U.S. NUCLEAR REGULATORY COMMISSION

Region I

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Report No.:	50-333/96-07
Licensee:	New York Power Authority
Facility:	James A. FitzPatrick Nuclear Power Plant
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Dates:	September 29, 1996 through November 16, 1996
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EXECUTIVE SUMMARY

James A. FitzPatrick Nuclear Power Plant
NRC Inspection Report No. 50-333/96-07

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report includes the results of routine health physics, inservice inspection, and engineering inspections by Region I inspectors.

Operations

- The shutdown for the refueling outage was safe and well controlled. Good command and control, communication and procedure adherence were noted.

- Overall, defueling operations were conducted safely and in accordance with procedures. Communications were good and the verification of bundle location and orientation was properly performed. An exception to good performance was that, during fuel movement, the grapple switch was inadvertently operated. This mis-operation was not initially brought to the attention of the refuel bridge senior reactor operator which delayed initiation of appropriate corrective action to install a cover over the switch.

Maintenance

- A personnel error which resulted in the incorrect identification of CRDs to be removed was compounded because a second check failed to recognize the error. In addition, unexpected conditions and indications related to the position indication probes and hydraulic control unit vent valve maintenance were not adequately pursued which contributed to the incorrect exchange of three CRDs. The failure to accurately locate CRDs for exchange is a violation **(VIO 50-333/96007-01)**.

- During control rod blade replacement, while withdrawing the combined grappling tool, a fuel support piece (FSP) was inadvertently withdrawn and subsequently became lodged in the control rod blade guides several feet above the core plate. Fuel handlers exhibited poor work practices by failing to ensure that the FSP was not attached to the tool. In addition, the procedure did not provide direction to check the handling tool when raising it. The refueling SRO demonstrated good work practices by recognizing that the fuel support piece was stuck. The fuel support piece recovery evolution was well planned and conducted carefully.

- The inservice inspection (ISI) program was well documented, controlled and implemented. The program manager demonstrated good knowledgeable of ISI requirements and good internal communications were noted. A licensee developed checklist was an improvement over previous controls to ensure that ISI requirements were met. NYPA has good oversight of the NDE subcontractor and NDE examinations.

- Nondestructive examination (NDE) was performed in accordance with requirements. The licensee NDE Level III oversight of the NDE subcontractor was an effective means to identify missed indications and/or defects.

Executive Summary (cont'd)

Engineering

- Overall, the installation and pre-operational test for the decay heat removal (DHR) system were acceptable. Original calculations for the DHR system heat removal capacity were not thorough in that the calculations did not account for the additional circulation provided by the control rod drive and reactor water cleanup systems remaining in service during the preoperational test.

- Design control weaknesses were identified that included the use of unverified assumptions, engineering judgements, and input data for the safety-related station batteries modification; reactor protection system/electrical protection assembly (RPS/EPA) undervoltage trip calibration; an evaluation of moderate energy break in the DHR piping; analysis of the DHR system performance; and assessment of the combined decay heat load of the Reactor Core and Spent Fuel Pool during refueling outages. **(VIO 50-333/96007-03)**

- Inadequate acceptance criteria were used for the battery service tests and RHRSW inservice tests. **(VIO 50-333/96007-04)**

- A failure to utilize the temporary modification process to install a temporary HEPA filter/blower in the "A" RHR Heat Exchanger room resulted in a violation of 10 CFR 50.59. **(VIO 50-333/96007-05)**

- Frompt corrective action was not taken to correct deficiencies associated with residual heat removal system design basis documentation verification, and the average power range monitor flow bias trip calibration period. **(VIO 50-333/96007-06)**

- The inspectors identified a potential weakness in the depth of reviews performed as part of the Engineering Assurance (EA) initiative. An inspector followup item was opened pending review of phase II of the EA assessment of modification quality. **(IFI 50-333/96007-07)**

Plant Support

- Significant improvements were noted in radiological worker and radiation protection technician performance. Significant attention has been focused on radiological worker performance, and several licensee initiatives in this area were observed. However, one violation concerning proper high radiation area entry was identified. **(VIO 50-333/96007-08)**

- The licensee's program for assurance of quality in the radiation protection program is generally very effective. However, one violation regarding corrective action effectiveness in the radioactive shipping program was identified **(VIO 50-333/96007-09)**.

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Report Details

Summary of Plant Status

The plant was taken off line on October 26, 1996 to begin the scheduled refueling outage. The alternate decay heat removal system (ADHR) was placed in service to provide for decay heat removal. In addition to refueling, major activities planned to be completed include replacement of service water piping, main steam isolation valve repair, replacement of control rod drive mechanisms and main turbine work.

I. Operations

O1 Conduct of Operations

O1.1 Power Reduction and Shutdown

a. Inspection Scope (71707)

The inspectors witnessed various portions of the shutdown preparations, power reduction, and reactor cooldown and depressurization activities. The inspectors' objective was to determine the effectiveness of management controls in ensuring a safe transition to shutdown.

b. Observations and Findings

The unit was shutdown per operating procedure (OP)-65, Start-up and Shutdown Procedure. Power reduction was performed in accordance with reactor analyst procedure RAP-7.3.16, Plant Power Changes, and the main generator was removed from service on October 26, in accordance with applicable operating procedures. The unit was in cold shutdown at 10:40 p.m. and the reactor mode switch was taken to the refuel position at 11:33 p.m. on October 26.

The inspectors noted good command and control of unit shutdown activities. Communications were professional and precise with three-point communications used. Coordination of various shut down activities by licensed operators was very good. Appropriate oversight of personnel during manipulation of the reactor controls was noted. For example, a second checker for control rod motion and selection was stationed. In addition, senior licensee management personnel were assigned for shift coverage.

c. Conclusions

The shutdown for refueling outage number 12 was safe and well controlled. Good command and control, communication and procedure adherence were noted.

O1.2 Refueling Operations

a. Inspection Scope

The inspectors observed defueling operations in accordance with reactor analyst procedure (RAP)-7.1.04B, Spiral Offload/Onload Refueling Procedure, to verify that refueling operations were being performed safely and in

compliance with technical specifications. The inspectors observed refueling operations from both the control room and the refueling bridge. Additionally, various refueling prerequisites were reviewed.

b. Observations and Findings

The fuel moves were conducted by a contractor with licensed operators providing oversight and verification on both the refuel bridge and in the control room. The licensee utilized a computerized fuel move tracking system in the control room to provide an additional verification of correct fuel moves. Several issues resulted in delays of the defueling operations and are discussed below:

During the initial core off-load, the fuel handlers were somewhat hindered in moving fuel because of the effect of thermoclines in the vessel cavity water which made visual verification of in-vessel work difficult. These thermoclines were different than those observed in past refueling outages because of the operation of the alternate decay heat removal (ADHR) system. The thermoclines were caused by the mixing of the cooler ADHR water coming into the reactor cavity and the hotter water exiting the vessel cavity.

On two occasions the refueling bridge had minor maintenance problems which delayed fuel movements for several hours.

On November 4, the refuel bridge operator had completed lowering a bundle into the spent fuel pool and after the proper verifications of bundle location he operated the grapple open/close switch to the open position; however the closed lamp was illuminated. This was unexpected as the intended operation was for the grapple to open. The operator then recognized that the switch was operated in the wrong position (which may have been the result of bumping the switch during the lowering of the bundle into the rack). This information was not immediately brought to the attention of the refueling senior reactor operator (SRO), but a request for a switch cover was made. Fuel moves were continued with a different fuel handler. On the following shift the fuel handlers secured moving fuel until a switch cover could be installed and licensee management was notified of the misposition of the switch. Following the installation of a temporary modification to provide a cover for the grapple switch defueling was resumed. A critique was held the next day to discuss the event. Corrective actions included operations management briefing the refueling crews on expectations with regard to the importance of raising safety issues and concerns.

c. Conclusions

Overall, defueling operations were conducted safely and in accordance with procedures. With the exception of not immediately communicating the mis-operation of the grapple switch to the refuel bridge SRO, communications were good. The verification of bundle location and orientation was properly performed.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following systems:

- Emergency Diesel Generator
- Alternate Decay Heat Removal
- Fire Protection System
- Portions of Containment System

Equipment operability, material condition, and housekeeping were acceptable.

