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REGION II

Docket Nos.: 50-250 and 50-251
License Nos.: DPR-31 and DPR-41

Report Nos.: 50-250/96-02 and 50-251/96-02

Licensee: Florida Power and Light Company
Facility: Turkey Point Units 3 and 4
Location: 9250 West Flagler Street
Miami, FL 33102

Dates: February 11 through March 23, 1996

Inspectors: P.S. Mellen 4/22/96
for T. P. Johnson, Senior Resident Inspector — Date Signed

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Reactor Projects Branch 3
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EXECUTIVE SUMMARY
TURKEY POINT UNITS 3 AND 4
Nuclear Regulatory Commission Inspection Report 50-250,251/96-02

This integrated inspection was conducted by the resident, regional, and headquarters inspectors to assure public health and safety, and it involved direct inspection at the site in the following areas: plant operations including the refueling outage, operational safety, and plant events; maintenance including surveillance observations; engineering; and plant support including radiological controls, chemistry, fire protection, and housekeeping. Backshift inspections were performed in accordance with Nuclear Regulatory Commission inspection guidance.

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations. The inspectors identified two non-cited violations, three unresolved items, and one inspector followup item:

96-02-01	NCV, Failure to Meet Auxiliary Feedwater Surveillance Requirements (section M6.2.)
96-02-02	IFI, Auxiliary Feedwater Issues (section E2.1)
96-02-03	URI, Failure to Update the Final Safety Analysis Report (section E8.2)
96-02-04	URI, Radwaste Building Spill (section R1.1)
96-02-05	URI, Spent Fuel Pool Transfer Canal High Radiation (section R1.4)
96-02-06	NCV, Failure to Survey Material Leaving the Radiation Controlled Area (section R4.1)

During this inspection period, the inspectors had comments in the following functional areas:

Plant Operations

- The licensee's corrective actions and investigation for canal grass influx events were thorough and very professional. Both a voluntary Unit 3 shutdown and a Licensee Event Report were also noted (section O1.1).

- Operator performance during the Unit 4 refueling outage shutdown, cooldown, and draindown activities was very good. Further, the licensee continues to offload the core, and not to enter reactor coolant system reduced inventory or midloop operations (section O1.2).

- Core alteration procedures were appropriately implemented. However, improvements were required relative to spent fuel bridge operations and control room oversight (section O1.3).

- The licensee appropriately identified, addressed, and reported an issue regarding Unit 3 control rod position indication (section O2.1).

- The installation of drain rigs on the operable 4B safety injection pump without management or engineering concurrence was a weakness (section O2.2).

- A Unit 3 automatic reactor trip was caused by a less than optimal operator response to steam generator level transients, weaknesses in control room command and control, and control room oversight and, a balance of plant equipment failure. Licensee response to this event, including line management and quality assurance reviews, was thorough and self-critical (section O4.1).

- Effective operator training was noted relative to Unit 4 outage related modifications, NRC Bulletin 96-1(generic control rod insertion failures), and decay heat removal (sections O5.1 and O5.2).

- The Unit 4 refueling outage was conducted with a noted strong safety-conscious oversight by both line management and the quality assurance organization. The licensee conservatively maintained equipment available to remove decay heat. (section O7.1).

- An operator error resulted in an overflow of a radwaste tank and a minor spill. This issue was unresolved (section R1.1).

Maintenance

- Outages on both the Unit 3 and Unit 4 spent fuel pool cooling systems were satisfactorily conducted; however, weaknesses were noted on freeze seal procedural guidance and work order documentation (section M1.1).

- Unit 4 emergency diesel generator overhauls and testing were appropriately performed, and the licensee adequately addressed personnel performance and equipment issues (section M1.2).

- The motor operated valve coordinator was knowledgeable and maintained cognizance and ownership of related activities on Unit 4 (section M1.3).

- Unit 4 power-operated relief and block valve maintenance was appropriate (section M1.4).

- As-found Integrated Local Leak Rate related issues were appropriately documented in condition reports (section M1.5).

- The licensee's flow-accelerated corrosion program was noted to be detailed, proactive, and well administered (section M1.6).

- Unit 4 turbine-generator overhaul and modification work were noted to have excellent oversight, and work performance was well controlled (section M1.7).

- Unit 4 steam generator inspection and cleaning activities were well coordinated and implemented. Further, a foreign material issue was appropriately addressed (section M1.8).

- Unit 4 reactor pressure vessel disassembly evolutions were well planned and executed. Overall performance was noteworthy (section M1.9).

- Unit 4 component cooling water pressure switch maintenance was well planned and implemented (section M1.10).

- Review of Unit 4 main steam flow trap modifications revealed good weld and film quality (section M1.11).

- Unit 4 component cooling heat exchanger testing was well performed, with conscientious procedure compliance (section M2.1).

- The licensee's primary and secondary leak reduction program was effective (section M2.1).

- Although the steam generator feedpump check valves were not safety-related, weaknesses were identified relative to corrective actions and generic implications of a 1993 failure. Furthermore, Quality Assurances's review of this issue was thorough and incisive (section M2.2).

- The licensee prudently shutdown Unit 3 to address a rod control issue, and maintenance/engineering troubleshooting activities were well controlled and demonstrated strong teamwork (section M2.3).

- Licensee was responsive to inspector comments about the need to heighten operator awareness of the potential consequences of the 3C charging pump discharge valve failure (section M2.4).

- Two crane related issues that occurred during the Unit 4 outage illustrated a need for enhancements, attention to detail, and training; however, safety significance was minor (section M2.5).

- The licensee's effort to refurbish the Unit 4 steam generator level control system was thorough and well implemented (section M2.6).

- The licensee appropriately addressed the generic and safety aspects of an air-operated valve failure associated with the

intake cooling system supply to the turbine plant cooling water (section M2.7).

- Weaknesses, both in the scaffold control program and in the control of contract painters, resulted in perturbations on both units (section M6.1).

- A licensee identified missed surveillance on auxiliary feedwater initiation was a non-cited violation (section M6.2).

Engineering

- The end-of-cycle Unit 4 power and temperature coastdown was well planned and executed (section E1.1).

- A small leak on the 4A residual heat removal system heat exchanger was appropriately identified, dispositioned, and repaired (section E1.2).

- Recent issues associated with the auxiliary feedwater system was an inspector followup item (section E2.1).

- Unit 4 modifications associated with the core reload, boron injection tank, emergency load sequencer, main steam safety valve discharge piping, intake cooling water and structure, control rod timing order, containment hatch security keys, control rod drive spare mechanism canopy seal clamps, and the black start diesel electrical tie elimination were appropriately performed and documented (sections E2.2 through E2.11).

- The monthly operating reports and four licensee event reports were appropriately written and submitted (section E3.1 and E3.2).

- The practice of full core offloads into the spent fuel pool was not analyzed for Turkey Point (section E8.1).

- Failure to periodically update the Final Safety Analysis Report for multiple examples (spent fuel pool full core offloads, transient population update, and use of temporary cavity filtration systems and temporary radwaste systems) was an Unresolved Item (section E8.2).

Plant Support

- Periodic Unit 4 containment inspections noted appropriate housekeeping controls and acceptable material condition (section R1.2).

- Radiological controls noted during the Unit 4 outage demonstrated very good practices including the use of cameras, closed circuit television viewing, and dose telemetry (section R1.3).

- Noted high radiation levels in the vicinity of the Unit 4 spent fuel pool transfer canal (e.g., on the auxiliary building roof) during fuel transfer activities was unresolved (section R1.4).

- The employee termination process did not assure that all individuals received speakout interviews or whole body counts; however, licensee procedures appropriately addressed this possibility (section R3.1).

- Failure to adequately survey a nitrogen bottle which was transported outside the radiation controlled area was a licensee identified, non-cited violation (section R4.1).

- Local area brush and grass fires did not affect the emergency plan evacuation routes (section P1.1).

- The vehicle barrier system was implemented and security personnel were knowledgeable (section S2.1).

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Summary of Plant Status

Unit 3

At the beginning of this reporting period, Unit 3 was shutdown due a reactor trip that occurred February 9, 1996 (section O4.1). The unit restarted on February 11, and was online February 12, 1996. The unit was reduced to 60% on February 16, and was subsequently shutdown due to grass/algae problems. The unit restarted on February 19, 1996; however it was shutdown due to rod control problems. The unit restarted and achieved full power on February 21, 1996. The unit remained at full power for the remainder of the period.

Unit 4

At the beginning of this reporting period, Unit 4 was operating at or near full reactor power and had been on line since March 12, 1995. The unit entered end-of-cycle coastdown on February 25, 1996. The unit was shutdown for its cycle 16 refueling outage on March 4, 1996. The unit remained in the outage for the remainder of the period.

I. Operations

Inspection Scope (40500, 60710, 71707, and 93702)

The inspectors verified that the licensee operated the facilities safely and in conformance with regulatory requirements. The inspectors accomplished this by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and technical specification compliance, review of facility records, inspections of outage preparations and activities, and evaluation of the licensee's management control.

The inspectors reviewed plant events to determine facility status and the need for further followup action. The significance of these events was evaluated along with the performance of the appropriate safety systems and the actions taken by the licensee. The inspectors verified that required notifications were made to the NRC and that licensee followup including event chronology, root cause determination, and corrective actions were appropriate.

The inspectors also performed a review of the licensee's self-assessment capability by including PNSC activities, QA/QC audits and reviews, line management self-assessments, individual self-checking techniques, and performance indicators.

