not identify that the cavity seal hatches as the source of leakage. Notwithstanding, the inspector noted appropriate health physics support and good control by the system engineer during implementation of the procedure.

c. Conclusions

The surveillance test to verify operability of the spent fuel building ventilation system had inadequate controls to ensure that acceptable airflow results were obtained. This surveillance inadequacy resulted in a historical violation of the technical specifications. The licensee reported this event as a condition prohibited by technical specifications. The method of air flow testing was consistent with industry standard ASME/ANSI N510-1980 as depicted in the technical specification basis and surveillance requirements. The inspector noted appropriate health physics support during the implementation of ST 11.7-200.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 "B" Residual Heat Removal Pump Repairs Following Overhaul

a. Inspection Scope

On Saturday September 15, 1996, while running the "B" Residual Heat Removal (RHR) pump for 48 hours following pump repairs discussed previously, operators noticed oil leaking from the stationary oil baffle seal on the motor end of the pump. Following investigation the oil baffle seal was replaced with a new seal. However, once the pump was started, within seconds operators observed smoke and unexpected noise. Once the pump was secured, inspection revealed the oil baffle was damaged and had welded to the pump shaft. The inspectors reviewed maintenance procedures, safety evaluations, root cause determination and test procedures, and interviewed maintenance, test and operations personnel to determine causes and the adequacy of corrective actions.

b. Observations and Findings

Following the "B" RHR pump shaft seizure on September 1, 1996, Connecticut Yankee (CY), determined the cause of the failure and performed repairs to the pump. As a retest, the pump was started and run for approximately 48 hours. At that time, operators noticed oil leaking from the stationary oil baffle seal, which is located on the motor side of the pump housing. The pump was secured and inspected. It was determined that the oil baffle seal had rotated, either because of vibration or contact with the pump shaft. As a result of the baffle seal rotation, the drain hole, which directs the oil back into the casing also rotated out of the "6 o'clock" position. With the drain hole out of the required position, oil traveled down the shaft and was observed by the operator.

The oil baffle seal was designed to be secured into the bearing housing cover with an interference fit. As a result, the measurements and manufacturing tolerances of the baffle are critical to ensure an adequate fit so that the baffle does not come in contact with the pump shaft.

A new baffle was ordered and received onsite. However, when installed it was also loose and did not have the required interference fit. With the vendor, Ingersol Dressor Pumps (IDP) approval, the baffle seal was "punch pricked" and locktite was used to secure it to the pump housing cover. Because of the tight clearance requirements, the clearance between the baffle seal and the shaft was also questioned by CY personnel. On September 21, 1996, during a telephone conversation, the vendor told CY that the clearance should be between 4 and 11 mils total diametrical clearance. That is 2 to 5.5 mils radial clearance between the shaft and the baffle seal.

As a result, CY determined to use a 3.5 mil radial clearance (7 mil diagonal) and milled the baffle to this specification prior to installation. The runout, or flex, of the shaft was measured to be approximately 2 mils total. This should have given the baffle approximately 5 mils of diametrical clearance or 2.5 mil radial clearance. When the pump was started on September 21, 1996, operators immediately observed smoke and noise coming from the area of the oil baffle seal. The pump was secured and operators observed that the baffle had welded itself to the shaft and rotated with the shaft.

Following partial disassembly and inspection of the pump shaft, oil baffle seal and thrust housing, CY determined that the clearances specified by IDP during the September 21, 1996 telephone conversation had been inaccurate and that the baffle had made contact with the shaft. As a result of the combined tolerances allowed on components of the pump, the clearance specified between the baffle and the shaft was too small to ensure adequate clearance.

As a result of the failure the vendor performed a more detailed review of the specifications for the oil baffle seal. This review indicated that the nominal clearance required between the baffle and the housing should be a diametrical total of 18 mils. The 4-11 mils specified earlier was in error and was based on a review of the tolerances stacking up on the pump components. At the time of the September 21, 1996 call, IDP had been reluctant to give CY the actual pump drawings because they included proprietary information. The lack of ability to review the actual drawing specifications resulted in CY relying completely on IDP for technical information regarding pump measurement specifications.

Because of problems with ordering the correct sized baffle seal, CY decided to fabricate a baffle seal onsite using actual drawings obtained from the pump vendor representative and measurements of the previous baffles. The new baffle was fabricated such that an interference fit was used and the baffle was shrunk fit into the housing.

On September 24, 1996, the Plant Operating Review Committee (PORC) reviewed and approved of the repair and retesting procedures. On September 24, 1996, the "B" RHR pump was started. However, low discharge pressures and low running amps indicated that the pump was air bound. Difficulty in venting the RHR pumps has been experienced in the past. As a result of the pump piping arrangement, air becomes trapped in the discharge and suction piping of the pump. Once the pump was started with air in the piping, and the "A" RHR pump running, the "B" RHR pump was not able to generate a high enough discharge pressure to open the downstream check valve, which was at RHR header pressure of over 118 psig. Once "B" RHR pump discharge pressure exceeds the RHR header pressure, the check valve can open and sweep any remaining air out of the pump.

As a result of the test failure, CY developed a second test. This test opened a heat exchanger bypass valve which raised header flow and lowered header pressure. The procedure "B" RHR Pump Startup & Troubleshooting test, ST11.7-199 Rev. 1, also allowed the pump to be vented during the run and allowed repeating the run three times to ensure that the pump was adequately vented. At approximately 9:00 p.m. on September 25, 1996, the pump was run satisfactorily and declared operable.

c. Conclusions

The RHR pump failures due to rotation of the baffle were caused by inadequate sizing and spacing of the oil baffle seal. The lack of vendor drawings was a contributor to the inadequate corrective actions to resolve the problem.

M2.2 SFP Service Water System (SWS) Supply Line Inspection

a. Inspection Scope

The inspector reviewed the reported findings by the licensee of spent fuel pool (SFP) SWS supply line indications during the Inservice Inspection (ISI) of five welded pipe supports. The review included the location of the reported indications, the description and nondestructive techniques used to characterize the indications, the evaluation of the SWS supply line operability, and the corrective action taken to preclude failure of the SFP SWS supply line piping.

b. Observations and Findings

Apparent Pipe Crack

As part of the 10-year ISI visual inspection (VT) of hanger-to-pipe welds of the SWS, a Level II licensee inspector noted cracked paint in the region adjacent to the hanger support WS-2028 pipe plate weld. The licensee inspector performed magnetic particle testing (MT) of the pipe surface and found an indication running in an axial direction for 29.75 inches into the Plant Auxiliaries Building (PAB) South Wall through which the pipe passed. The licensee further performed ultrasonic tests (UT) of the crack and reported radial depths of .206 to .235 inches at intervals of 2 inches. Since the nominal thickness of the 6-inch pipe was .253 inches, the indication bode a serious effect on pipe structural integrity. Because of the characteristics of the UT reading, the licensee believed that the indication depth reading may have been affected by an irregular inner pipe surface. Two Level III

NDE technicians re-examined the UT test results and found depths no greater than .065 inches. The Level III technicians believed the defect was typical of a shallow "pipe lap" present in the manufactured pipe material. The indication extended through the wall and ended at a pipe elbow circumferential weld on the other side of the wall.

A 52-inch sample of the SFP SWS supply line containing the defect was sent to the Materials Testing Laboratory of Northeast Nuclear Energy for flaw characterization. An area 40 inches in length revealed a linear, but intermittent indication. Two significant indications were located 2.25 inches from the WS-2028 pipe support pad weld, and a third was located 1 inch from the circumferential pipe weld at the pipe elbow beyond the PAB South Wall. The NRC inspector examined etched photomicrographs (100X and 150X) from a sample slice containing the defect. The photomicrographs revealed defects 7 mils and 4 mils in depth. The etched microstructure of the unaffected pipe was typical of A53 carbon steel, with an equal mixture of ferrite and pearlite. The indication opening of .003 inches was filled with a decarburized matrix with oxide inclusions. The defect morphology indicated that the defects were "pipe laps"probably existing after manufacture. These were believed by the licensee not to be caused by any service-induced loading.

In order to ascertain the qualification of the inspector reporting the initial defect depth, the inspector reviewed the NDE inspector's qualifications and found them to be consistent with requirements of Level II for VT, MT, and UT. The UT inspectors re-interpreting the defect depth UT tests were both Level III in UT.

The licensee evaluated the pipe lap defect to determine the possible effect on operability of the pipe under the anticipated operating conditions, including design, thermal, and seismic loading. For the initially large depths (exceeding .200 inches) the licensee determined that the pipe was inoperable. Subsequently, the pipe was replaced. Subsequent evaluation of the operability of the pipe with "pipe laps" shows that the depth, directionality, and morphology of the flaw detracts negligibly from the ability of the pipe to sustain such loading. The wall thickness reduction, and increased stress resulting therefrom, was negligible. The engineering evaluation was provided in memorandum dated October 22, 1996 (CES-96-325).

Following the initial pipe lap indication finding, the licensee performed MT examinations of the pipe at all 32 SFP SWS pipe supports. At these locations, five non-conformance reports (NCRs) were written. The defects at these locations were found to be shallow "pipe lap" indications and were removed using light buffing, or "flapping" tools.

The inspector requested the original material certifications for review. The licensee could not produce them for examination. There was much of this Class 3 piping in the service water system, and it was believed that any specific piece of pipe material could be identified only from a certified material test report (CMTR) from a batch of piping. In lieu of providing the original CMTR, the licensee arranged for an independent contractor (Dirats Laboratories) to test a sample of the pipe material containing the defect. The results of the test show that the sample was consistent with the ASTM Standard Specification for A-53 Type S seamless pipe, Grade B.

The licensee reviewed the indication findings, the results of the expanded inspection of pipes at the supports, the results of VT, MT, and UT, and concluded that the piping defects resulted from the manufacturing process, and not from any applied loading to the pipe. The licensee concluded that the indications were not of a nature to detract from the ability of the pipe to perform its intended function. On this basis, the licensee believes replacement of any sections of SFP SWS supply line pipe will be necessary only if discovered defects exceed the magnitude permitted by Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code.

Other Material Deficiencies

The licensee expanded the review of SW piping and evaluation of potential defects to assure the SFPCS was acceptable for core offload. The licensee identified flaws in two tee-to-pipe welds in the service water return line from the SFP heat exchangers. The licensee established a flood watch until repairs were done. The affected pipe tee was replaced during an outage of the SW supply to the heat exchangers. Additionally, the licensee replaced a tee on the heat exchanger supply line which had a known defect that was being tracked under the SW corrosion monitoring program (and had been previously found to be acceptable until the Spring of 1997). The licensee replaced the supply side tee as well. The SW supply to the SFPCS was restored to normal on October 30, 1996.

c. Conclusions

The licensee satisfactorily evaluated the safety significance of the findings of "pipe lap" defects in the SFP SWS supply pipe. The use of expanded inspection of all SFP SWS supply pipe at the support hangers, the metallurgical characterization of the defect, the NDE examinations of the defect, the analytic evaluation of the defect, and the corrective action taken was conservative and consistent with good engineering practice. Actions to address other material deficiencies in the SFPCS prior to core offload were appropriate.