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:

•WR 95-07511	perform discharge testing of B station
•WR 96-05107	adjust/repair butterfly valves in DHR system
•WR 96-05258	perform preventive maintenance on 4160 breaker
•WR 95-06497	replace service water isolation valve
•WR 95-04678	minor inspection high pressure coolant injection (HPCI) turbine and pump
•WR 95-06137	repair HPCI turbine steam supply valve
•WR 95-07840	replace HPCI booster pump mechanical seal

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned task. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures were in place.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed and reviewed portions of ongoing and completed surveillance tests to assess performance in accordance with approved procedures

and Limiting Conditions for Operation, removal and restoration of equipment, and deficiency review and resolution. The following tests were reviewed:

- ST 24D — reactor core isolation cooling (RCIC) automatic isolation logic system functional and simulated automatic actuation test
- ST 24F — RCIC System inoperable test
- ISP-B1 — RCIC auto isolation instrument functional test
- ST-9D — emergency diesel generator (EDG) test
- ST-18 — main control room emergency fan and damper operability test

b. Observations and Findings

The licensee conducted the above surveillance appropriately and in accordance with procedural and administrative requirements. Good coordination and communication were observed during performance of the surveillance.

M1.3 Conclusions on Conduct of Maintenance

Overall, maintenance and surveillance activities were well conducted, with good adherence to both administrative and maintenance procedures.

M1.4 Incorrect Control Rod Drive Removal

a. Inspection Scope

As a result of personnel error, the incorrect control rod drives (CRDs) were exchanged during the CRD exchange. The inspectors reviewed the event and observed the event critique and meetings. The licensee's recovery plan was reviewed and subsequent CRD exchanges were observed.

b. Observations and Findings

During the preparation for the CRD exchange, the CRDs designated for exchange were not marked correctly which resulted in the unintentional exchange of three CRDs. The first two CRDs exchanged were the wrong drives because of the temporary labelling error. When removing the third drive, workers did not exchange the drive that they were intending to remove which was an additional error. This occurred because the removal tool was lined up to the wrong CRD. Following the third CRD exchange, the CRD exchange work was stopped due to excessive leakage observed at the high point vents during work conducted on the hydraulic control units (HCUs) in parallel with the CRD exchange evolution.

In parallel with the CRD replacement, work was being conducted on hydraulic control unit vent valves. Problems with draining the vent lines were occurring which prompted additional investigation and led to the identification of the above error. Operators had questioned the excess water and had the contractor reverify that they were working on the correct CRD during the first two CRD exchanges. After excessive water flow was observed from the vent valve during the exchange of the third CRD, the shift manager stopped work.

MP-004.03, CRD Removal and Replacement, describes removal and replacement of control rod drives. The procedure requires that all CRDs to be removed are accurately located and readily identified (marked) prior to removal. During the work preparation phase, the wrong CRDs had been identified for removal. The error occurred because the CRDs to be changed out had been improperly identified and the second check failed to recognize the identification tagging error. To identify which CRDs were to be removed, the contractor had used a core map and used the undervessel doorway as a reference point. Licensee review concluded that the core map was oriented incorrectly. There were other opportunities to have identified the problem sooner. First, it was noted that there was some discussion among vendor personnel concerning labels on the position indication probes (PIP) (which was an indication that the CRDs had been improperly identified), but this was not brought to the attention of licensee management and was thought to be a PIP label error. Additionally, there were inconsistent indications of whether a rod was uncoupled based on the uncoupling tool results. These indications were documented by Engineering, but they failed to identify the fact that multiple rods were still coupled and thus recommended that the CRD work proceed. The licensee continued the CRD exchange for the CRDs which had positive indication that they were uncoupled while continuing to evaluate the questionable results. Also, as described above, excess water from the HCU was not evaluated until the third CRD had been exchanged.

c. Conclusions

A personnel error which resulted in the incorrect identification of CRDs to be removed was compounded because a second check failed to recognize the error. In addition, unexpected conditions and indications related to the PIPs and HCU vent valve maintenance were not adequately pursued which contributed to the incorrect exchange of three CRDs. The failure to accurately locate CRDs for exchange is a violation **(VIO 50-333/96007-01)**.

M1.5 Stuck Fuel Support Piece

a. Inspection Scope

The inspectors observed control rod blade replacement and followed up on a stuck fuel support piece which occurred during control rod blade replacement activities.

b. Observations and Findings

On November 14, while conducting control rod blade replacements, a fuel support piece (FSP) became lodged between two blade guides and was suspended several feet above the core plate. At the time all fuel was off loaded and in the spent fuel pool. Blade replacement activities had just been placed on hold by the refueling senior reactor operator because of difficulties encountered with engaging the combined grappling tool in the FSP.

The inspector attended the licensee's critique of the event and learned that the most likely cause of the FSP becoming lodged in the blade guides above the core plate was the result of the combined grappling tool becoming stuck in the FSP while

withdrawing the tool. The fuel handlers stated that the clearances between the grappling tool and the FSP flow orifices were very tight and as a result may have caused the FSP to remain on the tool as it was being withdrawn. As the tool was being withdrawn out of the vessel, the FSP became lodged between the adjacent control rod blade guides. The fuel handlers did not notice anything abnormal while removing the grappling tool. Subsequent to recommencing the control rod blade moves, the relieving SRO noted that the fuel support piece was not in the normal position.

The licensee generated a temporary operating procedure, TOP-241, Cell 34-07 Fuel Support Piece Recovery, to utilize a nylon rope and handling poles to reseat the FSP. Following the recovery, the procedure also addressed visual inspection of the FSP in the spent fuel pool lay down area, and inspection of the affected blade guides and adjacent in-core instruments. The FSP was successfully recovered and inspections indicated that there was no apparent damage.

c. Conclusions

While withdrawing the combined grappling tool, the fuel handlers exhibited poor work practices by failing to ensure that the FSP was not attached to the tool. In addition, the procedure did not provide direction to check the handling tool when raising it. The refueling SRO demonstrated good work practices by recognizing that the fuel support piece was stuck. The fuel support piece recovery evolution was well planned and conducted carefully.

M1.6 Inservice inspection (ISI) Program Review

a. Inspection Scope (73753)

The inspectors assessed the ISI program, related nondestructive examination (NDE) activities, and the implementation of the ISI program. Included in the review were the ISI NDE procedures and the certification of the NDE personnel. The review included ultrasonic testing (UT), liquid penetrant testing (PT), magnetic particle testing (MT) and radiographic testing (RT) procedures.

b. Observations and Findings

The licensee is in the third inspection period of the second inspection interval, as described in the American Society of Mechanical Engineers (ASME) Code, Section XI. The ASME Code requires 100% of the scheduled ASME Class 1, 2 & 3 inspection items to be completed by the end of the inspection interval. At FitzPatrick, the 1996 refueling outage is the last outage in the second inspection interval.

The licensee extended the second inspection interval 14 months due to an extended shutdown, and an additional nine months, as described in the ASME Code, Section XI, IWA-2430. The extended inspection interval did not effect the intergranular stress corrosion cracking (IGSCC) inspection program, which is defined in Generic Letter 88-01, nor the commitment to the NRC to perform ultrasonic (UT) examination and evaluation of the indications in the reactor vessel head.

The NRC issued a safety evaluation report (SER) on October 27, 1987, for the licensee's ISI plan and ASME code relief requests. Subsequent SERs were issued for disposition of relief requests dated after October 27, 1987.