Inspection Findings

O1 Conduct of Operations

O1.1 Unit 3 Canal Grass and Algae Influx Events

On February 15 and 16, 1996, canal grass and algae influx events occurred on Unit 3, fouling the intake structure. The Turkey Point intake structure includes eight individual bays (four per unit). Each bay has an outer "grizzly" screen, an inner traveling screen with screen wash capability, and an intake well for cooling pump suctions. Each well is shared by a circulating water pump and either an ICW pump (three per unit) or screen wash pumps (three shared pumps). These events were similar to events that occurred on March 9, 1995 (reference NRC Inspection Reports 50-250,251/95-6 and 9) and again on January 31, 1996, (reference NRC Inspection Report 50-250,251/96-01).

The licensee entered procedure 3-ONOP-11, Screen Wash Malfunction. As a precaution, Unit 3 was reduced from full power to 60%. Unit 4 remained at full power, and was not affected. Maintenance personnel assisted operations in cleaning screen and ICW strainers (TPCW and CCW). Personnel were stationed continually at these locations. During ICW to CCW strainer cleanings on February 16, 1996 at 2:00 a.m. and 3:00 a.m., the flows (for the ICW to the CCW heat exchangers) were reduced to values less than the required administrative limits per procedure 3-OP-019, Intake Cooling Water System. In each case, the licensee entered Technical Specification 3.0.3 and made a 10 CFR 50.72 event notification to the NRC. At 4:32 p.m., on February 28, 1996, the licensee subsequently retracted both event notifications based on analyses which concluded that the flows were within allowable limits. The inspector was also notified at home. The low flow durations were eight and ten minutes, respectively. Plant management voluntarily shutdown Unit 3 after the second occurrence until the grass/algae situation could be further assessed and evaluated, and until corrective actions could be implemented. The Technical Specification 3.0.3 entries and subsequent exits did not require a shutdown.

Each unit's ICW system has three pumps which discharge to a common header and then the flow splits to two redundant loops. Another two lines supply ICW flow to the TPCW (non-safety-related) heat exchangers. Each of the two redundant ICW loops have a full flow mesh-type basket strainer prior to a common discharge into the three CCW heat exchanger inlets. These basket strainers can be backwashed or mechanically cleaned by removing the strainer from service. The backwashing is normally effective, unless the mesh becomes matted excessively with this grass/algae material. Mechanical cleaning requires the removal of the strainer top works, and thus results in more out-of-service time.

During procedure ONOP-11 implementation operators provide the clearance boundaries with the use of locks and constant surveillance. This included the monitoring of the local ICW/CCW flow indicators. The licensee initiated condition report No. 96-152 and re-convened the ERT which had previously evaluated the January 31, 1996 similar event. The ERT concluded the following: (1) Screen and screen wash performance had improved based on previous corrective actions; (2) Basket strainers could only be effectively cleaned by mechanical means; (3) Cooling canal cleaning and surface grass removal had limited effectiveness; and (4) Weir pit trash and decayed grass was probably forced out the structure's holes and into the 3A1/3A2 wells. The licensee concluded root cause to be failure of the weir pit to retain the decomposing grass and algae that were previously discharged (backwashed) to the weir pit. This small sized material escaped the weir pit through the designed flow holes and entered the intake, travelling through the screen mesh associated with the travelling screens. Thus, the grass and algae affected the ICW and circulating water systems. Contributing causes included inadequate weir pit cleaning, degraded performance of 3A1 screen mesh (older type), low speed screen tripping circuit, no high range basket strainer DP device, and the east canals floating and submerged grass/algae.

Licensee corrective actions included:

- PNSC review and approval of ERT/condition report,
- Plant management approval for Unit 3 restart on February 19, 1996,
- The weir pit was inspected and cleaned with a clamshell and a vacuum cleaner to remove all grass and sediment,
- The discharge of the screen wash was directed to the discharge drain pipe,
- The older corrugated mesh baskets in the 3A1 travelling screen were replaced,
- The low speed trip of the Units 3 and 4 travelling screens were defeated,
- The Units 3 and 4 travelling screens were test run in fast speed,
- High range differential pressure instruments were installed on Unit 3 and Unit 4 ICW/CCW basket strainers,
- Two additional booms and slime suckers were installed in the canal system,

- The canal weed removal machine was moved to the shallow area of the key (east) canal,

- Operations procedures were enhanced to include additional considerations for use prior to starting ICW pumps and use of high range differential pressure instruments for use in determining the more fouled ICW/CCW basket strainer on either unit,

- Engineering provided a safety evaluation (JPN-PTN-SENP-96-9) for use in valving in and out basket strainers which allows for up to five minutes of low flow conditions and to consider the ICW system operable,

- Training Brief No. 603 was written and crews were trained on the event and corrective actions,

- A study and recommendations for removal of grass from the trash pit is underway,

- Initiated an REA to provide scope and estimate for ICW flow indication in the control room,

- Evaluated specific conditions achieved during both low flow events in order to determine if the design basis of the ICW system was still being met (JPN-PTN-SENP-96-9), and

- Submitted voluntary LER 96-01 on February 29, 1996.

The inspector received notifications of the above events and responded to the site early in the morning of February 16, 1996. The inspector verified licensee actions, reviewed log entries and notifications, discussed the event with on shift personnel, and monitored ERT activities. The inspector also toured the canal system noting large grass accumulations in the east (return) canals. A walkdown of the intake, including the screen wash and weir pit, was also performed. The inspector attended ERT meetings and participated in a conference call with Regional management and NRR on February 16, 1996. The licensee's ERT/condition report, safety evaluations, LER 96-01, and the training brief were reviewed. The inspector also attended the PNSC and management meetings which authorized restart. Restart activities were also monitored. The inspector also reviewed UFSAR section 2C.

The inspector concluded that corrective actions initiated after the two previous events were somewhat effective in minimizing overall plant effects. The time of the ICW flow perturbations and the degree was lessened. The inspector concluded that root cause of the first (March 1995) event was due to heavy rain in the canal system combined with ineffective grass removal by the screen wash system. Further, root cause of the January and February 1996 events was most probably due to inadequate cleaning of the weir

pit which allowed the decomposed material to enter into the ICW/circulating water systems.

The licensee's corrective actions appeared to be complete and thorough. The ERT investigation was very professional, including an aggressive questioning attitude displayed by team members. Further, licensee management considered these events serious, and voluntarily shutdown the affected unit (Unit 3) until the root cause and corrective actions were completed. LER 96-01 is considered closed.

O1.2 Unit 4 Shutdown and Cooldown, and Reactor Vessel Draindown

The licensee commenced power reduction for the Unit 4 refueling outage on March 1, 1996 to 60% power. Subsequently on March 4, 1996, at 12:14 a.m., the generator output breakers were opened. Operators shut down the reactor, entering Mode 3 at 12:23 a.m. Subsequent testing and cooldown activities were performed and the unit entered Mode 4 at 1:00 p.m. on March 4, 1996, and Mode 5 at 6:20 p.m. on March 4, 1996. Mode 6 was entered at 7:20 p.m. on March 9, 1996, when the licensee commenced reactor vessel head stud detensioning.

The inspectors observed portions of the shutdown, cooldown, and related testing activities. The inspectors verified that these evolutions were performed in accordance with approved procedures, that appropriate oversight was present, and that technical specification requirements were followed. Overall, observed activities were well performed and safely conducted with strong oversight. The shutdown was performed in accordance with procedure 4-GOP-103, Power Operations to Hot Standby. Further, the licensee performed a one time OTSC (number 119-96) to procedure 4-GOP-103 to manually trip the reactor at less than 5% power. The purpose of the OTSC was to address and gather information pursuant to an industry concern relative to incomplete rod insertion events that had recently occurred at several other sites. This issue is also discussed in detail in section O5.2 of this report.

With the unit at approximately 1% power, at 12:23 a.m. on March 4, 1996, a manual reactor trip was initiated from the control room. Control banks A, B, C and shutdown banks A and B were fully withdrawn and control bank D was at 74 steps prior to the trip. All rods successfully inserted into the core following the trip as verified through the analog RPI system. Following the shutdown, the two source range nuclear instruments N 31 and N 32 had to be manually energized (below P-6, 10E-10 amps) due to potential under-compensation of intermediate range nuclear instruments N 35 and N 36. A PWO was originated to troubleshoot and repair the intermediate range instruments.

The inspector concluded that the operator performance during the shutdown was deliberate and professional. Further, the NPS conducted procedure 0-ADM-217, Conduct of Infrequently Performed Tests or Evolution briefings prior to initiation of the shutdown as well as the reactor trip.

In order to accommodate RPV head detensioning, the RCS was drained to a level of 1.5 feet below the RPV flange. Reduced inventory or midloop operation condition exists at 3.0 feet or more, below the RPV flange. Therefore, the licensee did not technically go into midloop conditions until after the complete core offload. However, the inspectors reviewed the following documents:

- Generic Letter No. 88-17, Loss of Decay Heat Removal, and the licensee's responses to this generic letter;

- Operating procedures 4-OP-041.7, Draining the Reactor Coolant System; 4-OP-041.9, Reduced Inventory Operations; and 4-OP-201, Filling/Draining the Refueling Cavity and the SFP Transfer Canal;

- Abnormal operating procedure 4-ONOP-052, Loss of RHR;

- Surveillance procedures 4-OSP-051.14, Reduced Inventory Containment Penetration Alignment Verification; and 4-OSP-201.1, RCO Daily Logs;

- Various plant drawings;

- Training lesson plans and system description No. 007, Reactor Coolant System;

- Control room log books; and

- Refueling outage schedules.