M8 Previous Open Items

M8.1 (Closed) IFI 95-02-03, Followup Refuel Equipment Failures

This item was last reviewed in Inspection 96-01 and remained open pending NRC review of licensee actions to upgrade and maintain refueling equipment. The licensee completed several actions to improve or upgrade the refueling equipment prior to the final core offload. The actions and plans in this area were summarized in a engineering memorandum dated September 30, 1996 (CY-TS-96-462), and included: implementing PDCR 1575 to upgrade the fuel assembly upender; checkout of new fuel handling tools and the transfer cart; replacing the cable on the new fuel elevator; checkout of the sluice gate operation; performing preventive maintenance and load testing of the manipulator crane; performing preventive maintenance on the polar and spent fuel building cranes; and, revising the refueling procedures. Finally, the licensee identified a new fuel handling accident involving the dropping of a fuel bundle in the pool from the surface of the water (ACR 96-278). This item needed to resolved prior to placing the new fuel into the spent fuel pool. However, this evolution was never completed after the joint owners of Haddam Neck announced on October 9 that the permanent shutdown of the plant was likely. The listed corrective actions were completed as necessary prior to the core offload. This item is closed.

M8.2 (Closed) URI 96-04-01, Investigation of May 23 Spent Fuel Event

This item concerned the completion of the licensee's review of an event in May, 1996 in which a fuel bundle became suspended on top of the fuel racks. The licensee identified personnel performance issues regarding the overriding of interlocks while inserting the bundle on May 23, and the need for a tool to guide insertion of fuel bundles in the new racks. A funnel type guide tool was successfully used for the core offload in November, 1996. The inspector reviewed personnel performance and actions to operate the fuel handling equipment during the November 1996 defueling. No inadequacies were identified. This item is closed.

M8.3 (Open) IFI 93-01-01: Safety Instrument Calibrations

This item was open pending the completion of licensee actions to assure instruments used to satisfy technical specification surveillances are periodically calibrated. Section E8.2 of this report (see LER 96-27) describes additional discrepancies regarding the failure to calibrate temperature instruments used on the safety related boric acid heat trace circuits. This item remains open pending further NRC review of licensee corrective actions.

III. Engineering

E1 Conduct of Engineering

E1.1 Instrumentation Setpoint Control (EEI 96-11-04)

a. Inspection Scope (92903)

The scope of this inspection included a review of the licensee instrumentation setpoint calculation program associated with the reactor protection system, engineered safeguards features systems and a sample of other instrumentation included in the plant technical specifications. The inspectors also reviewed the engineering procedures utilized to perform instrument uncertainty and setpoint calculations. A sample of setpoint calculations were reviewed to assess the methods utilized in the calculation and the overall quality of the engineering work.

b. Observations and Findings

Setpoint Calculation Program Development

The inspector reviewed factors and events associated with the development of instrument uncertainty and setpoint calculations. The initial technical specification trip setpoints and allowable values were provided by the nuclear steam supply system (NSSS) vendor during the initial plant construction and licensing. The plant modification to replace the reactor protection system identified the need to perform setpoint calculations as part of the modification process in 1983.

Licensee Event Report (LER) 90-022 reported a miscalibration of auxiliary feedwater flow transmitters. At that time, a long term corrective action was identified that consisted of the systematic evaluation of critical safety-significant setpoints and developing uncertainty calculations to support the selected hardware setpoints. In 1991, Project Authorization (PA) 91-064 initiated a Setpoint Verification Program for the reactor protection system, engineered safeguards features systems and primary containment isolation system instruments. This PA was to address the long term actions identified in LER 90-022.

Responsibility for the setpoint verification program was transferred from the corporate engineering organization to the site in 1994 following the reorganization of the engineering departments. The setpoint verification program effort was combined with the project to revise the technical specifications to support a 24-month fuel cycle. The calculations required for the 24-month fuel cycle technical specification change were completed in 1995 and the proposed technical specification revision was submitted to the NRC on December 20, 1995.

Engineering Procedures

The inspector reviewed procedures SP-ST-EE-286, Rev. 6, "Guidelines for Calculating Instrument Uncertainties," and SP-ST-EE-320, Rev. 1, "Guidelines for Calculating Instrumentation Setpoints for Safety Systems." The procedures were initially issued in 1989 and 1993 respectively, and both procedures utilize methods described in the Instrument Society of America (ISA) Standard ISA-S67.04, "Setpoints for Nuclear Safety-Related Instrumentation." The NRC endorsed the use of the ISA methods in USNRC Regulatory Guide 1.105, Revision 2, "Instrument Setpoints for Safety Related Systems."

The inspector found the procedures to be generally of good quality. However, the inspector did note that SP-ST-EE-320 did not include an allowance for seismic effects (SE) when calculating the setpoint allowable values. The inspector noted that, although not included in the procedure, the calculations performed to support the 24 month fuel cycle did include the SE and the licensee acknowledged that a procedure correction was necessary.

Calculations that were performed prior to 1989 appear to have used the ISA 67.04 and R.G. 105 guidance directly since there were no engineering department procedures that provided specific guidance on performing instrumentation uncertainty and setpoint calculations.

Calculation Program Findings

The licensee approach for calculating allowable values and trip setpoints for instruments is summarized as follows:

(1) The analytic limit for the parameter monitored by the instrument is obtained from the safety analysis engineer and is the value assumed in the safety analysis that supports the design basis of the safety system.

(2) The errors that contribute to the total instrument loop uncertainty are calculated and categorized as either errors that are not observable during routine testing and calibration and those that are observable. Those errors that are not observable are combined to calculate a term designated as Allowance No. 1. Observable errors are combined and designated as Allowance No. 2.

(3) The allowable value, defined in procedure SP-ST-EE-320 as a "limiting value that the trip setpoint may have when tested periodically beyond which appropriate action shall be taken," is then calculated as follows:

Allowable value = analytical limit ± Allowance No. 1.

(Allowance No. 1 and Allowance No. 2, discussed below, are added or subtracted depending on whether the trip occurs on an increasing or decreasing value.)

(4) The trip setpoint, which is defined in procedure EE-320 as a predetermined value for actuation of the final actuation device to initiate protective actions, is calculated as follows:

Trip setpoint = allowable value ± Allowance No. 2.

For example, with an instrument trip that occurs on an increasing value the relative values would be established as follo.vs:

____________________ **Analytical Limit**

↑

Allowance #1

↓

____________________ **Allowable Value**

↑

Allowance #2

↓

____________________ **Trip Setpoint**

↑

Operating Margin

↓

____________________ **Normal Operating Point**

Where Allowance No. 1 includes the following terms, as applicable:

Process Measurement Accuracy (PMA)
Primary Element Accuracy (PEA)
Sensor Temperature Effects (STE)
Sensor Pressure Effects (SPE)
Rack Temperature Effects (RTE)
Harsh Environment Effects-Radiation Allowance (RA)
Insulation Resistance Effect (IRE)
LOCA/HELB Effects (DLH)
Additional Margin (AM)

And Allowance No. 2 is the resultant of the following terms:

Sensor Calibration Accuracy (SCA)
Sensor Drift (SD)
Rack Calibration Accuracy (RCA)
Rack Drift (RD)
Measurement and Test Equipment Accuracy (MTE)

Procedure SP-ST-EE-320 permits the inclusion of additional margin in the Allowance No. 1 term to reduce the probability of exceeding the analytical limit.

The inspector also noted that the plant technical specification (TS) bases for TS 2.2.1, "Reactor Trip System Instrumentation Setpoints," provides information relative to trip setpoints and allowable values. Specifically, the bases states that "Operation with a trip set less conservative that its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable value is equal to or less than a drift allowance accounted for in the design basis analysis."

The inspector identified the following issues with the setpoint control program:

(a) During the performance of the calculations for the 24 month fuel cycle the value of Allowance No. 2 was increased by the inclusion of an "additional margin (AM)" term when combining the uncertainty effects that are observable during testing and calibrations. Including the AM term in Allowance No. 2 resulted in additional margin between the analytical value and the trip setpoint. However, the difference between the trip setpoint and the allowable value was no longer less than or equal to the drift allowance that should be accounted for according to the setpoint calculation procedure, SP-ST-EE-320 and as discussed in the TS bases. As a result, excessive instrument drift could occur before the condition would be identified and evaluated for operability and the need for corrective action. In some cases the amount of AM included in Allowance No. 2 was very significant. For example, in calculation PA 90-013-321EY, Revision 1, "Uncertainty Calculation For Steam Flow Loops F-1201-1B,-1C,-2B,-2C,-3B,-3D,-4B,-4D and Setpoint Calculation For Steam Flow/Feedwater Flow Mismatch," the calculated uncertainty for Allowance No. 2 was 25,250 lbm/hr and the AM added was 33,430 lbm/hr. This resulted in the difference between the trip setpoint and the allowable value being more than twice the allowance that should have been included based on SP-ST-EE-320 and the plant technical specification bases. Similarly, in calculation PA 90-013-341EY, Revision 1, "Uncertainty and Setpoint Calculation For Steam Line Break Flow F-1202-1,-2,-3,-4," Allowance No. 2 was calculated to be 0.99% flow and an additional 1.01% flow was added as AM. The inspector concluded that the addition of AM in the Allowance No. 2 term was not appropriate and defeated the purpose of establishing allowable values.

(b) In addition to reducing the effectiveness of the allowable values by the addition of AM in Allowance No. 2, the inspector noted that sensor drift effect and sensor calibration accuracy values in the uncertainty calculations were arbitrarily increased to provide added "conservatism." The inspectors agreed that this practice would add conservatism between the analytical value and the trip setpoint. However, the difference between the trip setpoint and allowable value again would not be equal to or less than the expected component drift. For example, calculation 95-01262EY, Revision 0, "Uncertainties and Setpoints for RCS Flow Loops F-401A,C,D; 402A,C,D; 403A,C,D; 404A,C,D," determined that the sensor calibration accuracy for the Foxboro transmitters in the loop were ±0.52% of span and the sensor drift was ±3.81% of span. However, one transmitter (FT-402D) is a Model 1154 Rosemount transmitter that has a manufacturer-specified sensor calibration accuracy of ±0.25% of span and an expected drift of ±0.28% of span based on a licensee drift analysis. In the setpoint calculation the sensor drift and sensor calibration accuracies for the Foxboro transmitters were used for all transmitters for conservatism. The inspector concluded that the use of these values for the Rosemount transmitter could again allow excessive drift to go undetected.

The failure to assure that the allowable values were determined in accordance with the design basis is a violation of 10 CFR 50 Appendix B, Criteria III, Design Control. **(EEI 96-11-04)** This is the first of two examples of a design control violation.