The licensee utilized NDE subcontractors at FitzPatrick to perform the ISI NDE examinations. The subcontractor is responsible to submit the final data to the NYPA NDE Level III for evaluation. The NYPA NDE Level III has the final acceptance or rejection of the NDE examination and data.

The inspector verified the Authorized Nuclear Inservice Inspector (ANII) oversight of ASME Section XI NDE ISI activities. ASME Code, Section XI, IWA-2000 is a requirement for the licensee to provide the opportunity for the ANII to review the NDE procedures, NDE personnel certifications, and final data reports.

The licensee developed an ISI program checklist to aid in tracking ISI program requirements. The checklist included the component, work request, exam type, procedure, sketch identification and additional notes.

The inspector reviewed the reactor pressure vessel internal visual examination data sheet for the shroud for a weld in which some crack like indications were identified on a vertical weld. The documentation indicated that the indications were minor and that all criteria were met.

c. Conclusions

The ISI program was well documented, controlled and implemented. The program manager was knowledgeable of ISI and ASME Code requirements. There is good communication between the ISI manager, engineering and plant management. The documentation supporting the examinations was accurate and readily available for review by the inspector. The inspector reviewed the ISI program checklist which was used as a guide to ensure that all required ISI was completed. The checklist was an improvement over previous controls. NYPA demonstrated good oversight of the NDE subcontractor and NDE examinations.

M1.7 NDE Observation and Data Review

a. Inspection Scope (73753)

The scope of this inspection was to observe NDE activities and review final NDE examination data.

b. Observations and Findings

The inspectors observed the NDE subcontractor performing magnetic particle testing (MT) and ultrasonic examination (UT) on reactor core isolation cooling (RCIC) piping welds 4" W22-902-4 FW 74 and 74A. Procedures used to perform the examination were MT-FPK-100V1, Revision 0, and UT-FPK -102, Revision 0, respectively. UT of the N-9 control rod drive return nozzle was also witnessed by the NRC inspectors. The procedure used for the N-9 nozzle was GE PDI-UT-2, Revision 0. [NUREG 0619

requested boiling water reactors (BWR) licensees to examine the N-9 nozzle for IGSCC.]

The licensee's NDE Level IIIs performed an over-check (re-performance of the examination) of the UT performed by the subcontractor on RCIC welds 4" W22-902-4 FW 74 and 74A. The NYPA NDE Level III's results did not match the results of the UT examinations by the subcontractor. This discrepancy was properly addressed.

c. Conclusion

NDE was performed in accordance with the ASME Code and site NDE procedures. The NYPA NDE Level III oversight of the NDE subcontractor was an effective means to identify missed indications and/or defects. The results of the examinations were reviewed and accepted by a NYPA NDE Level III.

M7 Quality Assurance in Maintenance Activities

a. Scope

Quality assurance (QA) with regard to NDE/ISI activities was reviewed.

b. Observations and Findings

The inspectors reviewed the quality assurance (QA) oversight program as it related to the NDE activities during the outage. The licensee indicated that their approval process to allow technicians to perform NDE on-site did not include a proficiency examination. Instead, the licensee had planned to perform a surveillance or an over-check for all the technicians for each NDE method.

A matrix was developed listing all the contracted NDE technicians. The matrix would be used to document the QA surveillance or the over-check activities. Additionally, an NDE Level III reviewed and approved all the NDE data. The inspector also verified that, on the previous outage, the QA oversight matrix had been completed and that there had been a surveillance or an over-check on all the technicians.

In addition, QA lessons learned from the previous outage resulted in one request into the "Action and Commitment Tracking System" (ACTS) to review contractor procedures and equipment for consistency with the licensee's requirements prior to initiating NDE work for future outages. The inspector verified that the review had been completed.

c. Conclusions

The QA oversight program was effective and well executed. However, the inspectors noted that no guidance document existed that described the QA NDE oversight activities.

III. Engineering

E1 Conduct of Engineering

E1.1 Alternate Decay Heat Removal Installation and Start-up

a. Inspection Scope (37551)

The inspector reviewed the licensee's installation of the alternate decay heat removal system (ADHR). The inspector performed walkdowns of the system piping and pipe supports, observed welding and in process assembly of system piping, reviewed safety evaluations and quality assurance activities, and observed system functional testing.

b. Observations and Findings

Utilizing NYPA drawing FM-133A and B, the inspector verified correct valve orientation pipe configuration and weld quality for various portions of the piping system. The inspector reviewed welders qualifications and verified that welders had the proper filler material for the task they were working at various times during system construction. Welders were knowledgeable about the welding procedures.

The inspector witnessed portions of and reviewed the data for POT 32C, Decay Heat Removal System Functional Test. The intent of the test procedure was to ensure that the decay heat removal system was capable of removing the heat generated by the spent fuel in both the reactor vessel and in the fuel pool. The performance of the test consisted of placing one train of the ADHR system in service (one recirc pump, one secondary loop heat exchanger and pump, and one cooling tower operating), securing the residual heat removal (RHR) shutdown cooling system and monitoring reactor cavity as well as system temperatures. The testing was conducted by a test engineer with assistance from operations, instrument and control (I&C), radiological protection, craftsman, and senior level management personnel.

The inspector did note that during the test, the control rod drive (CRD) and reactor water clean-up (RWCU) systems were in service providing approximately 240 gallons per minute flow and the resulting core mixing. The decay heat removal system functional test was to demonstrate that the ADHR system would remove heat from the reactor cavity and the spent fuel pool using natural circulation. The inspector noted that the licensee's original calculations for the heat removal capacity did not account for the additional circulation provided by the CRD and RWCU systems, which were in service during the test. Preliminary results indicate that there is no significant change in natural circulation flow characteristics of the reactor vessel, refueling cavity and spent fuel pool (SFP) regions; however, this item will remain an inspector followup item **(IFI 50-333/96007-02)** pending NRC review of the licensee's final calculations.

c. Conclusions

Overall, the installation and pre-operational test for the ADHR system were acceptable. Original calculations for the ADHR heat removal capacity were not thorough in that the calculations did not account for the additional circulation provided by the CRD and RWCU systems remaining in service during the preoperational test.

E1.2 Electrical Engineering Analyses

a. Inspection Scope

The inspectors reviewed selected engineering calculations and analyses to evaluate the quality of engineering involvement in site activities.

b. Observations and Findings

Station Battery Calculations

The inspectors found that the direct current (dc) voltage drop analysis of Calculation No. JAF-CALC-ELEC-00426, Revision 1, dated October 16, 1992, concluded that, with a calculated "A" battery terminal voltage of 109 volts, some safety-related loads would be provided insufficient voltage. The licensee's justification for acceptance was based on the margin between the calculation assumption of 90% battery capacity and the previous performance test (MST-71.21, October 3, 1989) that demonstrated 105% capacity. No attempt was made to equate capacity margin to increased battery terminal voltage, and no action item was issued to restrict battery capacity to a value above 90%. The same calculation used a battery load profile whose critical period load was 158 amps less than the load profile contained in the battery sizing calculation (EDA-JAF-87-B01) in effect at the time. A similar error existed for the "B" battery in Calculation JAF-CALC-00427, Revision 0, dated June 4, 1992.

Battery sizing calculation, JAF-CALC-ELEC-01418, "125V DC Power System B Sizing," Revision 0, dated November 21, 1994, superseded Calculation EDA-JAF-87-B01, dated September 18, 1987, and was issued to include new loads. One load (71INV.1B) added as a result of Modification F1-89-158 increased the load by 12 amps. The modification included an electrical calculation change form (ECCF) that indicated the load increase was 2.5 kVA (20 amps). The licensee was not able to justify the smaller, 12 amp load. A similar error existed with the "A" Battery Calculation JAF-CALC-ELEC-01417, Revision 0, dated November 21, 1994.