Prior to the draindown evolution, the licensee conducted special briefings as required by procedure 0-ADM-217, Conduct of Infrequently Performed Tests or Evolutions. Level was maintained at approximately 49% on the remote reactor draindown indicators LI-6421 and LI-6423. This corresponded to 1.5 feet below the RPV flange.

The inspectors verified that redundant RCS level indications were available and were being monitored by control room operators. Level devices LI-6421 and LI-6423 provided remote readout in the control room, and a tygon level tube (level device LI-6422) provided local indication in the containment. The inspectors verified that these devices were available, being used, and recorded accordingly and that they indicated within their allowable tolerances.

The inspectors concluded that the licensee was proactive in reducing risk and demonstrated conservatism in its decision to complete core offload prior to entering reduced inventory and midloop operations for RCP and steam generator work. Further, licensee actions to drain the RCS were effectively conducted with good procedural compliance and with strong oversight.

O1.3 Unit 4 Core Offload and Reload

The Unit 4 reactor core was completely offloaded into the SFP during the period March 13-15, 1996. The licensee implemented procedure 4-OP-040.2, Refueling Core Shuffle. Procedures 4-OP-038.1, Preparations for Refueling Activities, and 4-OP-038.9, Refueling Activities Check Off List, were used to ensure that prerequisites, precautions, limitations, and guidance were appropriate for core alteration activities.

During the period March 22-25, 1996, the licensee reloaded the reactor core for Cycle 16. This was done per procedure 96-TP-012 Unit 4 Cycle 16 Core Reload. During the reload, a few assemblies were discovered to be moderately bowed. This required extra time and a number of fuel assembly move deviations. The inspectors verified that these deviations were performed per procedure 4-OP-040.2, Attachment 2.

The inspectors reviewed the above mentioned procedures, refueling, technical specification, operating procedures for each refueling station, UFSAR section 9.5,condition reports associated with equipment problems, and operating and reactor engineering logs. (See section R1.4 regarding high radiation levels from the SFP transfer canal.) The inspectors witnessed portions of the Unit 4 refueling activities from the following locations:

- RCO station in the control room;
- reactor engineer station in the control room;
- RCO, SRO, and vendor stations on the manipulator bridge;
- containment upender and transfer cart station;
- SFP upender and transfer cart station, and
- RCO station on the SFP bridge.

On March 14, 1996, at about 1:00 p.m., the inspector noted that the assigned Unit 3 ANPS was observing the Unit 4 SFP activities. The NPS and the Unit 4 ANPS were present in the control room and another ANPS was present in the work control center. Although allowed by procedures and NRC requirements, the inspector questioned this practice. Operations management also did not agree with this use of the Unit 3 ANPS, and actions were taken to

immediately stop this practice. The inspector verified that Unit 3 SRO oversight, including command and control, was maintained.

During these core alterations, the inspectors reviewed the implementation of procedure TP-1201, Control of the Personnel Hatch During Core Alterations. This TP implemented the revised Technical Specification 3.9.4 requirements (per amendments 123 and 167). The change allowed the personnel airlock doors to remain open as long as a person was designated to remove potential blockage devices (maximum of five) and to close one door in 15 minutes.

For those evolutions that were directly observed, the inspectors noted that communications were formal, teamwork was effective, and procedure usage and compliance was strong. However, an error occurred when preparing the SFP bridge (see section M2.5). Implementation of the revised personnel airlock requirements was appropriate. Overall, observed core alteration activities were professionally and notwithstanding the above comments, efficiently performed.

02 Operational Status of Facilities and Equipment

02.1 Unit 3 Rod Position Indication

On February 22, 1996, from 2:25 a.m. to 3:05 a.m., three Unit 3 rod bank D IRPIs (D8, M8, and H4) indicated greater than 12 steps from their demand position. The licensee entered Technical Specification 3.0.3 due to more than one rod IRPI out-of-specification (e.g., Technical Specification 3.1.3.2). The licensee verified rod position by performing a flux map, re-adjusted the affected IRPIs, and exited Technical Specification 3.0.3 when rod positions were within specification. Similar events have occurred in 1992 and 1994(reference Unit 4 LER 92-01 and Unit 4 LER 94-03). As a result of the 1994 LER, the licensee submitted a licensing amendment request to allow 18 step IRPI deviations when less than 90% power.

The licensee concluded that the cause of the deviation was IRPI variation with temperature especially after a power change. Operators had just raised Unit 3 power from 70% to 100%.

The inspector reviewed the event, logs, UFSAR section 7.2, and the LER. In addition, the event was discussed with cognizant personnel. The LER was noted to be appropriately written. Based on inspection and review, the LER is closed.

02.2 4B Safety Injection Pump Drain Rig Controls

During a routine tour on March 18, 1996, the inspector noted that drain rigs were installed on the 4B HHSI pump and had been since March 17, 1996. The 4A HHSI pump was operable; however, the 4A

EDG was OOS for maintenance. Unit 3 was operating at 100% power and Unit 4 was defueled. As required by the Technical Specification 3.5.2, Unit 3 required three operable HHSI pumps powered from their respective EDGs. Both the 3A and 3B HHSI pumps, and their EDGs were operable. Thus, no technical specification operability nor action statement requirements were violated.

The inspector discussed this issue with the system engineer and operations personnel. Condition report No. 96-402 was written and the licensee's investigation noted that operations had approved the staging and installation of the drain rigs per procedure O-ADM-222, Drain and Vent Rig Controls. However, it was unclear whether the fittings, tygon hoses, etc. had been approved by management and engineering. When the inspector notified the NPS at 8:00 a.m. on March 19, 1996, actions were immediately initiated to remove the drain rigs.

Procedure O-ADM-222 step 5.2.1 caution states that installation of vent and drain rigs should only be on equipment which has been declared OOS. On March 18, 1996, drain rig equipment was noted to be installed on the 4B HHSI pump which was in service for Unit 3. This is considered a weakness because management wasn't cognizant of the drain rig installations. Further, engineering review determined the 4B HHSI pump to be operable. No violations were identified.

04 Operator Knowledge and Performance

04.1 Unit 3 Reactor Trip

The Unit 3 reactor automatically tripped from 60% at 11:34 p.m. on February 9, 1996. The trip signal was from a turbine trip/reactor trip above P-7 (e.g. 10% power). The turbine trip was initiated when the 3C S/G level exceeded the high-high level trip setpoint of 80% narrow range. The licensee had stopped the 3B SGFP due to abnormal indications on the check valve (see section M2.2), and the valve failed to fully seat. This condition allowed the running 3A SGFP flow to become diverted from the feedwater header and a low level transient occurred on all S/Gs. Operators adequately responded to this low level problem. However, five minutes after the 3B SGFP was stopped, a high level transient was not contained on the 3C S/G, and a high level trip subsequently occurred. Seconds before the automatic trip, a manual trip was ordered; however, the automatic trip occurred first.

Conditions were normal on the trip. The RPS functioned normally and all rods inserted to shutdown the reactor. All three steam driven AFW pumps started and injected as expected. A feedwater isolation also occurred on the high S/G levels. Primary pressure and temperature were controlled as expected. Operators entered and implemented the appropriate EOPs. When a SGFP was restored,

the AFW pumps were shutdown. During shutdown of the A AFW pump, an overspeed trip occurred (see section E2.1.) The licensee made a 10 CFR 50.72 notification at 12:35 a.m.and notified the inspector at home on February 10, 1996. The licensee convened an ERT and initiated Condition Report No. 96-134.

The licensee concluded that the trip was caused when operators did not effectively monitor nor control the 3C S/G level when recovering from the initial low level and subsequent high level transients. Further, management's decision to perform the SGFP evolutions at 60% power and degraded components (e.g., 3B SGFP discharge check valve and 3C S/G blowdown controller) contributed to this event. A post trip review per procedure O-ADM-511, Post Trip Review, was evaluated and approved by PNSC on February 10, 1996.

Corrective actions included the following items:

- Verification that the 3C S/G level control system was functioning,

- Review of the "A" AFW overspeed trip (reference Condition Report No. 96-135 and section E2.1 of this report),

- Discussions with each crew relative to the event and associated weaknesses by Operations Management,

- Training evaluations relative to adding scenarios which involve operators to respond to S/G level control problems,

- Reviewed of the command and control functions relative to manual trip criteria by Operations management ,

- Repair of the 3B SGFP check valve (section M2.2),

- Repair of the 3C S/G blowdown valve timing and satisfactory check of the Unit 4 valves,

- Submittal of LER 96-02 and performance of HPES evaluation,

- Performance of an independent QA assessment,

- Performance of a containment leak inspection and adjustment of packing for three valves with dry boric acid leaks, and

- Performance of a site critique and lessons learned video taped session.

The inspector responded to site, monitored control room post trip response. The inspector also evaluated the ERT report, the QA assessment, the condition report, and the post trip review followup. The onshift operators were interviewed, and control

room indications, chart recorder traces, alarms, sequence of events, and EOP implementation were independently verified. The inspector noted that five minutes had elapsed from the initial S/G low level transient to the high level S/G trip. This should have been adequate time to respond to and correct the S/G level abnormalities. The inspector noted that two extra operators were assigned to the unit, dedicated to monitor and to control S/G levels. Further, an operations management representative was present in the control room to provide oversight. The inspector noted that the evolution was pre-briefed for both shifts (peak and midnight) involved. (A shift change occurred at 11:00 p.m.). The NPS and one RCO were new to the evolution, and the ANPS and two RCOs stayed over after shift change.