(c) The inspector reviewed the instrument testing and calibration process to determine how testing or calibration failures were evaluated to determine if the instrument as-found data was within the technical specification allowable value and to evaluate instrument operability. The inspector noted that the instrument loop components are generally tested or calibrated on a component level bases versus an integrated loop calibration. The licensee initially stated that the acceptance criteria for each of the loop components was conservative relative to the potential errors determined in the uncertainty calculations. As such, test and calibration data that met the procedure specifications would ensure that the loop was performing within the technical specification allowable values. The inspector reviewed several surveillance procedures and found that the acceptance criteria was not consistent for similar components in different instrument loops, and in some cases, the acceptance criteria specified in the tests was not conservative relative to the instrument uncertainties determined in the calculations. For example:

- Procedure SUR 5.2-6.1, "Steam Generator #1 Narrow Range Level Channel Calibration," specifies an acceptance criteria of ±1.0% of span for Model 1154 Rosemount transmitter LT-1301-1A,-1C and -1D. Calculation PA 90-013-262EY, Rev. 2, "Uncertainties and Setpoints for Steam Generator Narrow Range Level L-1301-1A/C/D, 2A/C/D, 3A/C/D ,4A/C/D," specifies a sensor calibration accuracy (SCA) of ±0.25% of span for the transmitter. This value (±0.25% span) is applied as a sensor calibration tolerance for another Model 1154 Rosemount transmitter for instrument PT-1201-2B in surveillance procedure SUR 5.2-11.2, "Steam Generator #2 Train A Steam Flow, Feedwater Flow, Steam Generator Pressure Channel Calibration." The inspector concluded that the use of ±1.0% span acceptance criteria was inappropriate since even when all factors associated with the sensor calibration (i.e. sensor calibration accuracy, sensor drift and measurement and test equipment accuracy) are considered, the total probable error would be ±0.6% of span. Therefore, the use of ±1.0% would allow a sensor with excessive drift to be found acceptable during the calibration. The inspectors reviewed the results of surveillance procedure 5.2-6.1 that was completed on March 6, 1995, and found that the as found calibration data for transmitter LT-1301-1A would have failed a ±0.6% acceptance criteria.

The failure to ensure that the results of the engineering calculations were translated into plant procedures is an apparent violation of 10 CFR 50 Appendix B, Criteria III, Design Control. **(EEI 96-11-04)** This is the second of two examples of a design control violation.

Specific Calculation Errors

In addition to the programmatic issues identified above, the inspectors noted the following specific errors in setpoint calculations:

- In calculation 95-01262EY, Revision 0, "Uncertainties and Setpoints for RCS Flow Loops F-401A,C,D; 402A,C,D; 403A,C,D; 404A,C,D," the instrument span is -0.5 to 30 psid and Allowance No. 1 and Allowance No. 2 were calculated as a percent of the instrument span. The useable span is 0.0 to 30 psid which correlates to 0 to 100% of rated reactor coolant system (RCS) flow. When the allowable value and trip setpoints were calculated, the percent span errors were added to the percent RCS flow values without first adjusting percent span errors to a corresponding percent flow.

- In calculation 93-ENG-552EY, Revision 0, "Uncertainty and Setpoint Calculation for Pressurizer Level L-401-1,-2,-3,-4," the rack temperature effect (RTE) term was not included in the calculation of Allowance No. 1. The inspector did note that there was additional margin included in the Allowance No. 1 term that was greater than the omitted term and therefore there was adequate margin between the analytical value and the trip setpoint.

- In calculation IC-CY-1451EY, Revision 0, "Uncertainties and Setpoints for the Wide Range Nuclear Flux Monitoring System Startup Rate Reactor Trip Channels WR1, WR2, WR3, and WR4," the allowable value was incorrect due to a transposition error. The inspector noted that the licensee had also identified and corrected this error when the calculation was subsequently revised for other reasons.

- Calculation IC-CALC-90-026, "RCS Low Flow Channel Accuracy/Safety Setpoint Calculation," improperly concluded that the technical specification allowable value was adequate although the margin between the trip setpoint and allowable value was excessive and therefore not consistent with the technical specification bases. Also, the calculation assumed that rack drift was zero without providing any justification for the assumption and the calculation did not consider sensor drift and sensor calibration accuracy when assessing the adequacy of the existing allowable value.

Effects on Analytical Limits and Accident Analyses

The inspector discussed the impact of the 24 month fuel cycle calculations with a member of the accident analysis group. The results of the 24 month cycle calculations supported the existing analytical limits and no additional accident analyses was required. The previously established setpoints provided sufficient margin to the analytical limits to ensure safe operation. However, as discussed above the allowable values were not set sufficiently conservative to ensure detection of excessive instrument drift.

The licensee acknowledged the issues identified by the inspector and documented these concerns and other related issues in an adverse condition report.

c. Conclusions

The inspector concluded that there were weaknesses in the setpoint control program that resulted in incorrect calculation results and inappropriate calibration procedure acceptance criteria. The licensee did not establish clear engineering procedures on how to perform setpoint calculations until 1993. The errors identified indicate that a review and assessment of the accuracy of the information submitted in the technical specification change request is warranted. The inspectors also concluded that the independent review process was not effective in identifying programmatic or specific calculation errors. The potential safety consequences of the identified deficiencies were minor because appropriate conservatisms were included in the uncertainty factors that make up Allowance No. 1 and the additional margins that were included in the Allowance No. 2 uncertainty factors combined to increase the margin between the analytical limits and the trip setpoints. The detrimental effects of the problems were that the inflated difference between the allowable values and the trip setpoints impaired the ability to detect components that had excessive drift or may have been degraded and trending towards failure.

E1.2 Instrumentation Calibrations (EEI 96-11-05)

a. Inspection Scope (92903)

The inspectors reviewed the licensee procedure for evaluating and dispositioning instrumentation calibration results that do not meet the established acceptance criteria.

b. Observations and Findings

The licensee procedure for performing instrumentation calibration reviews is WCM 2.3-7, Revision 2, "Instrument Calibration Review." This procedure requires that an Instrumentation Calibration Review (ICR) Form be processed for each instance when a surveillance procedure is performed and the as-found calibration data is outside of the acceptance criteria. The ICR form is utilized to document whether or not the drift was in the conservative or non-conservative direction and to document whether or not the calibration was within the technical specification limits. The procedure also provides directions to assess whether the failure is reportable in accordance with the requirements of 10 CFR 50.72 and 10 CFR 50.73 and to implement corrective action to prevent recurrence based on instrument performance and history.

The inspectors reviewed several completed ICRs and found the following:

(1) ICRs 95-009 and 95-011 documented calibration failures for two identical model Rosemount transmitters. The only corrective action was for the failure to be tracked by the system engineer. The reviews did not question the adequacy of the acceptance criteria even though there was different criteria for identical components. The procedure associated with ICR 95-009 specified an acceptance criteria of ±1.0% of span and the other specified ±0.25% of span. Also, when the as-found data was evaluated to determine if the technical specification allowable values were exceeded, only the affected components were evaluated and the combined effects of all of the loop components were not assessed.

(2) ICRs 95-23 and 95-24 documented the cause of the failures as drift and the only corrective actions were to recalibrate.

(3) ICR 95-025 documented a failure of a Foxboro rack component and the cause of the failure was documented as unknown, the component was adjusted and no additional corrective action was taken.

c. Conclusions

The inspectors concluded that the licensee did not adequately determine the root causes of instrument calibration failures nor were adequate corrective actions taken to prevent recurrence. None of the ICR evaluations considered potential corrective actions such as adjustment of testing frequency, setpoint revision, reevaluation of the trip setpoint or allowable value, evaluation of equipment installation and environment, evaluation of calibration equipment and technique or repair or replacement of the component. The failure to implement adequate corrective actions for instrumentation failures is an apparent violation of 10 CFR 50 Appendix B, Criteria XVI. **(EEI 96-11-05)**

E2 Engineering Support of Facilities and Equipment

E2.1 Temporary Spent Fuel Pool Heat Exchanger Cooling

a. Inspection Scope

The inspection scope was to evaluate the implementation and controls for temporary cooling supply of service water to the spent fuel pool heat exchangers. The temporary cooling was required to affect repairs to the service water supply pipe to the spent fuel pool heat exchangers.

b. Observations and Findings

On October 11, 1996, the licensee isolated service water to the "A" spent fuel pool heat exchanger. The reason for the isolation was to prepare for installing a temporary modification to supply cooling to the heat exchanger. The temporary modification was required to make repairs to the permanent service water supply piping that had indication of severe pipe degradation.

The service water was isolated to the spent fuel pool cooling heat exchanger for approximately 13 hours between October 11 and October 12, 1996. The spent fuel pool temperature increased approximately 13 degrees fahrenheit (F) to a maximum of 86 F. The design basis temperature for the pool is 150 degrees F.

The temporary modification installed two three (3) inch fire hoses from the service water filter drain connection to the supply of the "A" spent fuel pool heat exchanger. The connection to the inlet of the "A" spent fuel pool heat exchanger required the removal of the permanently installed piping and the connection of a spool piece with fire hose connections.

The licensee concluded that the temporary modification was not an unreviewed safety question as defined in 10 CFR 50.59. The postulated malfunctions evaluated included the rupture of the fire hose and affects on internal flooding in the primary auxiliary building, inadequate flow to the spent fuel pool heat exchangers, loss of service water, and response of the fire hoses during a seismic event. A prerequisite for installation was that flow through the hoses was in excess of 100 gallons per minute (gpm) to maintain the pool temperature in the normal operating bands. The licensee confirmed this by measurement. Redundant fire hoses were staged as an additional contingency if one of the two hoses burst. UFSAR accidents evaluated were the loss of spent fuel pool cooling, loss of normal power event, boron dilution event, and fuel handling accident inside containment. The installation and removal of the temporary modification occurred prior to fuel movement.

The installation of temporary cooling was supported by procedure changes to NOP 2.24-3, Filtered Service Water System and Adams Filter Operation, and SUR 5.1-0A, Steady State Operational Surveillance (Modes 5 and 6). The procedure changes provided guidance on installation of the jumper, control of flowrate to the spent fuel pool (SFP) heat exchanger, response to a failed hose, and actions necessary to remove the temporary modification. The change to SUR 5.1-0A was to add a check by the NSO every eight hours to verify no leakage, and to walkdown the entire length of hose.

The inspector walked down the installation of the temporary modification on October 13, 1996. The installation appeared to be appropriately supported at various locations and was installed in accordance with the documentation of the modification. In addition to the installation walkdown, the inspector independently verified that tag clearance 96-1006 was adequate to isolate the service water system from the temporary installation. The temporary modification was removed on October 30, 1996.

c. Conclusions

The temporary modification to supply cooling water to the spent fuel pool was performed satisfactorily, with appropriate contingency planning and monitoring of pool temperatures.