Failure to correctly maintain the design basis of the safety-related station batteries is the first of five examples of a violation of the design control requirements of 10 CFR 50, Appendix B, Criterion III. **(VIO 50-333/96007-003)**

The same 1994 calculation used a design margin sizing correction factor of 1.0. IEEE Standard 485, "Battery Sizing," defines design margin as accounting not only for future load growth, but also for a battery that is not fully charged. Cell specific gravity affects battery capacity. The calculation used battery capacity input data

based on a fully charged cell with 1.215 specific gravity. However, the battery surveillance procedures accept a battery with an averaged specific gravity of only 1.205. This 0.010 point difference in specific gravity equates to approximately a 3% difference in capacity for a lead acid cell. Therefore, the design margin correction factor used in the calculations was not conservative.

RPS/EPA Undervoltage Trip Calibration Extension

The evaluation prepared to support a seven-month extension of the reactor protection system electrical protection assembly (RPS/EPA) calibration period was based on a calculation (JAF-CALC-ELEC-001516, Revision 0, dated April 28, 1994) that used measured voltages as input data. The work request (94-02935-00) issued for the measurements required two voltmeters which read "...as close as possible...." The accuracy of the voltmeters was not documented. The inspectors noted that the data recorded indicated that the precision of the meters was no better than 0.1 Volts.

The calculation did not compare the required and minimum expected voltages to determine margin. The inspector found that the margin (0.1 Volt) would have been negated by the precision of the meters alone, without regard to accuracy of the meters. This is the first of three examples of a violation of the test control requirements of 10 CFR 50, Appendix B, Criterion XI. **(VIO 50-333/96007-004)**

EPA Undervoltage Trip Setpoint Calculation Uncertainty

Calculation JAF-CALC-ELEC-00757, "EPA for Normal Supply Feeder," Revision 6, dated December 20, 1995, assumed that there was no temperature effect (TE) on the uncertainty calculation if the device was operated anywhere within the specified operating temperature range of 40°F to 122°F. Regarding the basis of this assumption, the licensee stated that temperature effects would be captured in the referenced accuracy (RA) term of the uncertainty calculation. The inspector noted that the RA term, as stated in the calculation, was developed from statistical analysis of the Drift Analysis Instrument Report (JAF-RPT-RPS-00456). Data used in that analysis came from actual plant operation which did not cover the entire specified operating temperature. The licensee indicated the manufacturer did not separately account for TE for the installed EPA undervoltage components. Upon request, the licensee produced the sections of the vendor's equipment manual which described the existing (GEK83433C) and replacement (GEK 103900) EPA logic cards. The manual for the replacement EPAs, which the licensee indicated have not been installed, do indicate a TE over the required operating temperature range of $\leq$-0.6 Vac at 40°F to $\leq$+1.0 Vac at 127°F.

The inspector noted that Type 1 Change D1-90-228, which approved the installation of the replacement EPA logic cards on July 31, 1995, indicated that the replacement EPA logic card had increased thermal stability. The Type 1 Change also indicated that when the replacement logic card is installed, the setpoint calculations would be updated to reflect new temperature drift data.

c. Conclusions

Violations of the design control and test control requirements of 10 CFR 50, Appendix B, reflected a lack of rigor in the performance of design engineering activities.

E1.3 Mechanical Design Calculations

a. Inspection Scope (37550)

The inspector reviewed licensee responses to open items identified during a self-assessment Safety System Functional Inspection (SSFI) of the high pressure coolant injection system (HPCI). A design calculation was performed by the licensee in response to an open item pertaining to vortex formation in the condensate storage tank during HPCI pump suction switchover to the suppression pool. The inspector reviewed this calculation and others performed to support an alternate decay heat removal system (ADHR) modification.

b. Observations and Findings

The inspector reviewed several design calculations and identified several weaknesses as described below:

1. Calculation No. JAF-CALC-HPCI-00840, Revision 0, was performed in response to HPCI SSFI Open Item No. 22. The calculation concluded that the potential existed for vortex formation in the CST during HPCI pump suction switchover to the suppression pool in a postulated loss of coolant accident. The calculation qualitatively indicated that the short duration (less than 3 minutes) of these vortices and the potential for some air ingestion would not adversely affect HPCI pump operability. There was no indication that the pump manufacturer had been consulted to confirm that the pump would not be adversely affected by some amount of air ingestion.

   Subsequent to the inspection, the licensee informed the inspector that the pump manufacturer had agreed that the pump would not be adversely affected by the limited amount of air ingestion, and that the calculation will be revised to document the manufacturer's concurrence.

2. An analysis (Calculation JAF-CALC-DHR-03445 dated July 12, 1996) performed to evaluate the consequences of a moderate energy break in the DHR piping assumed failure of a non-safety-related sump pump as the limiting single failure. In addition, the calculation did not clearly indicate whether safety-related components might be adversely affected by the resulting calculated flood height. Non-safety-related components typically are assumed not to function as desired in evaluating the consequences of initiating events; consequently, the sump pump must be assumed not to function (versus a worst case single failure). In this case, failure of a safety-related component must be considered to ensure that worst case conditions are fully evaluated for the single active component failure. The licensee subsequently informed the inspector that the calculated 5.6-inch flood height

in the Crescent Area would not impact any safety-related equipment required for safe shutdown. The inspector agreed with the licensee's assessment, but observed that the calculation will need to be changed to consider the appropriate single failure vulnerabilities.

3. Calculation JAF-CALC-DHR-02380, "Alternate Decay Heat Removal System Thermal-Hydraulic Analysis," Revision 0, dated June 4, 1996, performed to verify a GE analysis of ADHR system performance used a computer model that had not been checked or documented. In addition, the computer code used in the calculation modeled the plate heat exchanges as counterflow tubular heat exchanges and did not confirm that results were consistent with the manufacturer's heat exchanger performance data sheet.

4. Calculation JAF-CALC-MISC-02244, "Assessment of the Combined Decay Heat Load of the Reactor Core and Spent Fuel Pool During Refueling Outages," Revision 0, dated January 29, 1996, was performed to support the installation of the new ADHR system as documented in JAF-RPT-DHR-02413, "Evaluation of the Decay Heat Removal System," Revision 3. This report provides the basis for the conclusions of safety evaluation JAF-SE-96-042, "Use of the Decay Heat Removal System in Various Plant Modes and Configurations," Revision 2. The calculation uses the methodology of Branch Technical Position ASB 9-2 to calculate decay heat. The report states in part, that the "... combined RPV and SFP decay heat loads have been conservatively calculated as a function of time post shutdown...." However, the calculation does not include the 10% uncertainty factor prescribed by the Branch Technical Position. Further, the report and the calculation incorrectly refer to this uncertainty factor (used in the BTP to account for differences in experimental data) as margin rather than as a correction needed to account for data spread as described in the BTP.

c. Conclusions

The licensee's evaluations of HPCI pump vortexing and moderate energy line break of DHR piping, and DHR heat exchanger modeling were additional examples of a violation **(VIO 50-333/96007-003)** of the design control requirements of 10 CFR 50, Appendix B, Criterion III.

The errors in the alternate decay heat removal system calculations reviewed by the inspectors had no adverse impact on safe operation of the system. However, the inspectors considered the items collectively to indicate lack of rigor in the performance of design activities.