The inspector reviewed management's decision to conduct the acoustic monitoring and SGFP pump operations, and the related risk involved. The licensee considered this evolution not to be high risk based on successful performance given similar indications on Unit 4 in 1993 (reference NRC Inspection Report 50-250,251/93-24). Vendor information and related experiences had concluded that the check valve disc should close even with one hinge pin missing. However, the licensee discussed contingencies and actions if the check valve did not close until the MOV (SGFP discharge) stroked close on a SGFP pump stop signal. This included extra personnel, management oversight, pre-evolution briefings, etc.

The inspector concluded that the licensee's decision did have reasonable basis; however, the evolution was not without some element of risk. Further, the inspector noted that operator performance was less than optimal. Although, the transient was caused by BOP equipment problems, operators had an opportunity to control the S/G level transients and to prevent a reactor trip. The licensee's investigation was deemed as being thorough and was a very self-critical assessment. Corrective actions appeared appropriate. Further, a QA assessment (QR No. 96-56) was very thorough and self-critical. That assessment noted weaknesses in the pre-evolution briefing, command and control, inaccurate prediction by management of risk, poor operator performance in controlling S/G levels, and weaknesses in assessing the generic SGFP check valve issues in 1993.

05 Operator Training and Qualification

05.1 Outage Related Training

The inspector reviewed the licensee's training conducted to support the Unit 4 Cycle 16 refueling outage. The inspector noted that training included the following:

- Licensed operator training, including simulator training, regarding RHR, decay heat removal, and actions and procedures necessary to combat a loss of RHR and/or coolant.

- Outage and plant management conducted meetings addressing various items, including draining control, PC/Ms, procedure changes, LLRTs, MOV, ADMs, RCPs, containment, operating unit, electrical work, clearances, shift assignments, etc.

- Training briefs for outage related PC/Ms.

The inspector attended selected briefings and reviewed documentation. Further, the inspector questioned selected operators regarding their knowledge. The inspector concluded that training was effective.

05.2 NRC Bulletin 96-01

The inspector reviewed the licensee's actions regarding training as required by NRC Bulletin 96-01, Control Rod Insertion Problems, dated March 8, 1996. The inspector noted that the licensee received the bulletin promptly on the evening of March 8, 1996. Condition Report 96-272 was written on March 9, 1996, and the licensee prepared Training Brief number 618, also on March 9, 1996. The brief promulgated information on recent industry events regarding control rod failures, on actions taken as required by EOPs and ONOPs, training to be conducted, and other plant actions. These included information that Turkey Point uses 15x15 Westinghouse fuel with a 24 inch dashpot region. (The fuel experiencing slow rod drop times were 17x17 fuel.) Recent Turkey Point experience with a Unit 3 trip (section 04.1) and a Unit 4 trip to complete the shutdown (section 01.2) demonstrated appropriate rod insertion. Further, satisfactory results were noted on the as found and as left drag testing done on Unit 4 during the outage.

The licensee performed classroom and simulator training for licensed operators during the week of March 17, 1996. The inspector reviewed training, noting the following EOP/ONOP:

- procedures 3/4-EOP-E-0, Reactor Trip or Safety Injection,

- procedures 3/4-EOP-ES-0.1, Reactor Trip Response,

- procedures 3/4-EOP-F-0, Critical Safety Function Status Trees,

- procedures 3/4-EOP-FR-S.1, Response to Nuclear Power Generation/ATWS, and

- procedures 3/4-ONOP-046.1, Emergency Boration.

The inspector concluded that the above procedures appropriately addressed the conditions delineated in the bulletin. Further, operators were appropriately and effectively trained as required by action 2 of the bulletin.

07 Quality Assurance in Operations

07.1 Unit 4 Refueling Outage Oversight and Risk

The inspectors reviewed the licensee controls and oversight in effect during the Unit 4 refueling outage. This included the implementation of administrative procedure O-ADM-051, Outage Risk Assessment and Control. This ADM required a risk assessment team to review the refueling schedule, switchyard work, higher risk evolutions, and key safe-shutdown functions and to maintain a risk information notebook. The team was comprised of engineering, outage, operations, and maintenance personnel. Minimum required equipment was addressed in the ADM enclosures. The inspectors verified that important equipment was maintained operable or available as necessary. Deviations from the ADM requirements were accomplished by the use of an approved Temporary Change Notice (TCN). The enclosures were broken into two parts: large decay heat load (<10 days from shutdown) and reduced decay heat load (>10 days from shutdown). The schedule was to floodup the cavity (after head removal) at about the 6th day and to begin core off-load on the 7th day, 163 hours after shutdown.

The inspectors reviewed the safety equipment necessary to support decay heat removal from Mode 3 to Mode 6 with the vessel and cavity flooded. In Mode 3, all safety equipment (RCS, ECCS, S/Gs, AC/DC, AFW, and ICW/CCW systems) are required to be operable by both technical specification and ADM requirements. In Mode 4, the licensee maintained all safety equipment operable above any requirements. For example, all RHR and RCS loops, all ECCS, AFW (from the other unit), and SGFPs were maintained operable even though not required by the Technical Specifications. Further, in Mode 5 (RCS filled and RCS not filled) all safety equipment was also maintained operable. For example, all RCS loops, all RHR, all AC/DC trains, all EDGs and off-site power, and AFW from the other unit were available. Likewise, in Mode 6 (not flooded), all RHR and support systems, AC/DC trains, all EDGs and offsite power, and AFW from the other unit was maintained operable.

Although not required by the Technical Specifications, the licensee maintained ECCS available for Modes 4, 5, and 6. For example, the cold leg accumulators, HHSI, and the charging system were available for injection, makeup, and RCS feed/bleed operations. However, one difference this outage was that HHSI was temporarily isolated for about two shifts (in Mode 5) in order to accommodate a flange installation to support a modification to the BIT (see section E2.3). This was accomplished by use of a TCN approved by both the risk team and management.

Once the cavity was flooded to support core offload, the 4A train equipment was removed from service as allowed by Technical Specifications. This 4A train outage included the 4A EDG, the 4A

4KV, the 4A RHR and support systems, etc.) Since this occurred in the first 10 days, another TCN was written and approved by both the risk team and management.

The inspectors verified that the Unit 4 outage plan was implemented as scheduled and that Technical Specification and ADM requirements were met. The inspectors noted conservatism relative to equipment made available to remove decay heat as the licensee transitioned from hot standby (Mode 3) to refueling (Mode 6). Further, the licensee maintained RPV level above RCS reduced inventory and RCS midloop levels. The licensee continues not to go to midloop with the core loaded in the vessel. This has been true for the past several years. Another good practice noted was system engineering involvement. Periodically, and at least weekly, the system engineers walked down their systems and wrote a report. These reports as well as the TCNs were maintained in risk assessment notebooks located both in the control room and in the outage conference room.

The inspectors noted that the licensee assigned shift directors to cover the outage around the clock. Senior plant personnel and department managers were assigned this shift direction function. These shift directors provided oversight and maintained status of the refueling outage activities. They also conducted the periodic outage status meetings. The inspectors noted that these shift directors were involved in the field and directly involved in containment activities.

The inspectors noted that QA personnel were involved in outage activities including core offload and reload, core verification, containment tours, EDG maintenance, PC/M implementation, and control rod and integrated safeguards testing. QA findings were discussed with the appropriate personnel and were documented in QA audit and surveillance reports.

Control room oversight was strengthened during the outages. The operating shifts were modified from a six-shift to a four-shift rotation. This provided extra NPSs and ANPSs on each shift to provide SRO coverage for refueling and other outage-related activities. Further, operations management provided additional oversight for key refueling activities, e.g., draindown, core alteration, integrated safeguards testing, unit restart, etc.

In conclusion, the inspectors noted strong oversight of Unit 4 during its refueling outage. Weaknesses previously noted in knowledge, risk, and the overall effects of shared systems, their outages, and the effects on the operating unit (reference NRC Inspection Report 50-250,251/95-16) were appropriately addressed.

II. Maintenance

Inspection Scope (61726, 73753, and 62703)

The inspectors verified that station maintenance and surveillance testing activities associated with safety-related systems and components were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and the technical specifications. They accomplished this by observing maintenance and surveillance testing activities, performing detailed technical procedure reviews, and reviewing completed maintenance and surveillance documents.

Inspection Findings

M1 Conduct of Maintenance

The inspectors witnessed/reviewed portions of the following maintenance activities in progress:

- SGFP check valve repairs/inspections (sections O4.1 and M2.2),
- Rod control system troubleshooting (section M2.3)
- WO 95003154 and 2569, Repair of Unit 4 Stop Valve 4-821 in the Line Supplying Demineralized Water to the Spent Fuel Pit (section M1.1)
- WO 96004233, Change Pressure Controls for Auto Start of Unit 4 Standby CCW Pump (section M1.10)
- Unit 4 RPV disassembly (section M1.9)
- EDG 4A and 4B overhauls (section M1.2)
- Unit Turbine generator overhaul (section M1.7)
- Unit 4 S/G plug replacements (section M1.8)
- POV-3-4882 repair (section M2.7)
- WO 95003804, Repair of Unit 3 SFP Skimmer Hoses (section M1.1)
- WO 95031971, Modification of Unit 4 Modification of Main Steam Flow Instrument Taps (section M1.11)
- Refurbishment of Unit 4 Feedwater and Steam Generator Level HAGAN Controller Modules (section M2.6)

- Flow Accelerated Corrosion Inspections Planned for the Upcoming Unit 4 Outage (section M1.6)

For those maintenance activities observed, the inspectors determined that the activities were conducted in a satisfactory manner and that the work was properly performed in accordance with approved maintenance work orders.