E2.2 Spent Fuel Pool Cooling Check Valve Replacement

a. Inspection Scope

The inspection scope evaluated the operability of the spent fuel pool cooling system with one of the two spent fuel pool cooling pump discharge check valve internals removed.

b. Observations and Findings

On September 28, 1996, the spent fuel pool system engineer documented to licensee management that there was no condition that could adversely affect availability of spent fuel pool cooling in Mode 6 operation. The system engineer initially concluded that the "B" spent fuel cooling pump was operable with the internal parts of the discharge check valve (SF-CV-866) removed under temporary modification 96-12.

The inspector questioned this decision since technical specification (TS) 3.9.15 states that spent fuel pool cooling shall be operable with both pumps operable and at least one cooling pump and plate heat exchanger in operation. Additionally, surveillance procedure SUR 5.3-51, Refueling Operations, step 1.3.6, requires prior to movement of irradiated fuel to the spent fuel pool, that the licensee verify that both spent fuel cooling pumps are lined up to provide flow to the plate heat exchanger. With the valves internals removed from SF-CV-866 the manual discharge isolation valve for the "B" spent fuel pool cooling pump would be closed to assure operability of the A pump. Thus, the B pump could not be lined up as required, but would require manual operator action to be placed in service. The licensee acknowledged the inspector's concern.

The licensee implemented a previously planned plant modification to replace both spent fuel pool discharge check valves and relocate the "B" check valve further away from the pump, and in conformance with industry guidelines on locations of check valves from bends in piping systems. The modification was completed prior to refueling activities on November 11, 1996.

The inspector noted the following regarding this condition. First, the "B" SFP discharge check valves internals have been removed since March, 1996 without timely corrective actions. Second, the licensee overcame the component deficiency by implementing a procedure change to NOP 2.10-1, Spent Fuel Pit Cooling System Operation by requiring the manual discharge valve on the "B" SFP cooling pump when not operating to be closed. Third, when the internals were removed from SF-

CV-866 in March, 1996, the licensee concluded that no affect on operability existed; however, TS 3.9.15 was not applicable at that time.

c. Conclusions

The licensee's initial decision-making on operational readiness of the spent fuel pool cooling system for defueling operations was non-conservative with respect to the technical specifications and the implementing surveillance procedure. A planned modification was completed prior to defueling activities to restore the cooling system to an improved configuration. Initial corrective actions were not timely to address deficient material conditions.

E2.3 Inadequate Auxiliary Building Flood Protection (EEI 96-11-06)

a. Inspection Scope

The inspection scope was to evaluate licensee actions in response to a plant configuration deficiency as it related to internal flood protection in the PAB.

b. Observations and Findings

On October 23, 1996, the licensee identified various floor penetrations in the PAB that did not provide assurances that the response times assumed in the licensing basis was conservative for the worst-case internal flood scenario. Approximately, thirty-five (35) penetrations did not have a 24 inch high carbon steel barrier.

In 1973, the licensee implemented plant modification (PDCR 156, Flooding Protection of Safeguards Equipment) in response to an Atomic Energy Commission (AEC) letter to the licensee in August, 1972. The AEC letter requested the licensee to review the facility design and determine if equipment that does not meet criteria of Class I seismic construction could cause flooding sufficient to adversely affect the performance of engineered safety systems. Additionally, the licensee was asked to consider if the failure of any equipment could cause flooding such that common mode failure of redundant safety related equipment would result. The modification installed steel barriers around piping penetrations on both elevations of the primary auxiliary building and around the engineered safety features pumps. At the time, the licensee did not install pipe barriers for penetrations in areas connected to the pipe chase since no credit was taken in the flood analysis for the additional delay time to flood the RHR pumps (i.e. taking into account the delay of flood water flow through the pipe chase and ultimately to the RHR pumps). This was documented to the NRC is a letter dated August 1, 1975.

The NRC's safety evaluation in support of technical specification amendment 27 (July 20, 1978) concluded that it was appropriate to add area flood annunciators and operability requirements to the technical specification to provide adequate operator response time to determine the source of leakage and to take corrective action. In the safety evaluation, the licensee concluded that approximately 12 minutes were available for operator action to terminate flooding in the PAB for the worst case break of the service water return piping from the component cooling water heat exchangers. The NRC position as documented in the safety evaluation was that credit for operator action is not assumed during the first ten minutes of a postulated event. Since the worst-case analysis calculated a 12 minute response for operator action, no automatic trip of the service water pumps was required.

The licensee performed further reviews of PAB flooding, as described in LER 96-08 (reference Inspection 96-06, Section E3.1). Licensee calculation 96-PABFLOOD-01497 (November 7, 1996) concluded that the RHR pumps would be inoperable in 7 minutes without operator action to mitigate or isolate the leak, and approximately 6 minutes after receiving the flood alarm in the RHR pit. This revised calculation contributed to the identification on October 23, 1996 that various piping penetrations (accumulated two square foot opening) did not have flood barriers installed.

Licensee corrective actions upon identification were to establish a flood watch in the PAB to provide for early detection and isolation of the worst-case scenario pipe failure. This watch was established 24 hours a day until November 15, 1996 when all of the reactor fuel was removed from the reactor vessel, and RHR operability was not required.

This condition represents a violation of 10 CFR 50 Appendix B, Criterion III **(EEI 96-11-06)** in that measures to assure applicable regulatory requirements and design basis for structures were not correctly translated into specifications. Specifically, the lack of flood barriers around the piping penetrations invalidated the basis for operator response time to mitigate an internal flood scenario. An apparent cause for this violation was lack of engineering rigor in a past plant modification.

c. Conclusions

The inspector noted a lack of engineering rigor for a past modification to protect safety equipment from an internal flood scenario. The modification did not require flood barrier installation for approximately thirty-five (35) penetrations. This failure resulted in a non-conservative flood analysis regarding operator response time to mitigate the event. This condition is considered a violation of 10 CFR 50 Appendix B, Criterion III.

E2.4 Porous Concrete Sub-Foundation

a. Inspection Scope

The scope of this inspection was to determine whether the concrete beneath the containment base mat was eroding.

b. Observations and Findings

The NRC issued a request for information by letter dated October 18, 1996, to evaluate the potential generic implications of the erosion of cement from underneath the containment foundation basement. As shown on plant design drawing 16103-56024, a six inch thick layer of porous ("popcorn") concrete was installed during plant construction beneath the containment foundation mat.

By letter dated October 21, 1996, the licensee reported that there has been no evidence to date of cement erosion from under the basemat. The licensee reported that: (i) water from the basemat leaching out into the external containment sump has been monitored monthly for ten years and there has been no evidence of slurry in the effluents; (ii) although there have been no program in place to systematically monitor the settlement of the containment building, the recent inspections performed under procedure ENG 1.7-147 (as part of the Maintenance Rule) found no evidence regarding concrete settlement nor any indications of degradation of the concrete slab.

c. Conclusions

The inspector confirmed during routine inspection tours of plant areas and structures that there were no obvious signs of slurry in the discharged from the external sump, or of settlement in the containment structure. No inadequacies were identified.

E2.5 Spent Fuel Pool Cooling System Single Failures (URI 96-11-07)

a. Inspection Scope (37551)

On October 22, 1996, the licensee issued ACR 96-1239 to describe an inconsistency in the licensing basis for the spent fuel pool cooling system (SFPCS). The ACR noted that the current design of the SFP cooling pump power supplies does not support the bases for Technical Specification 3/4.9.15, which states that "single failure considerations require that both spent fuel pool cooling pumps are OPERABLE." Both SFP pumps are powered from a Train A electrical source. The ACR was written to evaluate the condition prior to the mode of applicability for TS 3/4.9.15 (Mode 6 during transfer of fuel to the spent fuel pool for a full core offload).

The inspector completed a walkdown of the spent fuel cooling system and associated power supplies, and reviewed the design basis and licensing basis as described in PDCR 1592, UFSAR Section 9.1, the safety evaluations and licensing submittals in support of Amendment No. 7 (June 8, 1976) and Amendment No. 188 (January 22, 1996), SEP Topic IX-1 for spent fuel storage and, the CMP position paper "Spent Fuel Pool Cooling System Redundancy/Single Failure Capability (draft). The inspector reviewed normal operating and emergency procedures for spent fuel pool cooling.

b. Observations and Findings

SFPCS Design Details

The SFPCS consists of two non-safety related pumps which provide forced cooling through two heat exchangers. The A pump has a 40 hp motor and a capacity of 610 gpm; the B pump has a 60 hp motor and a capacity of 620 gpm. The A (shell and tube) heat exchanger has a heat capacity of 6.2 MBtu/hr; the B (plate) heat exchanger has a heat capacity of 20 Mbtu/hr.

The SFPCS alignment for normal operation (NOP 2.10-1) is to use one SFP cooling pump with the A SFP heat exchanger, and for refueling operations (full core offload) is to allow one or both SFP pumps operating with the B heat exchanger. Both the A and B SFP pumps are powered from 480 V MCC-2, which is a non-class 1E power supply. MCC-2 has two subsections which are physically located adjacent to each other, but are electrically separate. SFP pump P21-1A is connected to subsection MCC2-4, which is powered from Bus 4; pump P21-1B is connected to MCC2-5, which is powered from Bus 5. Both 480 volt Bus 4 and Bus 5 are part of the A train electrical division.

The A electrical division receives normal power from the 115 KV electrical distribution system via line 1772, transformer T389 and Bus 1-2. During a LNP condition, the SFP cooling pumps would be load shed on loss of power, and manual operator action is required to restart a pump to restore cooling. The A train emergency diesel generator, EG-2A, can be used to provide emergency power to Bus 4/5 and MCC2. The licensee recently installed a non-class 1E, air cooled diesel, EG-7, to meet SEP concerns for tornados; this power supply can be operated manually and connected to 4160 volt Bus 1-2, and thereby power the A electrical division.

Original and Modified Licensing Basis

The SFPCS design when the plant was first licensed included one SFP pump and one heat exchanger. Thus, no considerations for single failures were included in the original design. The SFPCS design was modified in support of Amendment 7 to add the second pump (P21-1B) and heat exchanger (E10-1B). Although redundancy was added for the pumps (active components in the SFPCS), the design relied on a single heat exchanger (plate) to remove the heat of a full core offload. While the thermal analysis for both Amendment 7 and 188 demonstrated the cooling system was adequate for a worst case heat load and assuming a loss of one SFP pump, there was no change to the electrical distribution system or to the single electrical train dependency.

UFSAR Section 9.1 (March 1996) describes the SFPCS but does not provide design details on the electrical supplies. UFSAR Figure 9.1-1 does show that both SFPC pumps are powered from MCC2. The licensee submittals in support of Amendment #188 do not describe the electrical system details. The licensee stated that 1996 rerack project did not change the electrical design or the design basis of the SFPCS, and thus there was no reason to address this detail in support of Amendment #188.

The licensing basis provided clear references that equate single failure considerations to the loss of one of the SFP cooling pumps. Examples from the licensee's March 31, 1995 letter (B15136) in support of Amendment #188 include: (i) page 9, third paragraph - "The analysis determined that the cooling system has sufficient capacity to maintain bulk pool temperature at or below 150F for any postulated discharge scenario including the single active failure of the most efficient pool cooling pump"; (ii) page 17, third paragraph - "The pool will not exceed 150F during the worst single failure of a cooling pump"; and, (iii) safety evaluation page 5-5 and Figures 5.4.2, 5.8.2 through 5.8.4 - "single active failure: one SFP cooling pump left running."