E1.4 RHR Heat Exchanger Room HEPA Filter (Blower) Installation

a. Inspection Scope (37550)

A temporary high efficiency particulate air (HEPA) filter and blower were installed in the "A" RHR heat exchanger room in an attempt to reduce room temperatures that had resulted in high temperature alarms and emergency operating procedure (EOP) entries on several occasions during the summer. The inspector reviewed

Memorandum JTS-96-0369, dated August 20, 1996, which addressed questions (after the fact) as to whether this installation should have been considered a temporary modification. The inspector also discussed the installation with NYPA design engineers and the HVAC system engineer.

b. Observations and Findings

Memorandum JTS-96-0369 stated that: (1) Temperatures in the "A" RHR heat exchanger room (23RTD-01B) are about five Fahrenheit degrees warmer than in the "B" RHR heat exchanger room, and two degrees higher than those on which the entry conditions for emergency operating procedures were based; (2) The ultimate heat sink temperature limit has been raised from 77°F to 82°F (FSAR Section 9.7.1.2), providing a basis for raising the high room temperature alarm setpoint by five degrees; and (3) A setpoint change is being initiated to raise the high room temperature alarm setpoint.

As described in Section 4.10.3 of the FitzPatrick FSAR, an equipment area temperature monitoring system is utilized to detect reactor coolant pressure boundary leakage outside of the primary containment. Temperature sensors are located in the vicinity of the equipment to be monitored, and are calibrated with the station in operation with normal ventilation patterns and ambient temperature levels to detect a seven gallon per minute leak. The RHR equipment area temperature alarm is shown in Table 4.10-1 of the FSAR.

The inspector found that, prior to installing the temporary blower, the licensee did not document an evaluation to determine: (1) the impact of the existing higher normal operating temperatures on predicted maximum temperatures in the area during postulated accident, loss of offsite power, or safe shutdown conditions; (2) the effects of higher room temperatures on safety-related equipment required during accident or safe shutdown conditions; or (3) the effect of the HEPA filter/blower installation on the capability to detect steam leaks in the room, as described in the FSAR.

The licensee stated that all safety-related equipment in the room was reviewed, and is qualified to temperatures greater than 206°F. Thus, the slight increase in the setpoint temperature for EOP entry was (in retrospect) acceptable. The high energy line break analysis peak room temperature limit will not be affected by the higher room temperatures indicated by detector 23RTD-01B. This resistance temperature detector (RTD) is located near an un-insulated steam valve and is three feet above locations where more representative room temperatures prevail (~99°F). The licensee concluded that the HEPA filter/blower did not provide sufficient air flow to mask the detection of steam leaks. In addition, the licensee stated that the HEPA filter/blower installation had not been effective in reducing the bulk room temperature. Consequently, a setpoint change is being processed to resolve the problem.

10 CFR 50.59 permits licensees to make changes to the facility or to procedures, as described in the FSAR, without prior NRC approval, provided that the changes do not involve a change in the technical specifications or involve an unreviewed safety question. Records of these changes must include a written safety evaluation which

provides the bases for the determination that an unreviewed safety question does not exist. NYPA Administrative Procedure AP-05.02, "Control of Temporary Modifications," Revision 5, provides for a technical assessment of temporary plant modifications. The procedure defines a temporary modification as a "temporary alteration of plant equipment that does not conform to controlled plant drawings or other design documents." Further, Section 7.4 states (in part) that temporary modifications should be used "to correct a design deficiency when a permanent modification cannot be promptly installed..." The inspectors concluded that the HEPA filter/blower installation should have been controlled as a temporary plant modification, and that failure to perform and document a safety evaluation for the installation was a violation of 10 CFR 50.59. (**VIO 50-333/96007-005**)

The licensee agreed that the installation should have been treated as a temporary modification, and that the appropriate reviews should have been performed and documented. The licensee informed the inspector that the HEPA filter/blower had been removed, since it had not been effective.

c. Conclusions

The temporary filter/blower did not have an adverse impact on equipment area temperature monitoring system operation. However, the unevaluated installation of the temporary blower in the "A" RHR heat exchanger room was contrary to 10 CFR 50.59 requirement, for changes to the facility as described in the FSAR, and the licensee's administrative controls for temporary modifications. Licensee action to change the high room temperature alarm setpoints to preclude spurious high room temperature alarms and unnecessary EOP entries in hot summer months appeared to be appropriate.

E1.5 Design-Basis Documents

a. Inspection Scope

The inspectors reviewed the results of the licensee's design basis documentation (DBD) validation program which is managed by the licensee's corporate Engineering Programs group. Only two JAF DBDs have been validated to date; residual heat removal (RHR) DBD-10 (December 2, 1994) and air treatment system DBD-27 (December 27, 1994).

b. Observations and Findings

The inspectors observed that the licensee's DBD validation project to date had identified 114 discrepancies within the RHR DBD. Fifty-four of the items were forwarded to the FitzPatrick site for resolution in memorandum CM-BDDM-95-04, dated April 26, 1995. The discrepancies involved questions concerning the Final Safety Analysis Report (FSAR), procedures, lesson plans, and design-basis calculations. The inspectors found that site engineering had not acknowledged or taken any action on the 54 DBD items prior to the inspection. The licensee subsequently found that a similar problem also existed regarding the safety-related air treatment system (ATS) DBD open items forwarded to the site.

On October 11, 1996, the licensee issued DERs 96-1214 and 96-1215 to review and evaluate the RHR and ATS open items. Twenty-four of the 54 RHR items were immediately dispositioned based on prior work, and the remaining 30 items were reviewed by the licensee for operability and assigned Action Commitment Tracking System (ACTS) item numbers for followup. All of the ATS items were assigned ACTS item numbers for followup.

c. Conclusions

The licensee's failure to promptly identify and disposition the DBD open items was the first of two examples of a violation of the corrective action requirements of 10 CFR 50, Appendix B, Criterion XVI. **(VIO 50-333/96007-006)**

E1.6 Closure of ACTS Items Related to Safety System Functional Inspections

a. Inspection Scope (37550)

The inspector reviewed the basis for closure of several Action/Commitment Tracking System (ACTS) items that had been closed by NYPA. The inspector found two instances in which ACTS items identified during SSFIs were not fully addressed by the licensee.

b. Observations and Findings

Surveillance Testing of RHR Heat Exchanger Service Water Flow

Surveillance procedure ST-2X, "RHR Service Water Flow Rate, Strainer, and Inservice Test (IST)," verifies that the residual heat removal service water (RHRSW) pumps individually will deliver the technical specification-required flow rate of 4000 gpm to the RHR heat exchanges. RHR SSFI Observation ME-06 identified that instrument error was not accounted for in the acceptance criteria of ST-2X. A similar issue was identified by the NRC during an emergency service water SSFI in 1992 (IR 50-333/92-081). Actions were completed to address instrument error on a programmatic basis in revisions to Procedure AP-19.01, "Surveillance Testing Program." ACTS #13038 closed the open item on this specific issue (ST-2X) based on the licensee's judgement that there is considerable margin in the heat transfer capability of the RHR heat exchanges, assuming flows less than those required by the JAF Technical Specifications.

ACTS #13925 requested that the instrument error associated with measuring RHRSW flow using the installed instrumentation and ultrasonic flow meters should be established. However, this item was still open at the time of the inspection and was not scheduled for completion until November 22, 1996. Recent ST-2X surveillance test results indicate that, on several occasions, measured RHRSW flow to the RHR heat exchanges was 4000 gpm. However, actual flow rate could have been less than 4000 gpm when instrument error is considered. The inspector concluded that the acceptance criterion did not adequately verify the minimum flow rate established in the technical specifications. This is the second example of a violation of the test control requirements of 10 CFR 50, Appendix B.

For the following reasons, the inspector also concluded that the RHRSW pumps were functional: (1) Procedure ST-2X establishes RHRSW flow as closely as possible to the inservice test reference value of 4000 gpm by throttling closed the RHR heat exchanger outlet throttle valves. Under accident conditions, the throttle valves would open fully providing additional flow through the heat exchanges; (2) Test TST-22, performed to verify the pump performance curves, shows that the pumps are capable of delivering flow rates in excess of 5000 gpm; (3) Comparison between the normally installed instruments and temporary ultrasonic flow instruments, indicate that the installed instruments underestimate pump flow by as much as 400 gpm.