The inspectors witnessed/reviewed portions of the following test activities:

- Auxiliary Feedwater logic testing (section M6.2),
- Procedure 4-OSP-030.46 Component Cooling Water Heat Exchanger Performance Test (section M1.12)
- 4A and 4B EDG testing (section M1.2)

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the technical specifications.

M1.1 Unit 3 and 4 Spent Fuel Pool Outage Activities

WO 95003154 covered replacement of the stem and bonnet for Unit 4 valve 4-821 because of a broken stem. Since the valve could not be isolated from the SFP, freeze seals (on a 2" line and on an 8" line) were used for isolation and the SFP Cooling System was taken out of service. WO 96002569 covered establishing and maintaining the freeze seals. The inspectors observed the establishment and maintenance of the freeze seals, replacement of the valve bonnet, diaphragm, and stem, and Liquid Penetrant examination of the pipes after thawing of the seals. In addition, the following documents associated with the work activities were reviewed:

- WOs 95003154 and WO 96002569,
- Safety Evaluation JPN-PTN-SENS-96-012, Revision 0, Freeze Seal Installation to Support Maintenance Activities on 4-821,
- Procedure 0-GMM-102.5, Revision 09/04/95, Freeze Seal Application,
- Technical Specification 3/4.9.11,
- UFSAR Sections 9.3.3 and Appendix 14D, and
- NDE qualification records for the examiners who performed inspections of the freeze seal areas after thawing of the seals.

In general, the work was well planned and executed. However, the inspector noted some problems. During PT inspection of the 2" pipe after thawing of the freeze seal, the inspector noted that the penetrant material did not properly wet the surface of the pipe. Paragraph 5.2.3 of the applicable procedure Revision 6, Liquid Penetrant Examination, required that the surface remain wet with penetrant throughout the dwell time. After a minute or two of the dwell time had elapsed and the examiner had not added additional penetrant to keep the surface wetted, the inspectors questioned the validity of the test. After questioning by the inspectors, the examiner applied additional penetrant and restarted the dwell time. This resulted in an acceptable examination.

Although an adequate examination was performed, the observation raised questions relative to the adequacy of the technique and the QC examiner's qualifications. Based on the questions raised by the inspectors, the QC Supervisor conducted an evaluation and reported the following results:

- The QC examiner was questioned relative to the technique observed and was aware of the need to keep the surface wetted for the full duration of the dwell time. He indicated that common practice was to apply the penetrant, start filling out the paper work, and then after a minute or two check the pipe to see that it was properly wetted. If the pipe was not properly wetted, more penetrant would be applied and the dwell time extended to ensure the surface had been wetted for the proper time.

- The QC examiner was re-tested by the Level III Examiner, including performance testing and his knowledge of procedure requirements. The Level III examiner did not find any problem with the QC examiners qualification and knowledge of procedure requirements.

- Three other PT examiners were questioned relative to their knowledge and practices relative to keeping the surface wet with penetrant throughout the dwell time. No problems were identified with these examiners.

Results of the above evaluation were reported to the inspectors on March 6, 1996. Based on the above, this issue is considered resolved.

The inspector also noted a weakness in the freeze seal procedure (0-GMM-102.5). Some of the guidance in the procedure only covered piping up to 5" diameter. For the above stop valve repair, a freeze seal was used on an 8" line. The guidance provided information relative to the maximum flow inside the pipe and the approximate amount of nitrogen needed to establish a seal. This guidance was not critical for the job observed. However, for consistency and to provide the proper guidance for all

possibilities, larger diameter piping should be included in the procedure. The licensee agreed with this observation and indicated the procedure would be revised to include larger piping.

WO 95003805 covered repair of the Unit 3 SFP Skimmer hoses. The inspectors observed portions of this work, including Operations measurement of SFP level and temperature, and verified compliance with the following associated documents:

- WO 95003895,
- Clearance 3-96-02-150,
- Safety Evaluation JPN-PTN-SEMS-95-060, Revision 0, The Temporary Lowering of Unit 3 SFP Water Level for Maintenance Activities,
- Operations log of SFP level and temperature,
- Technical Specification 3/4.9.11, and
- UFSAR Sections 9.3.3, Appendix 14D, Appendix 5A, Table 11.2-5, and 5.2.3.

This job was successfully completed with no problems. Personnel appeared to be well qualified for the task being performed. However, the inspector noted the following weakness. The WO was originally written to replace the skimmer hoses from above the SFP using deep water gloves. Because of the distance from the top of the SFP down to the skimmers, the decision was made to place a small fiberglass boat in the SFP to support the worker. During preparations for the work, the inspector noted that the WO did not address placing the boat in the SFP. When questioned by the inspectors, Maintenance Supervision stated that they were aware that the WO would need changing to cover use of the boat. Later, before start of the job, the inspectors noted that the WO had been changed to add a line stating that the boat would be used. However, no instructions or precautions for use of the boat were included in the WO. In addition, although the use of the boat was evaluated by Licensing and Engineering, the evaluation was not formally documented. As noted above, the job was successfully completed even though documentation was weak.

M1.2 Unit 4 Emergency Diesel Generator Preventative Maintenance and Testing

The inspectors reviewed and observed activities associated with the 4A and 4B EDG preventative maintenance as required by technical specifications. The licensee's inspection of the EDGs was conducted in accordance with various procedures including the 18, 36, and 72 month inspections. The inspections were performed by contractor personnel with assistance from onsite engineering

and maintenance groups with offsite support. The EDG inspections did not reveal any notable discrepancies requiring further investigation. Following the completion of the inspection, the 4A and 4B EDGs were tested and returned to service. During the 4A EDG PMT, problems were observed in a temperature switch and a lockout relay. Poor maintenance was noted by I&C and lack of PM was noted by electricians. The licensee identified these issues, and took prompt and appropriate corrective actions. Subsequent testing was successful.

The inspectors also reviewed the QA surveillance activity that was performed to review activities associated with the EDG inspections. QA personnel concluded that maintenance activities were appropriate. The inspectors concluded that the 4A and 4B EDG preventative maintenance and testing activities were satisfactorily completed. In addition, appropriate procedures and precautions were followed and activities were executed in a meticulous manner. The licensee appropriately addressed the above mentioned weakness.

M1.3 Motor Operated Valve Testing

The inspector reviewed the scope of MOV related activities scheduled for the Unit 4 Cycle 16 refueling outage. The licensee planned to perform 35 "MOVATS" tests, two differential pressure tests, approximately 25 MOV overhauls, approximately 20 grease inspections, and 10 preventative maintenance inspections. The inspector received and discussed several condition reports that were generated as a result of these MOV activities. The inspector concluded that the MOV coordinator/responsible engineer was knowledgeable and maintained cognizance and ownership of the MOV related activities ongoing during this outage.

M1.4 Unit 4 Power-Operated Relief and Block Valves Maintenance

The licensee overhauled one Unit 4 PORV (PCV-4-455C) per procedure O-PMM-041.1, Reactor Coolant System Power Operated Relief Valves Overhaul. The PORVs are two-inch, Copes-Vulcan, air-operated, plug valves with an internal cage. The PORVs have had historical seat leakage problems. The licensee also overhauled both Unit 4 PORV block valves (MOV-3-535 and 536) per procedure O-PMM-041.3, Reactor Coolant System Velan Bolted Bonnet Gate Valve Overhaul.

The inspectors reviewed the procedures, PWOs and other related documentation, discussed the work with maintenance personnel, and inspected the valves in the pressurizer cubicle. The inspectors concluded that procedure and PWO implementation were appropriate.

M1.5 Local Leak Rate Testing

The inspector observed and discussed ongoing local leak rate testing that was performed on Unit 4 during the outage. As of the

end of the current report period, as-found and as-left leak rate tests were still ongoing. The inspector did review several condition reports that were generated as a result of these on-going tests. The inspector plans to review final as-found and as-left results following completion. The inspector concluded that the IST coordinator and supervisor were knowledgeable and responsive to inspector questions. Further, the condition report system was appropriately utilized to document failures.

.M1.6 Flow Accelerated Corrosion Program and Plans

In response to Generic Letter 89-08, Erosion/Corrosion Pipe Wall Thinning, licensees have implemented long term Erosion/Corrosion or FAC programs. The current inspection evaluated the status of various aspects of the Turkey Point Program including the scope of inspections planned for the current Unit 4 outage. The following is a summary of the inspection activities and results:

- The inspectors reviewed the following documents to verify the scope of the program for the current Unit 4 outage and that a comprehensive program is in place:

  - JPN-CSI-FAC-100, Revision 5, Corporate Long-Term Flow-Accelerated Corrosion Monitoring Program.

  - Turkey Point Procedure O-ADM-530, Revision 1/3/96, Flow Accelerated Corrosion Inspection Implementation Program.

  - CSI-FAC-PTN-4-16P, Revision 1, Winter 1996 Outage Cycle 16 Flow Accelerated Corrosion Outage Plan.

- The large-bore program includes approximately 2200 components and is based on modeling by CHECKMATE, industry experience, plant experience and engineering judgement. EPRI CHECKMATE 1.1b and CHEC-NDE were being used.

- A small-bore program has been initiated with inspection areas selected based on safety-related susceptible piping, non-isoable piping, and failure history. Inspections have been performed for one outage for each Unit.

- The most recent through-wall leaks occurred in Unit 3 MSR Drains in 1993 and 1994. This piping, from the MSR Drain Pots to the nozzles at the Heater Drain Tanks, has now been replaced with Cr-Mo material for both Units 3 and 4.