Design Calculations - Thermal Analyses

The licensee analyzed the SFPCS capability by calculating decay heat loads per the NRC's standard review plan (SRP) BTP ASB9-2 and evaluating three discharge scenarios, all involving a full core offload at the end of the final cycle of plant operations. Decay heat load calculations were conducted for Amendments 7 and 188 to assess the adequacy of the spent fuel pool cooling system to handle the heat with the racks fully loaded to the maximum capacity (1172 and 1480, respectively). The calculations were performed using conservative assumptions that would minimize heat removal capabilities, and discharge scenarios that would maximize the heat input to the pool. The Amendment #188 analyses were performed for three scenarios: Scenario 1 - normal EOC full core offload with two pumps aligned to the plate heat exchanger; Scenario 2 - EOC full core offload, with a single active failure; and, Scenario 3 - BOC emergency full core offload after the last plant operating cycle (this case evaluates more fuel assemblies than can be stored in the pool) with two pumps aligned to the plate heat exchanger. The river temperature assumed for the Amendment #188 analyses was 90 F.

For scenario 2, the analysis started with a SFPCS configuration of one pump aligned to the plate heat exchanger, assuming the failure of the redundant pump. The maximum SFP temperature was limited to 150F, and the analysis determined what incore decay time was required on the discharged fuel to assure this limit would be met. The required minimum in-core hold times were calculated for different service water temperatures - 90F, 85F, 80F, and 75F. The analyses showed that the SFPCS capacity with one pump and the plate heat exchanger in operation was sufficient to limit pool temperatures to 150F for the assumed in-core hold times prior to discharge. The only single failure assumed in any of the licensing basis analyses was one of the two SFPCS pumps.

The licensee also analyzed the time to boil under emergency conditions in which the heat exchanger assisted forced pool cooling becomes unavailable for any reason. This analysis was also conservative and assumed the pool was at the maximum allowed temperature of 150F when cooling was lost and the maximum heat load was present. The calculated minimum time from loss of cooling to pool boiling was just over 7 hours (7.09) with a maximum boil-off (required makeup) rate of 47 gpm. The analysis showed that if no action were taken to replenish the pool inventory, the time to fuel uncovery was about three days (68 hours).

The licensee has the capability to make up to the SFP from either the RWST or the fire water system powered by a diesel fire water pump. In the Safety Evaluation dated 1/22/93, the NRC found that the contingency plan of cooling the pool by allowing the pool to boil and adding makeup water in the event of a complete loss of cooling met the guidance of SRP 9.1.3, and was therefore acceptable.

Design Versus Actual Heat Loads

The inspector compared the actual maximum heat loads against the conservative assumptions used in the licensing basis thermal analyses. For Amendment #188, the licensee demonstrated that the SFPCS was sufficient to handle a worst case heat load of 22.4 X 10+6 Btu/hr, which assumed a full core offload at the end of plant life in 2007 with all 1480 storage locations filled. The present pool plus core inventory is (862+157=) 1019 spent fuel assemblies. This number when placed in the pool is less than the previous analyzed (licensed) limit of 1172; thus, the past licensing basis thermal analysis is still bounding.

However, using the Amendment 188 analyses, the assumed river temperature was 90F; the actual temperature in October 1996 is about 55F, and the river is cooling down. The minimum core residency time in the analysis was assumed to be about 7 days prior to discharge to the pool. The reactor was shut down on July 22, 1996, and as of November 1 the fuel has decayed for 116 days. The estimated combined heat load of the core and the old fuel in the SFP is now less than 5.6 X 10+6 Btu/hr, which is within the capacity of either the plate or the shell heat exchanger operating with a single SFP pump. The time to boil in the spent fuel pool prior to core offload was 252 hours, which decreased to about 60 hours with all 1019 fuel assemblies in the pool.

Abnormal Operating Procedures

The licensee has contingency plans to mitigate a loss of SFP cooling. Blind flanges are installed in the SFPCS piping at the inlet and outlet of the heat exchangers that could be used with diesel powered pumps to provide continued forced cooling; however, this method is no longer credited. AOP 3.2-59 provides several methods for supplying alternate cooling and providing makeup to the pool. The licensee has recently demonstrated the capability to implement compensatory measures to provide alternate service water cooling to the SFPCS heat exchangers. Emergency procedure 3.1-10 provides direction for the operator to power MCC2 from B electrical train Bus 7. This would be accomplished by manipulating 480 volt breakers in the A switchgear room. The inspector estimated through interviews and a walk through of the procedure that the contingency could be implemented in less than 1.5 hours. The licensee has used this lineup in the past during plant outages.

The existing instructions in EOP 3.1-10 (revision 17) would provide B train power to P21-1A. The EOP further directs the operator to request technical support to process a bypass jumper to power P21-1B from the P21-1A breaker with jumper cables. A bypass could be used to provide A or B train power to P21-1B either locally at MCC2, or at the pump. Finally, the licensee prepared a change to the EOPs to provide a method to provide B train power to P21-1B without the use of jumpers (by using 480 volt breaker manipulations to bring Bus 7 power to Bus 5 via MCC5).

The inspector concluded that, despite the single train vulnerabilities inherent in the as-built SFPCS design, there were multiple power supplies for the A train electrical system, as well as several viable methods to provide alternative power feeds to the SFPCS from the B electrical distribution system.

Clarified Licensing Basis - Single Failure Criteria

The licensee issued a change to the bases of TS 3/4.9.15 under 10 CFR 50.59 (reviewed by PORC), that clarified the intent of the licensing basis. The revised bases (TS Clarification Sheet C-TSC-072 dated 10/23/96) defined that the requirement to have both SFP cooling pumps operable provides backup capability in the event that an operating pump fails. This action was completed to address ACR 96-1239 prior to entry into Mode 6.

The NRC Safety Evaluation dated January 22, 1996 issued in support of Amendment #188 contains wording that tends to broaden the single failure features intended by the design or the licensee submittals. In particular, in Section 2.2 on page 5, second paragraph, the SER states..."Three scenarios were evaluated: end-of-cycle with full core offload, end of cycle and single active failure in the SFPCS, and an emergency core offload..." Again, in Section 2.2 on pages 5-6, last paragraph states..."Results of the revised analysis also indicate that in order for the SFPCS to maintain the pool water temperature at or below 150F during refueling with a full core offload and a single failure in the SFPCS, it is necessary to impose a fuel handling delay time after shutdown..." Further, the bases for TS 3/4.9.15 suggests that redundant pump operability would require redundant power supplies.

c. Conclusions

The SFPCS was not designed to perform its function under any postulated single failure, and relied on a single electrical distribution system (Train A). The SFPCS was designed to provided adequate cooling for a full core offload, assuming the loss of one of the two spent fuel pool cooling pumps. The licensing basis did not represent that the SFPCS was single failure proof in support of license Amendments #7 and #188; however, the licensing basis lacks details regarding the electrical power supply for the SFPCS, and it is not clear that the electrical system vulnerabilities were recognized during the licensing reviews for Amendments #7 and #188.

The licensee has emergency procedures in place that provide alternate methods to provide power to the SFPC pumps from the train B electrical system; further procedures were changed to provide additional alternate methods. The licensee has evaluated the complete loss of spent fuel cooling and has shown that event can be successfully mitigated. This matter is considered unresolved pending further review of this issue by NRR and NRC management to determine whether any new information is present that warrants further licensing action **(UNR 96-11-07)**.

E2.6 Refueling Boron Concentration

a. Inspection Scope (37551)

The inspector reviewed licensee evaluations of the minimum reactor coolant system boron concentration needed to assure the minimum shutdown requirements of Technical Specification 3.9.1 were met.

b. Observations and Findings

The Core 20 design analyses to support the use of higher enriched reactor fuel in operating cycle 20 required the refueling boron concentration be 2400 ppm in the reactor coolant system. The licensee determined that a lower boron concentration was needed to meet shutdown margin requirements for end of operating cycle 19 conditions, taking credit for fuel burnup. The licensee left the new higher enriched fuel for cycle 20 stored in the new fuel storage vault due to the pending decision regarding the permanent shutdown of Haddam Neck. The results of the engineering evaluation were documented in a memorandum dated October 8, 1996 (NE-F-339). The licensee determined that a boron concentration of 1370 ppm would ensure the Mode 6 core multiplication factor would be less than 0.94 under all rods out conditions, and less than 0.89 with all rods inserted. The analysis also assured acceptable results were obtained for a postulated boron dilution event.

c. Conclusions

The licensee established an acceptable administrative limit on RCS minimum boron concentration of 1400 ppm. No inadequacies were identified.

E7 Quality Assurance in Engineering Activities

E7.1 Missed Commitments

a. Inspection Scope

The inspection scope evaluated the apparent causes and potential safety impact of missed commitments to a previous NRC violation and deviation.

b. Observations and Findings

In early November, 1996, the licensee informed the inspector that two of four commitments in response to a violation and deviation in inspection report 50-213/96-04 were not completed within the time frame documented to the NRC. The licensee's commitments were identified in a letter to the NRC on August 21, 1996. The two commitments that were not completed:

1) A comprehensive review of the inadequate safety evaluation that allowed for a sling attachment to the fuel handling tool in the spent fuel pool to be completed by October 31, 1996

2) A maintenance department revision to a on-the-job (OJT) training guide to require verification of physical qualification of crane operators by September 30, 1996.

The cause for missing the commitments was that no internal assignment was made to complete these actions, and the licensing person assigned to initiate the assignments was inexperienced. Notwithstanding these apparent causes, two of the four commitments were completed by the licensee's responsible departments initiation of an internal assignment.

For the first commitment, the licensee has subsequently initiated a safety evaluation and proposed UFSAR change to allow fuel handling activities in the spent fuel pool without the use of a sling.

The inspector confirmed that part of the second commitment had been completed by revising procedure work control manual (WCM) 2.2-9 on August 28, 1996, however one OJT guide for the containment polar crane had yet to be completed. The inspector verified that the OJT guides for the turbine building, RCA yard crane had been completed by September 30, 1996. The inspector also confirmed that containment polar crane operators during the current shutdown met the physical requirements of ANSI B 30.2.

At the end of the inspection, the licensee was completing actions to complete the corrective actions associated with the notice of violation in inspection report 50-213/96-04 with the initiation of an adverse condition report. The failure to implement two commitments within the time frame provided did not constitute additional violations of NRC requirements, but were examples of ineffective actions to avoid future violations or deviations. The inspector will evaluate licensee actions during review of open items 96-004-02 and 96-004-03.

c. Conclusions

Licensee failed to implement two commitments in response to a violation and a deviation due to less than adequate internal assignment development and inexperience personnel in the licensing organization.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Open) URI 96-01-03: RVLIS Design Basis

Previous Inspection

In NRC Inspection 96-01 the inspectors reviewed the methods used by the licensee to bypass a sensor in the RVLIS system and also reviewed the technical and safety evaluations to justify the continued use of the affected RVLIS channel.