ESW Cross-Connect Valve Leakage

ACTS #4242 originated from an NRC observation during the emergency service water (ESW) SSFI, and concerned leakage across valve 15MOV-101 that might adversely impact flow supplied to ESW loads. The ACTS item was closed based on Memorandum JTS-93-0800 dated December 3, 1993, "Leakage Across 15MOV-101, RBCLC/ESW Cross-Connect Supply Valve." The memorandum states that the redundant ESW pump would compensate for any cross-connect leakage. However, assuming a single failure of the redundant pump during an accident, leakage could impact flow supplied to other ESW loads. The licensee did not address this issue, and the inspectors considered the licensee's basis for closure to be incomplete.

Subsequent to the inspection, JAF Engineering developed a revised evaluation (JTS-96-0472, "Potential 15MOV-101 Seat Leakage," dated November 2, 1996) and basis for closure of this ACTS item. The revised evaluation stated that local leak rate test data for similar type valves indicate leakages of less than one gpm. In addition, the evaluation established that the potential for seat surface degradation of this valve is minimized by operational history, the results of inspections, and more favorable system and operating conditions.

c. Conclusions

Based on the revised evaluation of ESW valve 15MOV-101, the inspector considered it unlikely that seat leakage would adversely impact flow to other ESW loads under accident conditions. However, the inspector also concluded that the licensee's initial bases for ACTS item closure were not always complete and thorough.

The RHRSW flow acceptance criterion of surveillance procedure ST-2X did not account for instrument error, and thus did not incorporate acceptance limits contained in applicable licensing documents. This is an additional example of a violation **(VIO 50-333/96007-004)** of 10 CFR 50, Appendix B, Criterion XI, "Test Control."

E1.7 Modifications

a. Inspection Scope (37550)

The inspector reviewed several minor modifications and temporary modifications including:

- MMP No. M1-92-088, "Replace 02-2SOV-001 and 002 with Piston Check Valves," Revision 0, dated April 17, 1996
- MMP No. M1-95-103, "Replacement of Reactor Sample Containment Isolation Valves 02-2AOV-39,40," Revision 0, dated April 29, 1996
- Type 1 Change # D1-96-007, "Replacement of MSSRV 3-Way Solenoid Valves," Revision 1
- Temporary Modification 95-127, Ultrasonic FW Flow Equipment
- Temporary Modification 96-123, Recorder to monitor RWR A&B Seal Parameters
- Temporary Modification 95-093, Temporary Sample Point for Reactor Coolant Samples

In addition, the inspector reviewed temporary modification audits and sampled associated surveillance test results.

b. Observations and Findings

Two non-safety-related temporary modifications have been in place since 1991. The licensee stated that the modifications (91-224 and 91-238) were scheduled to be made permanent in 1997. The remainder of the installed temporary modifications were initiated in the 1995-96 time frame. The inspector reviewed several of these temporary modifications and identified no problems. In addition, the inspector sampled several temporary modification audits (e.g., ST-1Q, "Protective Tags and Temporary Modification Verification," Revision 4) and found that temporary modifications were being appropriately reviewed by the licensee to ensure that they are properly authorized, installed, and evaluated.

c. Conclusions

The inspector concluded that minor and temporary modifications were appropriately documented, and implemented in accordance with plant procedures.

E2 Engineering Support of Facilities and Equipment

E2.1 Setpoint Control

a. Inspection Scope

The inspectors reviewed the methodology used by the licensee to extend the calibration period for technical specification-related instrument loops to support a 24-month operating cycle. The methodology was documented in report JAF-RPT-RPS-0132A, "Reactor Protection System (RPS) Surveillance Test Extensions," Revision 3, dated November 1995.

b. Observations and Findings

The inspectors noted that the RPS report methodology indicated that if surveillance records revealed more than one failure to meet acceptance criteria per component, then the surveillance frequency could not be extended. The inspectors found the setpoint change request for the average power range monitor (APRM) flow bias trip had been issued to maintenance on September 20, 1996, to change the calibration period to 30 months.

The inspectors reviewed an instrument drift analysis that showed that the APRM flow transmitters were found out of calibration 50% of the time between 1986 and 1992. During that time, the flow instruments were manufactured by either Barton or Foxboro. All eight flow transmitters were changed to a Rosemont design in 1993 by Modification #F1-87-099 to address the calibration problem without changing the calibration period. The January 12, 1995, calibration of the Rosemont transmitters resulted in transmitters A and B being found out of tolerance in the non-conservative direction (DER-95-0290). The latest transmitter calibrations on September 16, 1996 and October 17, 1996, resulted in three of eight transmitters being found out of calibration.

The inspectors noted that Technical Specification (TS) Basis 4.1 justified a refueling outage calibration period for the APRM flow bias trip function, based on no significant drift at other plants. Amendment 233 to the TS recently changed this justification based on a plant-specific drift evaluation. The inspectors found no justification for the latest TS Basis statement, particularly in light of instrument calibration failures documented in 1995 and 1996. In response to the inspectors' finding (and similar questions raised by the JAF maintenance I&C department during this inspection), the licensee issued memorandum JIC-96-120, dated October 10, 1996, to decrease the calibration period to 12 months.

c. Conclusions

The licensee failed to identify and correct promptly a condition adverse to quality involving an unjustified extension of the APRM flow bias trip calibration period. This is the second example of a violation **(VIO 50-333/96007-006)** of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

E4 Engineering Staff Knowledge and Performance

E4.1 Surveillance Test Acceptance Criteria

a. Inspection Scope

The inspectors reviewed the history of battery surveillance servic st MST-71.20 to assess the progression of the acceptance criteria. The inspectors also reviewed the station battery modified performance test acceptance criteria contained in procedures MST-071.24, Revision 2, dated December 27, 1994, (battery A) and MST-071.26, Revision 0, dated January 10, 1995, (battery B), and compared the criteria against direct current (dc) voltage drop calculations JAF-CALC-ELEC-00426 (battery A) and JAF-CALC-ELEC-00427 (battery B).

b. Observations and Findings

The original acceptance criterion of battery service test MST-071.20 was 1.5 volts per cell. Subsequently, the criterion was changed to 1.0 volt per cell. Until Revision 2 of the procedure was approved in August 1989, no battery terminal voltage criterion was included. At that time, 101.5 volts was established as the test cutoff voltage. In June 1991, the test cutoff voltage was raised to 105 volts in Revision 4 of the procedure. The acceptance criterion remained 105 volts with the new modified performance tests MST.071.24 and MST.071.26.

The inspectors found the 105 volt direct current (dc) acceptance criterion in the battery service test portion of modified performance tests, MST-071.24 and MST-071.26, had no basis in design. The criterion did not relate to the minimum-required battery terminal voltage of 109 volts dc used in the voltage drop analyses. The licensee issued DER 96-11 in response to the finding and performed an operability determination that compared the results of the latest battery service tests to determine voltage at the safety-related loads. The licensee then provided justifications for those components that could experience voltage less than nominal rating.

The inspectors noted that the licensee's analysis assumed the minimum design battery temperature, which would provide additional margin. Following the inspection, the licensee informed the inspector that it would reinstall two previously removed cells to the station batteries (for a total of 60 cells), to provide additional margin, until a complete reanalysis of the dc system can be performed.

c. Conclusions

The licensee's engineering and maintenance staffs did not recognize that the purpose of a service test was to demonstrate that the battery could supply sufficient voltage to the design-basis electrical loads. The inspectors concluded that the station batteries were functional, but that the acceptance criteria for the battery test procedures had no bases in design. This is the third example of a violation **(50-333/96007-004)** of the test control requirements of 10 CFR 50, Appendix B, Criterion XI.