- For the current outage, 129 large-bore component inspections, including 16 baseline inspections, and 44 small-bore elbow inspections have or will be performed. Some safety-related feedwater components in the containment are included. After this inspection, 100% of the accessible

feedwater piping in the containment, from the expander at the SG to the containment penetration, will have been inspected for both Units 3 and 4.

As of March 23, 1996, the licensee had completed almost all of the inspections, including an inspection resulting in an expanded scope. Approximately 35 condition reports were generated as a result of FAC related activities. Most significant of these were related to observed thinning of a portion of a main steam line down stream of the MSIV. The licensee plans to disposition each of the 35 generated condition reports prior to the end of the refueling outage.

Based on the above review, the inspectors concluded that the licensee had a detailed, pro-active FAC program in place. The number and mix of components being inspected during the outage appeared to be appropriate.

M1.7 Unit 4 Turbine-Generator Overhaul and Secondary Plant Modifications

The licensee performed Unit 4 turbine-generator maintenance including main generator and exciter removal, inspections, modifications, and refurbishments, and other related preventive and corrective maintenance activities. Further, an uprate related PC/M was performed to stake the main condenser tubes. A number of PC/Ms (including 95-155, 95-152 and 95-117) were also completed.

The inspector reviewed work and selected PC/M packages, UFSAR Chapter 10, and observed maintenance and modifications in the field. The inspectors noted excellent supervisory oversight, and positive control of the turbine heavy load lifting and rigging activities.

M1.8 Unit 4 Steam Generator Inspection and Cleaning Activities

During the current Unit 4 refueling outage, the licensee performed inspections, tube plug replacements, and secondary side sludge lancing associated with all three steam generators. This included involvement among FPL corporate, site, and contractor organizations. In addition, a number hot leg "alloy 600" Westinghouse mechanical tube plugs were replaced due to industry problems. This was performed as required by an NRC commitment per CTRAC No. 95-0033. Steam generator inspections and associated activities were performed in accordance with approved program plans. The chemistry department retained overall responsibility for this steam generator work.

Based on previous inspections with minimal tube plugging, the licensee did not perform any eddy current or bobbin coil inspections of the tubes in the three steam generators during this

refueling outage. This was based on licensee letters of January 16 and February 27, 1996 and NRC letter of March 18, 1996.

On March 15, 1996, a nozzle dam was dropped and it broke a light inside the 4B S/G hot leg. Condition report No. 96-361 and Safety Evaluation (JPN-PTN-SEMS-96-022) were initiated. The licensee removed the material and concluded that any remaining material was acceptable.

The inspectors observed a sampling of the above mentioned activities including field work, data retrieval, and assessment. Inspection procedures were also reviewed, and personnel involved in the steam generator activities were interviewed. The inspectors also reviewed UFSAR Chapter 4.2, 4B and 4C. The inspectors concluded that the licensee's engineering and chemistry personnel were effectively involved in all phases of these activities. Strong secondary chemistry programs and controls have resulted in minimal pluggable steam generator tubes. The licensee appropriately identified and addressed the FME issue.

M1.9 Unit 4 Reactor Vessel Work

During the Unit 4 refueling outage, the inspectors observed portions of the reactor vessel work including: reactor head interferences removal and replacement, reactor head detensioning and tensioning, upper internals lifts, cavity seal ring installation and removal, and other related activities. The inspectors verified that maintenance procedures were being used, that an appropriate level of supervision was present, that operations personnel were cognizant of and appropriately approved those required activities, and that activities were safety conducted. The inspector also reviewed UFSAR Chapter 3.

The inspectors concluded that for these observed activities, the licensee was conducting safe and efficient evolutions. Overall, licensee performance was noteworthy for these vessel related maintenance and testing activities.

As part of the cavity floodup process, the licensee utilizes a filtration system to purify the water to ensure clarity. UFSAR section 9.5.2 (page 9.5-12) describes a permanent system that is installed. The UFSAR also addresses a temporary system that may be used. In practice, the licensee only uses the temporary system. As a result, PC/M 95-131 was implemented to remove the permanent system. The inspector verified that the current UFSAR change package (scheduled for October 1996) will address this change. However, the UFSAR did not reflect the primary use of this temporary system since the 1980's (see section E8.2).

M1.10 Component Cooling Water Pressure Switch

WO 96004233 covered resetting the pressure controls for the Unit 4 Standby CCW Pump. As reported in LER 250/95-006, FPL determined by analysis that CCW heat exchangers were susceptible to damage due to vibration, if all components started as designed during an ESF actuation. It was determined that the low pressure automatic start signal for the CCW pumps had the potential to result in more than the desired number of pumps running should the pressure drop momentarily while the CCW configurations were being changed. Therefore, the setpoint for the low pressure auto-start was being lowered from 60 psig to 35 psig and the time delays between auto-start signals to successive pumps was being increased.

The inspectors observed portions of this work and verified compliance with the following associated documents: WO 96004233, including the Process Sheet, LER 250/95-006, Clearance No. 4-96-02-163, and UFSAR Section 9.3. The inspector concluded that this job was well planned and implemented. Personnel appeared to be well qualified for tasks being performed.

M1.11 Unit 4 Main Steam Flow Taps

WO95031971 covered modification of Unit 4 MS Flow Instrument Taps in accordance with PC/M 94-130. The applicable Code for welding involved with this PC/M was the ASME Boiler and Pressure Vessel Code, Section III, Subsection NC, 1980 Edition, W1980 Addenda.

The inspectors reviewed the PC/M, the completed Weld Process Sheets and radiographic film for the following welds:

Drawing Number	Weld Number
5614-P-559-S	FW-21 and FW-22
5614-P-560-S	FW-25 and FW-28
5614-P-561-S	FW-21 and FW-22

The completed Process Sheets were neat, complete, and provided detailed documentation for each weld. Review of the radiographic film revealed good weld quality technique, and good film quality.

M1.12 Component Cooling Water Test

Procedure 4-OSP-030.4 covered performance testing of the CCW Heat Exchangers to satisfy the surveillance requirements of Technical Specification Section 4.7.2.b.2. The inspectors observed taking the performance data, computer analysis of the data, and verification and trending of the results by the Engineer. These activities were observed/reviewed to verify compliance with Technical Specification 3/4.7.2, 4.7.3.b.2, and UFSAR Section 9.3.

The inspector concluded that the procedure was very detailed and was conscientiously followed by the data taker and the Engineer analyzing and evaluating the results.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Primary and Secondary Water and Steam Leaks

The inspector reviewed the licensee's program for identifying, tracking, and repairing steam and water leaks on primary and secondary piping systems. The licensee tracked the leaks with an open PWO and an identifying green tag in the field. Further, the daily POD package tracked the active leaks for each unit by location. Temporarily repaired leaks were additionally tracked by mechanical maintenance using a "Furmanite" listing with an open PWO. As of February 12, 1996, the following status was noted:

Unit	Furmanite Repairs		Active Leaks	
	Primary	Secondary	Primary	Secondary
3	0	11	2	10
4	0	15	13	11

The active leaks were either being repaired (permanent or temporary with Furmanite) or on a forced or refueling outage work list. All Furmanite repairs were scheduled for repair during the upcoming refueling outages or short notice outage of sufficient duration.

The inspector compared leak lists with those of several years ago, and noted a large improvement in the number of open items. The inspector concluded that aggressive management attention and improvements in the valve repacking programs have been effective.

M2.2 Unit 3 Steam Generator Feedwater Pump Discharge Check Valve Failure

On February 7, 1996, operators noted noise in the inlet (North) end of the Unit 3 6B high pressure feedwater heater. The feedwater heater was isolated, and maintenance began cutting the end bell for an inspection. Based on experiences from Unit 4 in 1993 (reference NRC Inspection Reports Nos. 50-250,251/93-22 and 24), the licensee suspected that one of the Unit 3 SGFP discharge check valve's disc pin and retaining screw may have come loose and found their way into the feedwater heater inlet.

The licensee performed acoustic monitoring of both SGFP check valves in an attempt to determine which check valve (3-20-118 or 3-20-218), and which hinge pin had become dislodged. Acoustic readings taken at 100% power, at 60% power, and with the 3A SGFP

off. These acoustic readings indicated the problem to be with the west hinge pin on the 3B SGFP check valve (3-20-218). Confirmation testing and the stopping of the 3B SGFP led to a Unit 3 reactor trip on February 9, 1996 (see section O4.1).

The licensee opened the 3B check valve and confirmed the west disc hinge pin and retaining screw were missing. These parts were subsequently located in the 6B feedwater heater and feedwater inlet piping. The licensee retrieved the parts and performed a damage assessment of the heater. Further, the check valve and the feedwater heater were repaired. The licensee concluded that the failure mechanism was similar to a 1993 Unit 4 failure, e.g., inadequate retaining screw tack welds. This permitted the screw to back out, causing the hinge pin to become dislodged. Modifications included increasing the size of the tack welds. The licensee subsequently inspected the 3A SGFP check valve internals. Although no problems were noted, maintenance modified the tack welds on both Unit 3 valves.

The inspector reviewed this issue including the 1993 Unit 4 occurrence. The inspector noted that no corrective actions addressed a possible Unit 3 problem. Condition Report Nos. 93-777 and 93-891 stated that the procedure (PMM), and related drawings should be changed to ensure adequate weld tack requirements. These corrective actions were verified to be complete. However, the licensee did take acoustic readings in 1993 which indicated that the Unit 3 valves internals were intact. However, no periodic monitoring was performed nor was any inspection performed during the two subsequent refueling outages (Spring 1994 and Fall 1995). This indicates a weakness in their corrective action program. A PWO (93026379) was initiated for valve 3-20-218; however, the PWO was canceled in September 1995. The basis for the cancellation was only one noted failure, a ten year inspection frequency for a check valve, and a second inspection on a Unit 4 valve did not note any problems. The inspector reviewed procedure O-ADM-701, Control of Plant Work Activities, section 5.4 PWO Cancellation. Although the check valve PWO was canceled per the ADM, the process may have inherent weaknesses.