During operating cycles 18 and 19 sensors #6 and #8 on the"A" RVLIS probe had become inoperable and were bypassed. In December 1995 sensor #7 on the same probe showed erratic indication. At that point it was the last operable sensor in the area between the top of the fuel and the top of the hot leg nozzle. Subsequent investigations and repairs resulted in the restoration of all but sensor #6 to operation prior to plant restart.

However, the licensee noted during a review for a potential bypass for sensor #7 that although the RVLIS train would remain operable within the technical specification requirements, the lack of any RVLIS indication in the lower plenum area at the area of the inlet and outlet nozzles would degrade technical assessment capabilities following postulated accident conditions. The inspectors concluded that the matter required further licensee review to determine whether the technical specifications as written were adequate.

The inspectors found that the affected channel was operable in accordance with the plant technical specification requirements and that the modifications were adequately addressed in the emergency operating procedures. However, the issue was unresolved pending further licensee review to: (i) assure the methods to bypass inoperable RVLIS sensors provides a conservative level indication; and, (ii) assure the present licensing basis is adequate to maintain RVLIS fully functional for intended uses under design basis conditions.

Current Inspection

During the current inspection the inspectors reviewed the status of the RVLIS system and licensee actions regarding inoperable sensors.

The inspectors reviewed the operating experience associated with the system and the process for addressing sensor failures. The period reviewed was from 1992 to the present. The inspector found that the system had a significant number of sensor failures up to the time that the probes were replaced in 1993. The initial probes had individual cables for each of the 8 sensors and some of the failures resulted with cable and/or connector problems. The model probes that were installed in 1993 have a single cable and connector design and there is currently only one failed sensor (sensor #6 in the "A" probe).

Operation with failed sensors was controlled primarily through the use of bypass jumpers. The bypass jumper process provides controls for the performance of technical and safety evaluations to support the bypassing of failed sensors. The inspectors reviewed safety evaluations associated with several bypass jumpers and found that the safety evaluations were detailed and included an evaluation of specific emergency operating procedure (EOP) changes that would be implemented as a result of the failed sensors. The bypass jumper, the safety evaluation and procedure changes are reviewed by the Plant Operations Review Committee (PORC). The licensee personnel interviewed indicated that normally all of the documents are presented to PORC at the same meeting and that there is not a significant delay in implementing the necessary procedure changes. The inspector noted that on February 5, 1992, bypass jumper 92-010 was written to address the failure of sensors 1A, 6A, 6B, 7B, and 8B. The safety evaluation was completed by engineering on February 10, 1995. The bypass jumper and associated safety evaluation were approved for implementation by PORC on February 11, 1992. The refueling was completed and critical operations resumed in March 1992.

On June 14, 1996, a technical specification clarification for the RVLIS system was approved by the PORC. The TS requires that at least three of the lower six sensors (plenum region) be operable and one of the two upper sensors (upper head) be operable to consider the RVLIS channel to be operable. The clarification specified that of the six lower sensors at least one of sensors 6,7, or 8 be operable for the channel to be considered operable. The vertical location of sensors 6,7 and 8 are at the centerline of the hot leg nozzle, at the bottom of the hot leg nozzle and just above the top of the fuel, respectively. The inspector noted that if sensors 7 and 8 were inoperable and sensor 6 was operable the RVLIS channel may not provide any useful indication of core coverage depending on where the postulated pipe break was located. For example, if the break was in the hot leg piping, water injected by the safety injection systems could be lost through the break and level may never recover to the centerline of the hot leg (i.e. location of sensor 6). The licensee agreed with this assessment and subsequently revised the TS clarification on September 20, 1996, to require that either sensor 7 or 8 be operable to consider a RVLIS train operable. The inspectors noted that prior to issuance of the TS clarification, the procedure changes were evaluated on a case-by-case basis depending on which sensors were inoperable and these evaluations reflected the approach delineated in the TS clarification.

The licensee indicated that the TS clarification will be considered for incorporation into TSs if the licensee converts to the improved standard technical specification format.

The inspector concluded that the licensee had implemented appropriate procedure changes in response to sensor failures and that the replacement of the RVLIS probes had improved the reliability of the system. The inspector also noted the failure of the licensee to identify the inadequacy of the technical specification to be another example of a weakness in the independent review process. This item remains open pending final licensee disposition, and NRC review, of the original issues in unresolved item 50-213/96-01-03 as summarized above.

E8.2 (Open) URI 96-02-03: Control Room Habitability

This item was open pending the completion of licensee actions to validate the procedure used to assess control room habitability under degraded plant conditions. Licensee action on this matter was summarized in a memorandum dated May 14, 1996 (HP-96-070). The licensee provided an integrated review of procedure RPM 2.3-3, which included participation by health physics, operations, engineering, licensing, radiological assessment, and emergency planning groups. Several deficiencies were identified and addressed: a determination that procedure EPIP 1.5-31 was the appropriate reference for guidance to monitor the control room radiological environment under degraded plant conditions; improving protective action guidelines to better protect control room personnel; adding instructions to evacuate non-essential personnel in order to assure sufficient breathing apparatus for essential control room personnel; upgrading the scott air packs from the current Scott IIa to the newer 4.5 versions; and, a plan to include in a subsequent operator training cycle to have operators wear respiratory equipment during training at the simulator to demonstrate the ability to safely operate the plant under degraded conditions.

On September 18, 1996, the licensee identified additional discrepancies in the assessment of control room habitability, as documented in ACR 96-1063. The deficiency was identified by the configuration management group during reviews to upgrade the licensing and design basis for the plant. The licensee found that no calculations existed for the control room dose with the existing as-built ventilation system, and no calculation existed to support the adequacy of the use of self-contained breathing supplies to ensure control room habitability during design a basis accident. This finding highlighted a deficiency in the licensee actions to close NUREG-0737 Item III.D.3.4 on Control Room Habitability for both Haddam Neck and Millstone 1. This item remains open pending further review by the NRC.

E8.3 (Closed) VIO 94-22-02: AFW Support Loading

This issue concerned inadequate corrective action that allowed a loss of control of the seismic qualification of a Auxiliary Feedwater Pump (AFW) piping restraint. During the installation of a new non-safety grade AFW system and associated piping CY, engineering personnel identified that the seismic restraint separating the safety grade and non-safety grade AFW piping was in an unanalyzed condition due to omission of two valves in the load analysis. The unanalyzed condition had existed for about seven days.

Once the condition was identified, immediate action was taken to break the tie between the operable and the new systems, eliminating the seismic interaction concerns. The deficiency occurred because the discipline engineer was not involved in the pre-construction walkdown review of the modification. Several previous

Plant Information Reports (PIRs) had identified similar conditions adverse to quality that involved piping supports that affected the seismic qualification of operable portions of safety related equipment.

CY attributed the cause of the event to a weakness in work controls that did not prevent the coupling of non seismically qualified modifications into existing qualified piping. The inspector reviewed the root cause evaluation for the event and corrective actions taken which included: procedural changes which included enhancements for performing pre-construction walkdown checklists, and pre-job briefings. The PIR process was replaced with the Adverse Condition Resolution Program, which promotes increased reporting of events, and conditions adverse to quality to increase the effectiveness of investigation and corrective actions and allows screening of past events to reveal similarities and past corrective actions taken. Based on the review of the completed actions, this item is closed.

E8.4 Review of LERs (VIO 96-11-08, EEI 96-11-09, EEI 96-11-10)

a. Inspection Scope (92700, 90712)

The purpose of this inspection was to review licensee event reports (LERs) to verify the requirements of 10 CFR 50.72 and 50.73 were met.

b. Observations and Findings

- LER 96-13, CAR Fan Piping Susceptible to Water Hammer

This LER concerned the operation of the plant with inoperable containment air recirculation fans. This issue was previously reviewed in Inspection 96-08. This item is closed.

- LER 96-14, Containment Sump Screens Not Sized as Expected

This LER concerned the operation of the plant with an inoperable ECCS flow path. This issue was previously reviewed in Inspection 96-08. This item is closed.

- LER 96-16, Inadequate RHR Pump NPSH

This LER concerned the operation of the plant with an inoperable ECCS flow path and the inadequate assurance that the RHR pumps would perform their design function under design basis accident conditions. This issue was previously reviewed in Inspection 96-08. This item is closed.

- LER 96-19, Pin Hole Leak on RHR Heat Exchanger Valve

This LER concerned the discovery of degraded conditions in the RHR system. The issue was previously reviewed in inspections 96-10 and 96-80, and in Section O2.1 above. This item is closed.

- LER 96-20, Fuel Transfer Tube Bellows Not Tested

  This LER concerned the discovery that a containment piping penetration had not been tested as required, as was previously reviewed in Inspection 96-08. This event is similar to another deficiency identified in the containment leakage rate program, as describe in LER 96-28 below. This item is closed.

- LER 96-21, Valve Leakage Results in Nitrogen Intrusion

  This LER concerned plant operation in Mode 5 with a nitrogen bubble in the reactor head, as was described in Inspections 96-80 and 96-10. This item is closed.

- LER 96-22, RCS Loop Stop Valves Opened Without Timely Sample

  This LER concerned the failure to obtain a timely boron sample of the reactor coolant system prior to unisolating the loops, as described in Inspection 96-80. This LER is closed.

- LER 96-24, B RHR Pump Inoperable

  This event involved the discovery on September 1, 1996 that the B RHR pump was in operable. The licensee root cause evaluation was completed on September 23, which concluded that the pump had been inoperable since it was last run on August 19, and failed on shutdown at that time. The pump failed due to a combination of original manufacturing defects and a marginal design in the tolerances of internal components in the rotating element. NRC review of the pump failure and the NRC findings relative to the event are provided in Inspection reports 96-80 and 96-10. The inspector had no further questions regarding the response actions for the event.

  The licensee determined on September 24 that the event was reportable per 50.72(a)(2)(i)(B) as operation in a condition prohibited by Technical Specification 3.4.1.4.2, since immediate action to return the pump to service was not taken during the period from August 19 to September 1. The inspector noted that the licensee did not know that the B RHR pump was inoperable prior to September 1. Nonetheless, the event was also reportable to the NRC under another 50.73 reporting criteria.

  The B RHR pump was operated intermittently as needed for decay heat removal following the plant shutdown on July 22, 1996 until the pump failed when shutdown on August 19. The design basis for the pump following a design basis event is to operate for an indefinite period (generally greater than 30 days) in the long term recirculation mode following a postulated loss of coolant accident. Due to the inherent manufacturing defects and marginal design, the pump was in capable of performing its design function had the plant experienced a design basis event prior to the shutdown on July 22. Thus, the event was reportable under 50.73(a)(2)(ii)(B) as a condition that resulted in the plant being operated outside the design basis. The NRC reporting guidance in NUREG 1022, Revision 1 for

50.73(a)(2)(ii) states (on page 37) that an example of a condition that is reportable is the discovery that one train of a required two train safety system has been incapable performing its design function for an extended period of time during operation. This would be considered operation outside the design basis because for an extended period of time, the system did not have suitable redundancy.