E7 Quality Assurance in Engineering Activities

E7.1 Engineering Assurance

a. Inspection Scope

The inspectors reviewed the results of the latest engineering assurance (EA) of phase I of the modification quality assessment documented in NYPA Memorandum KM-96-016, dated August 21, 1996. The EA team was composed of individuals from the licensee's White Plain Office and the Indian Point-3 site engineering staff. The EA team reviewed 28 representative modifications developed after 1992. The licensee indicated that the scope of the EA review was limited to the engineering package, up to the point of issue to the field for installation. The EA reviewers utilized a checklist that covered areas such as design interfaces, test requirements, specifications, design reviews, calculations, design verification, and modification file documentation. In addition, the EA also considered the document control concern documented in NRC unresolved item (URI) 50-333/95-13-01. Ninety-two (92) deficiencies were identified by the licensee.

b. Observations and Findings

The inspectors reviewed one of the twenty-eight checklists used by the EA team, and had the following observations:

- Modification F1-89-158, "Power 27 MAP from Station Batteries," added inverter and control circuit loads to each station battery. The modification file documentation section of the checklist included a subsection for a "documents to be revised list." This subsection did not identify specific plant documents that were reviewed for required revisions. Although the checklist indicated everything was satisfactory, a check of the modification package in response to the inspector's question revealed that the related battery surveillance procedure was not included even though loads were being added to the battery. Both the modification process and the EA review missed this document.

- The inspectors noted that the licensee's design verification review identified that calculation JAF-CALC-ELEC-1387, which had been performed by an outside consultant, had not received a NYPA technical review as required by the DCM-11 design control process. The EA reviewer failed to recognize that this was a similar concern to that documented by the NRC in Unresolved Item 50-333/95-13-01 concerning document control.

- The inspectors observed that the EA modification review checklist identified an electrical change control form (ECCF) that had been issued late. The inspector found that the review failed to note that the load addition described in the modification had been incorrectly incorporated into the calculation with a different (non-conservative) value (see Section E1.1).

c. Conclusions

The inspectors concluded that the licensee's engineering assurance program was a good initiative. However, the discrepancies identified by the inspector in the single sample chosen potentially indicated weakness in the depth of review. This is an inspector followup item pending review of phase II of the EA assessment of modification quality. **(IFI 50-333/96007-07)**

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 50-333/96-05-04

a. Inspection Scope (37550)

The inspector reviewed the licensee's corrective actions in response to unresolved item 50-333/96-05-04. A previous inspection identified errors and weaknesses in a calculation performed to justify up to a 12-inch diameter opening in the secondary containment without impacting the 1/4-inch water column (WC) negative pressure requirement for the standby gas treatment (SBGT) system. The inspector reviewed:

- Corrective actions outlined in DER 96-0867.
- Calculation JAF-CALC-SC-01876, Revision 1, that addressed identified weaknesses.
- Calculation JAF-CALC-SC-02514, "Acceptance Criteria for ST-39D, Reactor Building Leak Rate Test," Revision 0.
- ST-39D, "Reactor Building Leak Rate Test," Revision 13.

b. Observations and Findings

Calculation JAF-CALC-SC-01876 was revised (1) to correct the erroneous resistance coefficient used for the piping penetration, (2) to incorporate the latest reactor building leak rate test results, and (3) to envelope possible air temperatures. The results of the revised analysis indicated that the SBGT system is capable of maintaining the required negative differential pressure with a 12-inch diameter hole in secondary containment. The inspector reviewed the revised calculation and found that the coefficients and enveloping temperatures assumed were appropriate.

The inspector also reviewed calculation JAF-CALC-SC-02514, which established acceptance criteria to ensure acceptable leak rates. No problems were identified with this calculation. In addition, procedure ST-39D now requires engineering review and concurrence that the acceptance criteria are satisfied.

c. Conclusions

The inspectors concluded that the corrective actions outlined in DER 96-0867 appropriately address the issues raised. Further, the revised calculation provides appropriate corrections to the methodology used, and the reactor building leak rate

test acceptance criteria is consistent with the results of that analysis to ensure that design basis reactor building (negative) differential pressures are maintained.

E8.2 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description.

While performing the inspections discussed in this report, the inspectors reviewed the portions of the Fitzpatrick FSAR that related to inspected areas, e.g., FSAR Sections 4.10, 6.4 and 6.5, High Pressure Coolant Injection. An inconsistencies was noted between the wording of Section 4.10 of the FSAR and installation of a temporary blower in the "A" RHR heat exchanger room (Section E1.3).

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

a. Inspection Scope (83750)

The inspector reviewed the licensee's program and controls for assuring radiological worker safety during a refueling outage. Areas examined included: work controls; radiation work permits; pre-job preparations and briefings, including reviews to maintain occupational exposures as low as is reasonably achievable (ALARA); radiological worker practices; and radiation protection technician work practices. The inspector also attended shift turnovers conducted between supervisors, chief technicians and journeyman technicians.

b. Observations and Findings

During the last licensee refueling outage (RFO11), the NRC identified extensive problems with radiological worker and radiation protection technician work practices and documented the results in NRC Inspection Reports 50-333/94-30, 95-03, 95-10. Since RFO11, the licensee has undertaken an effort to address these issues, and to significantly upgrade worker performance, especially during outages.

In support of the current refueling outage, the licensee's Radiological and Environmental Services (RES) Department had modified its staffing and work practices to include the addition of approximately 60 contractor health physics and decontamination technicians, as well as upgrading several technicians to acting chief technicians for certain critical work areas. A supervisor and one or more chief technicians were assigned to the refuel floor, drywell and balance of plant (including turbine building and reactor building), for each of two twelve-hour shifts. These were conducted in a professional manner, outlining all work activities in progress and stressing current and potential changing radiological conditions.

In order to improve the control of work in the radiologically controlled area (RCA), the licensee established two satellite control areas and an additional satellite control/access control point, in addition to the main and secondary access control points located in the new and old administration buildings, respectively. The two satellite control points were established on the Reactor Building 272' elevation, outside the drywell personnel access point and on the refueling floor. Each included a temporary office structure where workers could check-in with the radiation protection staff, receive pre-job briefings and log onto specific radiation work permits (RWPs). The additional satellite control/access control point was established on the turbine deck just outside of the high pressure turbine. The inspector observed numerous pre-job briefings at all three of these control points. These were conducted in a professional manner by the radiation protection technicians, providing extensive information on radiological conditions in the work areas. The inspector also noted a significant improvement in worker attitude by the radiation protection technicians, especially at the main access control point. During RFO11, the inspector had observed technicians having a non-responsive attitude towards assisting radiation workers. This outage, radiation technicians were observed on numerous occasions assisting workers with logging-in on the access control computers, responding to portal monitor alarms and aiding workers in exiting contaminated areas throughout the plant. During high traffic times at the main access control point, radiation technicians not assigned to access control duties were observed leaving their desks and lunchroom to assist radiation workers.

For the outage, the RES Manager had assigned one senior radiation protection technician to oversee all three of the access control points (one per shift). Their duties included: assisting workers with the computerized log-in system; ensuring workers dosimetry was properly worn (an issue previously identified in NRC Inspection Report 50-333/94-30); assisting workers exiting the RCA through the portal monitors; responding to portal monitor alarms; and tracking and investigating personnel contaminations.

The inspector reviewed the contamination log maintained by the licensee, and concluded that with two exceptions, many of the contaminations were unrelated and not common to any one causal factors, such as poor work practices, improper dress-out or failure to control the spread of contamination.