The inspector reviewed the licensee's QA review of the reactor trip and related equipment issues (QRO 96-56). That report noted the generic implications of the check valve failure that occurred in 1993 was not appropriately addressed. Further, QA identified weaknesses in the corrective action program and in the licensee nonsafety related check valve program.

Overall, the inspector concluded although the SGFP check valves are not safety-related, weaknesses were identified relative to corrective actions and generic implications of the 1993 valve failure. Further, the PWO cancellation process should be reviewed as well as the licensee's check valve program. QA's review of the check valve issues was thorough and incisive.

M2.3 Unit 3 Rod Control Problems

The licensee restarted Unit 3 after the aquatic grass influx on February 16, 1996 (section O1.1). The reactor startup commenced at 11:50 a.m., on February 19, 1996, and criticality was achieved at 12:32 p.m. Subsequently, at 2:00 p.m., at about 1% power, the RCO stepped control bank D in one step and received an urgent failure alarm in the rod control system. I&C and operator inspection of the rod control cabinets determined a logic failure in power cabinet 1BD and a regulation failure in power cabinet 2BD. Operators entered procedure 3-ONOP-28, Reactor Control System Malfunction, and Technical Specification 3.1.3.1. The urgent failure alarm was successfully reset, and rods were exercised in and out. The technical specification action statement was exited. However, based on rod control concerns, the licensee conservatively shutdown Unit 3. Mode 3 was subsequently entered at 4:05 p.m.

I&C and technical personnel embarked on a troubleshooting plan per a GMI and procedure TP-96-21, Functional Checkout of the Unit 3 Rod Control System. The licensee identified multiple cards with problems and replaced them. This included cards in the 2BD power cabinet and logic cabinet cards associated with communications to the 1BD power cabinet. Troubleshooting and testing was completed and plant management authorized restart. The unit achieved criticality at 7:08 p.m., on February 20, 1996. Full power was reached at 6:25 p.m., on February 21, 1996.

The inspector reviewed licensee actions, including observation of control room startup and shutdown activities, ONOP and technical specification implementation, troubleshooting and testing activities at the rod control cabinets, and historical rod control problems. The licensee has had problems with the Unit 3 rod control power supplies (NRC Inspection Report 50-250,351/95-09), wetting of the 2BD power cabinet and unexplained 1BD urgent failure alarms (NRC Inspection Report 50-250,251/95-19). Further, Unit 3 recently completed a modification to upgrade the logic cabinet cards (NRC Inspection Report 50-250,251/95-16). The inspector questioned licensee personnel whether these mentioned issues could have caused or have been precursor events to these problems. Only the unexplained 1BD power cabinet urgent failure alarms could have been a precursor. The licensee did have a recorder monitoring the 1BD power cabinet for several months; however the problem never reappeared.

The inspector concluded that the licensee prudently shutdown Unit 3 to address these rod control problems. Further, testing and troubleshooting activities were well controlled and demonstrated strong teamwork among operations, maintenance, and technical department personnel. The inspector intends to follow additional

licensee efforts in this area, including root cause analysis for the card failures.

M2.4 Charging Pump Valve Failure

During a planned repacking of the 3C charging pump on February 22, 1996, the licensee identified that the south discharge valve had broken off. Though the valve had stayed in place, small metal slivers along the crack regions of the valve were missing and not found inside the block. The licensee initiated condition report 96-176 and an investigation. Further, the fuels group was also contacted to determine the potential and consequences on fuel damage from the metallic fragments. The fuels group conservatively estimated that the potential for fuel damage of up to eight pins existed. With eight failures, the INPO goal of RCS activity would be exceeded; however, the Technical Specification limit of 1.0 microCuries/gm would not be exceeded from these slivers. The licensee searched the pump block as well as the pulsation damper but were not able to locate the metallic fragments. The licensee postulated that the particles had a high probability for being retained either upstream of or by the discharge filters. However, radiological conditions prevented the licensee from searching the filters. The licensee plans to do a root cause analysis associated with the discharge valve failure.

The inspector reviewed and discussed the event with the licensee. When questioned the licensee informed the inspector that an awareness statement, such as a night order alerting the control room operators of the potential for fuel pin damage specifically as a result of the discharge valve failure, had not been issued. The inspector noted that the licensee periodically (daily or shiftly) sampled and plotted RCS activity levels. The inspector discussed this with the licensee. The licensee plans to look into this matter and determine the most appropriate method to heighten the awareness of the control room operator on this event. The inspectors concluded that the licensee was responsive to inspector comments. The inspector plans to followup this issue, including the planned root cause analysis expected to be completed in the near future.

M2.5 Unit 4 Crane Related Problems

On March 5, 1996 during required testing and preoperational checkouts, the Unit 4 polar crane was "Two Blocked". "Two Blocked" is when the main block of the crane comes in contact with the crane superstructure. The polar crane was not carrying any load at the time of the preoperational checkout. The polar crane does not provide a safety function; however, for seismic considerations, the plant considers the polar crane a Quality Related component. The licensee initiated a condition report (number 96-225) associated with this event. The polar crane was declared inoperable pending inspection, evaluation, and potential

repairs. With the polar crane unavailable, the Unit 4 refueling outage was impacted in that the capability to lift heavy loads was temporarily lost. This particularly delayed the vessel head detensioning and lift activities.

The licensee initiated an investigation, including coordination with the vendor. Further, the licensee determined that the upper limit stop switch did not function as required to prevent the crane block from moving past its required position. Further, deficiencies associated with current qualification associated with the involved maintenance personnel as well as deficiencies associated with the Reactor Polar Bridge Crane work description procedure (number 64/3676) were identified. These deficiencies included expired eye examination on one of the electricians and no instructions on what speed the main hoist should be operated during the checkouts. During checkout, the hoist was being operated at a faster speed that could have potentially contributed to the problem.

As corrective action, the licensee replaced the limit switch, conducted an extensive inspection, including coordination with the vendor, of the polar crane, and replaced the cable associated with the main hoist. Further, the licensee initiated action to rectify problems associated with the Reactor Polar Bridge Crane work description procedure. The licensee successfully returned the polar crane to service. To date, there have not been any additional problems attributable to the polar crane.

On March 13, 1996, during preparations prior to initiating core off-load in accordance with procedure 4-OP-038.4, Spent Fuel Pit Bridge Crane Operability Test Preparations for Refueling Activities, the SFP manipulator crane was inadvertently disabled. The south hoist load cell cable was tied off to the hand rails. Subsequently, when the SFP trolley was moved, the load cell cable snapped causing the manipulator crane to become unavailable. The north and south hoist associated with the manipulator crane have a common load cell in addition to individual load cells. Thus, with the south hoist load cell cable damaged, the functionality of the north hoist cable was also affected. The licensee initiated repairs to the damaged cable and in parallel initiated actions to develop a TSA such that the south hoist would be bypassed and core off-load could commence with the north hoist in service. However, the TSA was not implemented as the licensee completed repairs to the south hoist prior to initiating core off-load.

The inspector reviewed procedure 4-OP-038.4 and noted that the procedure had a caution step to tie the trolley cable to preclude it from being snagged. However, the non-licensed operator did not appropriately tie the cable to the trolley. The inspector concluded that the safety consequences of this and the polar crane "two blocking", were minimal. The inspector considered these two instances as a weakness in attention to detail.

M2.6 Unit 4 Steam Generator Level Control System Refurbishment

The inspectors reviewed licensee's plans, schedules, and implementation for refurbishment of the Unit 4 HAGAN Control Modules for SG level and feedwater controls. The scope included:

- A total of 72 Modules are included in the program.
- Eight per loop or 24 plus 10 switches will be refurbished for this outage.
- After the outage, lessons learned will be used to develop a schedule and method for the remaining 48. The process will be streamlined based on lessons learned.

A decision to replace certain components was made up-front. Parts with a known shelf life or parts known to age were replaced. In addition, some parts were replaced for standardization. All electrolytic capacitors, all pin jacks, certain relays, and certain boards were replaced. A detailed checklist was used to evaluate the condition of each module and determine which components, other than the ones identified up-front, need to be replaced. Work Orders were issued for each individual module specifying which parts are to be replaced. Work was accomplished in accordance with the WO and vendor's manual. The module was checked and calibrated in accordance with the vendor's manual and then calibrated for the application in accordance with site procedures. After installation, the module received an operability test. Essentially all of the modules needed for the Unit 4 Outage have been refurbished.

The inspectors reviewed/observed the following:

- The process was reviewed.
- Completed WO 95028337 for refurbishment of Isolator Assembly 4111083-001 (S/N Q0206) was reviewed.
- In-process refurbishment work was observed and the in-process WO (95028324) reviewed for Controller Assembly 4111080-004 (S/N 315).
- WO 95019866 covering testing of level controls after installation of refurbished modules was reviewed. In addition, the inspectors noted that a draft procedure for Main Feedwater Valve Control Loop Response Test, to be used after installation of the refurbished modules, was in the review and approval process.

Based on the above review, the inspectors concluded that this work was well planned and was being performed in accordance with written requirements.