As such, the failure of the B RHR pump was also reportable to the NRC under 10 CFR 50.72(b)(1)(ii) and a one (1) hour notification to the NRC Operations Center should have been made when the root cause analysis and reportability reviews were completed on September 24, 1996. The failure to make the required notification was a violation of 10 CFR 50.72 **(VIO 96-11-08)**.

- LER 96-26, Weld Flaws in SFP SW Piping

  This LER concerned the discovery of degraded pipe and pipe welds in the service water piping supplying cooling to the spent fuel cooling system, as described in section M.2.2 above. The preliminary root cause evaluation was that a lack of root weld penetration and poor weld fitup contributed to the weld flaws. A failure analysis was planned to determine the cause of the weld degradation, and the results reported in a supplemental LER. The licensee's safety assessment of all defects concluded that the spent fuel pool cooling function was not compromised. This LER is closed.

- LER 96-27, Boron Injection Flow Path Below Minimum Temperature

  During reviews on October 8 to assure plant system readiness to enter Mode 6, a system engineer identified discrepancies with the temperature instruments (in panel HT-BA-PNL-A&B) used to perform surveillances per Technical Specification 4.1.2.1.a on the heat traced portion of the boron injection flow path. The instruments are used per TS 4.1.2.1.a to verify that the heat traced portion of the flow path was above 140 degrees F when a flow path from the boric acid path was used. The discrepancy was that the temperature instruments had not been subject to periodic calibration.

  The licensee used portable instruments to verify the accuracy of the instruments. On October 10, the licensee identified certain locations in the boron injection flow path in which the temperatures were below the TS required minimum of 140 degrees F, which rendered the associated portions of the boration system inoperable. The licensee measured temperatures as low as 120 F in the gravity feed line to the metering pump, and 90 F at the suction of the charging pumps at the junction of the discharge from the boric acid pumps. This adverse condition was addressed in ACR 96-1196. The licensee reported this event as plant operation outside the licensing basis, and past plant operations in a condition contrary to the technical specifications.

  The cause of this event was inadequate design of control circuits used to monitor flow path temperatures and energize heat trace circuits as necessary to maintain minimum temperature. The licensee also failed to provide an adequate surveillance program to assure the instruments relied upon to meet TS requirements were accurate. The design used heat trace circuits with 9 watts per foot and 6 watts per foot cable. Temperature detectors used to energize the heat trace circuits were located near the high power heat trace cable, which also controlled the low power circuits. Further, the licensee found that the temperature detectors were not placed in the optimum locations that would assure the coolest portions of the circuit remained above the 140 F limit. Finally, the event indicated ineffective corrective action in response to Inspection Item 93-01-01, in that the licensee took action to assure that instruments used to satisfy TS surveillance requirements were periodically calibrated. The actions at that time failed to identify the present deficiencies.

The purpose of the heat trace circuits was to assure the fluid in the boron injection flow path remained above the solubility temperature and thus preclude precipitation of the high concentration (as high as 22,500 ppm) boric acid. Despite the deficiencies in the heat trace circuit design and calibration, the affected flow paths remained operable as demonstrated by a recent test (SUR 5.1-146 in August 1996) and operations that passed water through the associated piping. This discrepancy had no impact on analyzed accidents. UFSAR Section 15.2.3 describes the licensee's analysis of the inadvertent boron dilution event. The accident analyses only credits the use of alarms and monitors to detect the dilution and then manual operator action to terminate the event prior to the loss of shutdown margin. Thus, the safety consequences of the boric acid heat trace discrepancy was low.

The licensee took actions to: (i) assure a boration flow path was operable per TS 3.1.2.1 for operation in Mode 5 and 6 (the flow path from the refueling water storage tank was used); (ii) restore the gravity feed flow path to an operable status prior to core offload operations by replacing the higher wattage cables with low wattage cable; and (iii) revise procedures to enhance the periodic monitoring of heat trace circuits with hand held digital probes.

Plant operation with heat trace circuits in the boron injection flow path less than 140 degrees F was contrary to Technical Specification 3.1.2.1 and 3.1.2.2. **(EEI 96-11-09)**.

- LER 96-28, Containment Air Lock Hydraulics Not Leak Rate Tested

During a review of a proposed modification of the containment personnel air lock hydraulic system, the licensee identified on October 16 that penetration CN-2 did not meet the requirements of 10 CFR 50 Appendix J and had never been Type B leak rate tested. The licensee reported this event as a condition that would have resulted in the plant operating in an unanalyzed condition, and as a condition that alone could have prevented the fulfillment of a safety function needed to mitigate an accident.

The hydraulic system penetrates the primary containment boundary as a non-seismic, non-QA system with no isolation provision for penetration CN-2. Although the hydraulic hoses and seals are tested as part of the air lock Type B test and the containment Type A test, the oil reservoir was not vented to atmosphere during those tests and therefore, the past leak rate tests would not have verified the pressure integrity of the hydraulic system. During a postulated design basis LOCA, the containment atmosphere pressure would displace the hydraulic fluid through the inner hydraulic seals and fittings, through the tubing inside the airlock, and then escape from the containment through the outer mechanical seals and fittings. This pathway would allow an untreated leakage path of containment atmosphere to the environment. The licensee's assessment was that this condition had low safety significance because, although the potential leak path existed, the amount of leakage would be greatly reduced by the restrictions provided by the components in the system, the tortuous path for release, and the resistance provided by the hydraulic fluid.

Section II.G of 10 CFR 50, Appendix J defines Type B tests as tests intended to measure leakage across leakage limiting boundary for primary reactor containment penetrations, including piping penetrations. Technical Specification 4.6.1.2 implements the requirements of 10 CFR 50, Appendix J. Technical Specification 4.6.1.2.d states that containment leakage rates shall be demonstrated in conformance with the criteria in Appendix J of 10 CFR 50, and that Type B tests shall be conducted at intervals to greater than 24 months and at a pressure not less that Pa, 39.6 psig. The failure to test the containment penetration CN-2 using a Type B test to measure the leakage is an apparent violation of 10 CFR 50, Appendix J, and Technical Specification 4.6.1.2.d (**EEI 96-11-10**). The inspector noted that this violation was similar to the failure to test penetration P-50 (reference Inspection Item 96-08-08 and LER 96-20).

c. Conclusions

The events reported by the licensee provided additional examples of discrepancies in the design and licensing basis, deficiencies in translating the licensing basis into practice, in reduced margins for shutdown operations and SFP cooling, inadequate reporting of plant events, and ineffective corrective actions.

IV. Plant Support

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope

The inspector reviewed the security program during the period of September 23-26, 1996. Areas inspected included: effectiveness of management control; management support and audits; protected area detection equipment; alarm stations and communication; testing, maintenance and compensatory measures; and training and qualification. The purpose of this inspection was to determine whether the licensee's security program, as implemented, met the licensee's commitments and NRC regulatory requirements.

b. Observations and Findings

Management support is ongoing as evidenced by the timely completion of the vehicle barrier system and the installation of the biometrics hand geometry system to provide more positive plant access control. Alarm station operators were knowledgeable of their duties and responsibilities, security training was being performed in accordance with the NRC-approved training and qualification plan and the training were well documented and available for review. Management controls for identifying, resolving, and preventing programmatic problems were effective and noted as a programmatic strength.

Protected area (PA) detection equipment satisfy the NRC-approved physical security plan (the Plan) commitments and security equipment testing was being performed as required in the Plan. Maintenance of security equipment was being performed in a timely manner as evidenced by minimal compensatory posting associated with non-functioning security equipment, and maintenance documentation weaknesses noted during the previous inspection had improved.

c. Conclusions

The inspector determined that the licensee was implementing a security program that effectively protects public health and safety. Weaknesses noted during the previous inspection, conducted in October 1995, in the area of training and maintenance documentation, had been corrected.

S2 Status of Security Facilities and Equipment

S2.1 Protected Area Detection Aids

a. Inspection Scope

The inspector conducted a physical inspection of the PA intrusion detection systems (IDSs) to verify that the systems were functional, effective, and met licensee commitments.

b. Observations and Findings and Conclusions

On September 23, 1996, the inspector determined by observation that the IDSs were functional and effective, and were installed and maintained as described in the Plan.

S2.2 Alarm Stations and Communications

a. Inspection Scope

Determination whether the Central Alarm Station (CAS) and Secondary Alarm Station (SAS) are: (1) equipped with appropriate alarm, surveillance and communication capability, (2) continuously manned by operators, and that (3) the systems are independent and diverse so that no single act can remove the capability of detecting a threat and calling for assistance, or otherwise responding to the threat.

b. Observations, Findings and Conclusions

Observation of CAS and SAS operations verified that the alarm stations were equipped with the appropriate alarm, surveillance, and communication capabilities. Interviews with CAS and SAS operators found them knowledgeable of their duties and responsibilities. The inspector also verified through observation and interviews that the CAS and SAS operators were not required to engage in activities that would interfere with the assessment and response functions, and that the licensee had exercised communications methods with the local law enforcement agencies as committed to in the Plan.

S2.3 Testing, Maintenance and Compensatory Measures

a. Inspection Scope

Determination whether programs were implemented that will ensure the reliability of security related equipment, including proper installation, testing and maintenance to replace defective or marginally effective equipment. Additionally, determination whether security related equipment failed, the compensatory measures put in place was comparable to the effectiveness of the security system that existed prior to the failure.

b. Observations and Findings

Review of testing and maintenance records for security-related equipment confirmed that the records were on file, and that the licensee was testing and maintaining systems and equipment as committed to in the Plan. During the previous inspection conducted October 2-6, 1995, several instances were identified where equipment had been repaired for months, but the maintenance documentation needed to close out the work request had not been completed. The inspector determined based on a review of security equipment maintenance records, including open work requests, and discussions with security management, that actions taken to address the problem were effective. A priority status was assigned to each work request and repairs were normally being completed within 24 hours from the time a work request, necessitating compensatory measures, was generated.

c. Conclusions

Security equipment repairs were being completed in a timely manner and maintenance documentation problems were corrected. The use of compensatory measures was found to be appropriate and minimal.

S5 Security and Safeguards Staff Training and Qualification

a. Inspection Scope

Determination whether members of the security organization were trained and qualified to perform each assigned security related job task or duty in accordance with the NRC-approved training and qualification (T&Q) plan.

b. Observations and Findings

The inspector selected at random and reviewed the training, physical, and firearms qualification/requalification records of ten security force members (SFMs).