Two clusters of personnel contaminations were noted in the logs, however. The first involved three contaminations which occurred on the refuel floor during reactor disassembly, the other during initial work on the D-MSIV in the drywell. In the former, the licensee concluded that the contaminations were the result of poor radiation worker practices and responded by issuing a deviation event report (DER) and holding a stand-down meeting with the refuel floor contractor whose workers were contaminated. Since the stand-down meeting, no additional personnel contaminations were identified involving refueling floor workers. In the latter case, two workers, one each on the day and night shift, became contaminated by free-standing water inside the MSIV valve body. Subsequent to this, the licensee initiated a remedial training program for each shift's work crew utilizing a mock-up of the MSIV.

For RFO12 the licensee had established an outage exposure goal of 168.8 person rem. This was based only partially on the scope of work to be performed. The goal was principally established in order for the facility to meet a long-term goal of being in the top quartile of all boiling water reactors in the United States for three-year average personnel exposure. Prior to the outage, the license's ALARA staff estimated that 180 person-rem was the more likely exposure based on work to be performed during the outage. Through day 13 of the outage, exposures were approximately 26 person-rem ahead of projection. Part of the cause for this was a earlier start to some high exposure work in the drywell, higher than predicted exposures during reactor disassembly, and an expansion of work scope for snubber inspections due to test failures. Discussion with licensee representatives indicated that outage exposure was now likely to be approximately 200 person-rem.

On October 30, 1996, a contractor work crew entered the drywell, a posted locked high radiation area, and worked there for approximately three hours. One of the three workers in this crew failed to properly log-in at the drywell satellite access control point, which meant that his alarming dosimeter was not turned on during his drywell entry. Plant Technical Specification 6.11 requires that for each locked high radiation area, workers utilize a radiation work permit and have an alarming dosimeter with them. The RWP for this job (RWP #96-0411) clearly indicated the need to wear an alarming dosimeter. The worker did not identify his failure to have his dosimeter turned on until after he had left the drywell and was preparing to exit the reactor building. Licensee investigation concluded that the worker had not properly logged in on the access computer at the satellite control point, and that the worker, who admitted confusion with the access system, failed to ask for assistance (even though there were three radiation protection technicians present at the satellite access control point), and failed to check his dosimeter prior to entry to the drywell. Based on the exposures received by the other two members of this work crew, the worker in question was assigned an exposure of 64 millirem for this entry. The licensee also informed the inspector that there were additional cases where individuals had failed to wear dosimetry as required. The failure to follow plant technical specifications for locked high radiation area entry is a violation **(50-333/96007-08)**. While this violation would normally be a candidate for enforcement discretion, the NRC elected to issue a violation in this matter due to the length in which the violation existed and the number of possible opportunities available to identify the problem.

c. Conclusions

Significant improvements were noted in radiological worker and radiation protection technician performance. Significant attention has been focused on radiological worker performance, and several licensee initiatives in this area were observed. One violation concerning proper high radiation area entry was identified.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope (83750)

The inspector reviewed QA audits and surveillances in order to evaluate the effectiveness of quality assurance activities in the RES Department. In addition to a

plant audit completed in October, 1996, the inspector also discussed surveillance activities on-going during the refueling outage.

b. Observations and Findings

As part of its review of work activities and the effectiveness of corrective actions for identified deficiencies during the last refueling outage (RFO11), the licensee had a lead auditor, a corporate auditor and a six-member team of personnel conducting independent observations of radiological worker and radiation protection technician practices during RFO12. The inspector observed several of these surveillances and discussed current findings with all three reviews. The reviewers reported no significant findings, and considered the radiation protection technicians to be much more responsive to radiological worker needs than had been observed in the past.

The inspector also reviewed a recently issued audit report, A96-17J, "Radiation Protection Program," dated October 31, 1996. This report was conducted by a team of auditors and outside technical specialists during late September and early October of 1996. The audit focus was on implementation of changes to radioactive material shipping regulations contained in Title 49, Code of Federal Regulations, and radiological worker and radiation protection technician practices in preparation for RFO12. Two DERs were issued as a result of this report.

The inspector noted that one of the DERs issued from audit A96-17J involved a licensee procedural requirement for training of radiation protection technicians involved in the shipping program. The procedural requirement, found in paragraph 6.3.1 of licensee procedure RW-SHP-104, Rev 1, "Radioactive Waste Data Base Control Program," requires that these technicians be trained and certified for the operation of the RADMAN (WMG, Inc.) computer code. The auditors noted that the certification for use of this code had lapsed as of June 1996. The DER (#96-1188) was issued on October 10, 1996. On October 22, 1996, the licensee shipped radioactive wastes in an NRC-approved LSA > Type A shipping cask (Certificate of Compliance USA/9094/A) utilizing the RADMAN computer code without having the technicians certified or the procedure revised relative to the certification requirement. The licensee's RES supervision had previously determined that the corrective action for the DER was to delete the certification requirement, but did not ensure the procedure was revised prior to subsequent shipments. The inspector noted that no other corrective measure was apparent relative to assuring that the technicians were adequately qualified relative to the application of the RADMAN code.

Title 10, Code of Federal Regulations, Part 71 requires that licensee's utilizing NRC licensed shipping containers, such as that utilized here, follow a formal quality assurance program for their use, including the identification and correction of deficiencies and deviations. The failure to correct discrepancies identified with the certification of technicians responsible for radioactive waste shipping is a violation **(50-333/96007-09)**.

c. Conclusions

The licensee's program for assurance of quality in the radiation protection program, especially its audit and surveillance program, is generally very effective. One violation regarding corrective action effectiveness in the radioactive shipping program was identified.

P8 Miscellaneous EP Issue

During the week of September 30, 1996, a region-based inspector conducted a telephone interview with the licensee to complete NRC Temporary Instruction (TI) 2515/134, "Licensee On-Shift Dose Assessment Capabilities". The purpose of the TI was to gather information on the licensee's capabilities to perform on-shift dose assessment. It was determined that the licensee does have on-shift dose assessment capability supported by appropriate procedural guidance and therefore meets NRC requirements to be able to perform dose assessment at all times.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspections results to members of the licensee management at the conclusion of the inspection on November 26, 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.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Colomb, Plant Manager
R. Locy, Operations Manager
D. Ruddy, Director, Design Engineering
J. Maurer, General Manager, Support Services

NRC

C. Cowgill, Chief, Projects Branch 2

INSPECTION PROCEDURES USED

37550	Engineering
37551	Onsite Engineering
62703	Maintenance Observations
61726	Surveillance Observations
71707	Plant Operations
71750	Plant Support
73753	Inservice Inspection
83750	Occupational Radiation Exposure

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

50-333/96007-01	VIO	A personnel error contributed to the incorrect exchange of three CRDs. The failure to accurately locate CRDs for exchange is a violation.
50-333/96007-02	IFI	Affect of RWCU and CRD flow on natural circulation flow characteristics of the reactor vessel, refueling cavity and SFP regions during ADHR testing.
50-333/96007-03	VIO	10 CFR 50, Appendix B, Criterion III, Design Control; failure to translate design into procedures and to verify the adequacy of design. (Five examples)
50-333/96007-04	VIO	10 CFR 50, Appendix B, Criterion XI, Test Control; failure to incorporate appropriate acceptance limits into procedures. (Three examples)
50-333/96007-05	VIO	Failure to perform a 10 CFR 50.59 safety evaluation for installation of a temporary blower/filter in the "A" RHR heat exchanger room
50-333/96007-06	VIO	10 CFR 50, Appendix B, Criterion XVI, Corrective Action; failure to identify and correct promptly conditions adverse to quality involving design basis documentation verification program deficiency items and miscalibration of APRM flow bias flow transmitters

50-333/96007-07	IFI	Review Engineering Assurance Program phase II assessment of modification quality
50-333/96007-08	VIO	Failure to follow plant technical specifications for locked high radiation area entry.
50-333/96007-09	VIO	Licensee failed to follow a formal quality assurance program for the use of NRC licensed shipping containers.

Closed

50-333/96005-04	URI	Secondary containment calculation deficiencies

Discussed

None