During the previous inspection, conducted October 2-6, 1995, the inspector noted several training records which had anomalies, involving lapses in SFM certification, for which there were no clear explanations recorded. Some files contained an explanatory memorandum indicating that the lapse was due to an extended period of leave, but few were dated, or contained details. To address the concern, the training department reviewed the documentation process and took appropriate action. No unexplained anomalies were identified during the inspector's review of the randomly selected training records. Additionally, the inspector interviewed a number of SFMs to determine if they possessed the requisite knowledge and ability to carry out their assigned duties.

c. Conclusions

The inspector determined that the training had been conducted in accordance with the T&Q plan, and that it was properly documented. Based on the SFMs responses to the inspectors' questions, the training provided by the security training staff was effective.

S6 Security Organization and Administration

a. Inspection Scope

A review of the level of management support for the licensee's physical security program was conducted.

b. Observations and Findings

The inspector reviewed various program enhancements made since the last inspection, which was conducted in October 1995, with security management. These enhancements included the timely completion of the vehicle barrier system installation, procurement and installation of the hand geometry/biometrics system to provide more positive plant access, installation of new closed circuit monitors in the CAS/SAS to improve observation of PA barrier, and the allocation of monetary resources for additional training initiatives and improvements. Additionally, the inspector reviewed shift rosters, organizational charts, and payroll records to determine if the security force was adequately staffed and if SFM's were working excessive hours due to low manning. The inspector determined based on the results of the document reviews and discussions with licensee and contractor supervision, and SFMs that manning levels were adequate and overtime was being properly controlled.

c. Conclusions

Management support for the physical security program was determined to be excellent.

S7 Quality Assurance in Security and Safeguards Activities

S7.1 Effectiveness of Management Controls

a. Inspection Scope

A review of the licensee's controls for identifying, resolving and preventing programmatic problems was conducted.

b. Observations and Findings

The inspector determined that the licensee had controls for identifying, resolving, and preventing security program problems. These controls included the performance of the required annual quality assurance (QA) audits, a formalized self-assessment program, and ongoing shift oversight by supervisors. The licensee also utilized industry data, such as violations of regulatory requirements identified by the NRC at other facilities, as a criterion for self-assessment.

c. Conclusions

A review of documentation applicable to the programs indicated that initiatives to minimize security performance errors and identify and resolve potential weaknesses were being implemented and were effective.

S7.2 Audits

a. Inspection Scope

The inspector reviewed the licensee's audit of the security program to determine if the licensee's commitments as contained in the NRC-approved physical security plan were being satisfied.

b. Observations and Findings

The inspector reviewed the 1995 QA audit of the security program conducted between September 6 - November 1, 1995, (Audit No. A25109). The inspector determined that the audit was conducted in accordance with the Plan and that the results were distributed to appropriate levels of management. The audit identified three findings, two unresolved items and one recommendation. The audit findings addressed potential weaknesses in record retention, lock and key control and key card record accountability. The inspector determined that the noted findings were not indicative of programmatic weaknesses or noncompliance with regulatory requirements, but would enhance program effectiveness. The inspector also determined, based on discussions with security management and a review of the responses to the findings, that the corrective actions were effective.

c. Conclusions

The review concluded that the audit was comprehensive in scope and depth, that the findings were appropriately distributed and that the programs were being properly administered.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Fire Protection System Valve Flange Cracks

a. Inspection Scope

The inspection scope was to evaluate licensee compensatory actions in response to fire suppression system corrective maintenance.

b. Observations and Findings

On October 18, 1996, maintenance mechanics were replacing fire system valve FP-V-123. During the torquing of the fasteners for the threaded cast iron flange, the flange cracked. The licensee replaced the cast iron flange and restored the fire header back to service on October 22, 1996. The inspector noted that the mechanics were not provided any specific guidance on the maximum torque specification for the cast iron flange.

On October 21, the inspector confirmed tag clearance 96-1011 provided adequate isolation and protection to the workers in the fire protection system. Additionally, the inspector confirmed that the licensee was appropriately implementing compensatory measures in the technical requirements manual sections II.1.C.3.1.a, and II.1.g.3.1.

c. Conclusions

The inspector noted that mechanics were not provided specific guidance on the maximum torque for fasteners on a threaded cast iron flange. Appropriate technical requirements manual compensatory actions were taken.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 27, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X4 Review of Updated Final Safety Analysis Report (UFSAR)

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and parameters to the UFSAR description. The inspector reviewed licensee activities for conformance with the UFSAR as described in Sections 15.5.2.2 (detail M1.2) and Section 9.1 (detail E2.5). Discrepancies in meeting Section 15.5.2.2. are described in detail M1.2 above.

Since the UFSAR does not specifically include security program requirements, the inspector compared licensee activities to the NRC-approved physical security plan, which is the applicable document. While performing the inspection discussed in this report, the inspector reviewed Section 6.8 of the Plan, Revision 30, dated February 29, 1996, titled, "Keys, Locks, Combinations, and Related Equipment" and performed an inventory of the key storage cabinets using the licensee's lock and key control procedure. The review disclosed that security keys and locks were being maintained and controlled in accordance with the Plan and security program procedures.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Jere LaPlatney, Unit Director
Gerry Waig, Maintenance Manager
Jack Stanford, Operations Manager
James Pandolfo, Security Manager
Ron Sachatello, Radiation Protection Manager
Tom Cleary, Sr. Licensing Representative
George Townsend, Engineering
Robert McCarthy, Engineering
David Bazinet, Instrumentation and Controls
D. Parker, Safety Analysis
M. Kai, Safety Analysis
Madison Long, Technical Support

NRC

Stephen Dembek, Haddam Neck Project Manager

INSPECTION PROCEDURES USED

IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 60710:	Refueling Activities
IP 62703:	Maintenance Observation
IP 64704:	Fire Protection Program
IP 71707:	Plant Operations
IP 73051:	Inservice Inspection - Review of Program
IP 73753:	Inservice Inspection
IP 83729:	Occupational Exposure During Extended Outages
IP 83750:	Occupational Exposure
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPEN, CLOSED, AND DISCUSSED

Open

96-11-01	EEI	Failure to Have EOP for Fuel Drop Accident
96-11-02	EEI	Ineffective Corrective Actions for Inventory Control
96-11-03	EEI	Inoperable SFB Ventilation System
96-11-04	EEI	Inadequate Instrument Setpoint Calculations
96-11-05	EEI	Inadequate Corrective Actions for Instrument Failures
96-11-06	EEI	Inadequate PAB flood Protection
96-11-07	URI	SFPCS Single Failures
96-11-08	VIO	Inadequate Reporting of RHR Pump Failure
96-11-09	EEI	Inoperable Boric Acid Heat Trace Instruments
96-11-10	EEI	Containment Penetration Not Type B Tested

Closed

96-04-01	URI	May 23 Spent Fuel Event
95-02-03	IFI	Refueling Equipment Failures
94-22-02	VIO	AFW Supports

Discussed

96-02-03	URI	Control Room Habitability
96-01-03	URI	RVLIS Design Basis
93-01-01	IFI	Instrument Calibrations

ATTACHMENT A

Procedures Revised

*ODI-190, RCS Inventory in Modes 5 and 6
*ODI-193, Pre-Evolution Briefings
*NOP 2.6-11, Makeup to RCS During Modes 5 and 6
ODI-191, Shutdown Risk Awareness
ANN 4.24-1, Cavity High Level
ANN 4.24-2, Cavity Low Level
ANN 4.24-3, Reduced Inventory Low Level
ANN 4.24-4, Ultrasonic Low Level
*NOP 2.6-12, Draining the RCS in Modes 5 and 6
NOP 2.6-1A, Mode 5 or Mode 6 RCP Seal Water Supply
*NOP 2.6-9B, Recirculation of 1B Charging Pump on the RWST
AOP 3.2-31A, Reactor Coolant/Refueling Cavity Leak
NOP 2.3-5, Refueling Operations
NOP 26-2, Chemical and Volume Control System Operation
WCM 1.2-9, Outage Planning, Scheduling, and Implementation
WCM 2.2-8, Control of Heavy Loads
WCM 2.2-7, PAB/Pipe Trench Floor Block Lifting Procedure
NOP 2.0-1, Shift Relief and Turnover
NOP 2.0-2, Shift Supervisors Operating Log
NOP 2.3-4, Shutdown from Hot Standby to Cold Shutdown
NOP 2.9-3, Refueling Cavity Filling
NOP 2.13-5A, Tracking/Establishing Modified Containment Integrity/Containment Closure
*AOP 3.2-63, Fuel Handling Accident
AOP 3.2-31A, Reactor Coolant System Leak/Refueling Cavity Leak (Mode 5 and 6)

* - indicates new procedures

LIST OF ACRONYMS USED

ACP	Administrative Control Procedure
ACR	Adverse Condition Report
AEC	Atomic Energy Commission
AEOD	Office for Analysis and Evaluation of Operational Data
ALARA	As Low As Is Reasonably Achievable
ANN	Annunciator Response Procedure
ANSI	American National Standards Institute
AOP	Abnormal Operating Procedure
ASME	American Society of Mechanical Engineers
AWO	Authorized Work Order
CAR	Containment Air Recirculation
CAS	Central Alarm Station
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CLIS	Cavity Level Indication System
CMP	Corrective Maintenance Procedure
CVCS	Chemical and Volume Control System
CY	Connecticut Yankee
CYAPCo	Connecticut Yankee Atomic Power Company
EA	Escalated Action
EDG	Emergency Diesel Generator
ENG	Engineering Procedure
EOP	Emergency Operating Procedure
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
ESF	Engineered Safety Feature
F	fahrenheit
gpm	gallons per minute
HECA	High Efficiency Charcoal Air
HEPA	High Efficiency Particulate Air
I & C	Instrument & Control
IDP	Ingersol Dresser Pump
IDS	Intrusion Detection Systems
IPAP	Integrated Performance Assessment Process
IR	Inspection Report
IRT	Independent Review Team
ISI	In-Service Inspection
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
MOV	Motor Operated Valve
MTE	Measuring & Test Equipment
NOP	Normal Operating Procedure
NCV	Non-Cited Violation
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission

NSO	Nuclear Side Operator
ODI	Operations Department Instruction
OJT	On the Job Training
PA	Protected Area
PAB	Primary Auxiliary Building
PIR	Plant Inspection Report
PMP	Preventive Maintenance Procedure
PORC	Plant Operations Review Committee
PORV	Power Operated Relief Valve
ppm	parts per million
PPR	Plant Performance Review
psig	pounds per s quare inch
QA	Quality Assurance
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RFO	Refueling Outage
RPWST	Recycle Primary Water Storage Tank
RWST	Refueling Water Storage Tank
SAS	Secondary Alarm Station
SFB	Spent Fuel Building
SFM	Security Force Members
SFP	Spent Fuel Pool
SRO	Senior Reactor Operator
ST	Special Test Procedure
SUR	Surveillance Procedure
SW	Service Water
T&Q	Training and Qualification
TPC	Temporary Procedure Change
TRM	Technical Requirement Manual
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
VIO	Violation
VP	Vendor Procedure
WCC	Work Control Center
WCM	Work Control Manual