M2.7 Unit 3 POV-3-4882 Failure

On March 11, 1996, during an OSP performance, valve POV-3-4882 failed to completely close. This valve isolates the B ICW header to the A TPCW header, including the basket strainer. Its function is to close and isolate the non-safety components (TPCW) from the safety components (ICW) during an SI signal. The licensee initiated condition report No. 96-304, declared the valve OOS, and reviewed Technical Specification entries.

The licensee performed an evaluation and calculation per PTN-3FJM-96-013, and concluded design basis flow was met. The licensee further concluded that no operability nor reportability issues existed. The licensee also evaluated the ability to backwash the other TPCW strainer (by closing POV-3-4883). The licensee's evaluation concluded that operator actions to close the manual valve within five minutes to isolate POV-3-4882 (with POV-3-4883 closed for backwash) was acceptable. The evolution was briefed and communication established. Repairs to POV-3-4882 were completed, and the A TPCW was returned to service. The licensee concluded that a lack of stem lubrication was the failure mechanism. Redundant components were either addressed or scheduled to be repaired.

The inspector reviewed the documentation and discussed this issue with licensee maintenance, engineering, licensing, and operations personnel. The inspector verified corrective actions. The inspector also reviewed UFSAR section 9.6, ICW, and verified that design description was appropriate (see section E8.2). The inspector concluded that the licensee appropriately addressed this issue.

M6 Maintenance Organization and Administration

M6.1 Scaffold and Painting Controls

During the period, the inspectors reviewed the licensee's preparations for the Unit 4 refueling outage. This pre-outage work included scaffold erection for maintenance, testing, a modification, and planned outage inspections. Early in the inspection period (e.g., early February), the inspectors noted a scaffold was being installed over and around safety-related components including the HHSI pumps, the containment spray pumps, the RHR system, and the pipe and valve room. The inspector questioned the necessity for erecting scaffolds in the vicinity of safety systems one month prior to outage. Licensee management had also noted this during routine inspections, and had initiated actions to remove certain scaffolds until the commencement of the outage.

Additionally at 2:00 p.m. on February 20, 1996, Unit 4 control room operators successfully responded to a feedwater transient on

the 4A S/G. Apparently, scaffold crews on the Unit 4 feedwater platform inadvertently hit an air bleed ball valve near SV-4-478B causing the valve to open, which then caused the feedwater regulating valve (FCV-4-478) to begin to close. The workers on the feedwater platform immediately recognized their mistake, closed the valve, and reported this information to the control room. Licensee corrective actions included initiation of condition report No. 96-162, logged the "near miss" event, plant management stopped all scaffold work, I&C inspected the air tubing with no problems noted, and a PWO was initiated to review the ball valve configuration (e.g., plugging the line or locking the valve).

Another event occurred on Unit 3 on February 26, 1996. Painters in the Unit 3 blowdown cage apparently bumped the feedwater flow lines, causing three different minor S/G level and flow transients. Operators successfully responded to these transients. (All occurred within 25 minutes.) The painting activity was stopped, condition report 96-187 was written, and an investigation and corrective actions were initiated.

The inspector concluded that weaknesses were noted relative to licensee's scaffold control program, control of painting activities and contractor control. Further, operators and scaffold personnel reacted quickly and effectively to prevent a Unit 4 trip on low S/G water level if the FCV would have closed fully on loss of air pressure. Likewise, operation response to the Unit 3 perturbations were also very good. Further, the inspector noted that QA has identified historical issues with scaffolds which licensee management is addressing.

M6.2 Auxiliary Feedwater Missed Surveillance

In response to NRC GL 96-01, Testing of Safety-Related Logic Circuits, the licensee identified a possible problem with a portion of the required surveillance testing of the AFW actuation logic. Technical Specifications Table 3.3.2 Item 6, requires instrumentation to actuate AFW on low-low S/G level, SI, bus stripping, or loss of SGFPs. In addition, AMSAC also starts AFW through different circuitry. Further, Technical Specification Table 4.3-2 Item 6a, requires surveillance of the actuation logic once per refueling to verify operability.

The licensee initiated condition report No. 96-163 at 6:45 p.m. on February 20, 1996, to document their initial findings. This action began a 3-day clock for engineering to complete their analysis, including an operability assessment. By the morning of February 22, 1996, the licensee had concluded that testing had not been accomplished. Procedures 3/4-OSP-075.4, Auxiliary Feedwater Auto-Start Test, apparently did not test all possible actuation logic paths. As a result, both units entered Technical Specification action 4.0.3 which required a missed surveillance to

be performed within 24 hours or the AFW would have to be declared inoperable. The entry was logged at 9:00 a.m. on February 22, 1996 for both units.

Engineering and technical department personnel developed an interim response to the condition report and a test procedure to verify the AFW logic. Procedure TP-96-023, Verification of 2 of 3 Low-Low Steam Generator Level Logic Matrix For Auxiliary Feedwater Start Circuit was developed. Later during the day on February 22, 1996, PNSC met and approved the condition report interim disposition and related safety evaluation (JPM-PTN-SENP-96-013) and procedure TP-96-023.

The test procedure was successfully performed on Unit 3 trains A and B AFW logic, and the unit exited the 24 hour action statement at 8:00 p.m. on February 22, 1996. Subsequently, the test procedure was successfully performed on Unit 4 trains A and B AFW logic, and the unit exited the 24 hour action statement at 10:15 p.m. on February 22, 1996.

The inspector reviewed the technical specifications, the TP, the condition report, related OSPs, the safety evaluation, GL 96-01, logic and electrical schematics of AFW actuation circuitry, and procedure O-ADM-217, Technical Specification Matrix. The inspector was briefed by engineering personnel on February 21 and 22, 1996, regarding this issue. The inspector also attended the PNSC meetings which reviewed this issue and discussed the item with operations, engineering, and plant management. The inspector also witnessed portions of the testing.

The AFW initiation logic includes a portion for S/G low level. A low level as sensed by two of three independent level instruments on any one of the three S/Gs, will actuate all three AFW pumps (e.g., both trains). The as-written OSP only verified one combination of the two of three coincident circuits for each S/G. However, the initiation relays which start the AFW pumps are common, and therefore were always tested. The inspector also noted that the AFW initiation signal is generated by the same RPS relays which actuate a reactor trip on any one S/G with a two of three coincidence low level. The only item not periodically tested was the effected relay contacts. The inspector independently verified that the TP adequately tested the remaining initiation circuitry. Longer term actions included a formal revision to the OSP initiation and submission of LER 96-04 on March 18, 1996, and completion of the GL 96-01 reviews.

Although prior opportunities existed to find this problem, and NRC directed the review of safety-related logic, the NRC considers this to be a licensee identified, non-cited violation of technical specification surveillance requirements. This was based on an aggressive and timely licensee review, minor significance as the AFW logic tested satisfactorily, the redundancy (e.g., multiple

AFW start signals) available, the fact that the monthly RPS test (each unit) did check the same relays (but not the contacts), and operators would start AFW if the auto start failed as directed per procedures 3/4-EOP-E-0, Reactor Trip or Safety Injection, Step 7.

In conclusion, formal enforcement action will not be taken. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. The item will be tracked as NCV 50-250,251/96-02-01, Failure to Meet AFW Surveillance Requirement. The NCV and the LER are considered closed.

M6.3 Overtime Usage

The inspector reviewed the licensee's followup to a concern (NSS-PTN-96-002) regarding possible maintenance supervision abuse of the overtime policy. This concern was that during the 1995 fall Unit 3 refueling outage, personnel exceeded the overtime rules. These rules state that an individual can work no more than 16 hours in a 24 hour period, or 24 hours in 48 hour period, or 72 hours in a week period. These rules do not include shift turnover time.

The licensee reviewed QA reports, security ingress/egress records, time sheets, and interviewed personnel. Further Technical Specification 6.2.2.f requirements, policy NP-306, and procedure QI-1-PTN-1 were also reviewed. The license concluded that no overtime violations occurred. However, individuals documented the use of between one half hour to two hours for shift turnover time, which was excluded from the overtime totals. Maintenance personnel stated that during the outage, one hour before and one hour after shift were necessary at times to effectively review work job status, e.g., turnover.

The inspector also reviewed the above documents, independently assessed overtime usage during the current Unit 4 1996 outage and previous outages. No violations were identified. The use of shift turnover time does not become accounted for in an individual's work hour totals. At times, a one half to one hour turnover time both before and after the work shift may be appropriate. This depends on work activities, work load, and oversight responsibilities.

The inspector concluded that the licensee appropriately followed up on this concern and that the concern was not substantiated. This issue was documented in a letter to the NRC (L-96-34) on February 21, 1996.

III. Engineering

Inspection Scope (37551, 90712, 90713, and 92700)

The inspectors verified that licensee engineering problems and incidents were properly reviewed and assessed for root cause determination and corrective actions. They accomplish this by ensuring that the licensee's processes included the identification, resolution, and prevention of problems and the evaluation of the self-assessment and control program.

The inspectors reviewed selected PC/Ms including the applicable safety evaluation, in field walkdowns, as-built drawings, associated procedure changes and training, modification testing, and changes to maintenance programs.

The inspectors also reviewed the report discussed below. The inspectors verified that reporting requirements had been met., root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. When applicable, the criteria of 10 CFR Part 2, Appendix C, were applied.

Inspection Findings

E1 Conduct of Engineering

E1.1 Unit 4 End-of-Cycle 15 Coastdown

The licensee approved a short duration coastdown for Unit 4 end-of-cycle number 15. The coastdown included a temperature coastdown of 5°F, followed by a reactor power coastdown. The coastdown was evaluated by safety evaluation JPN-PTN-SEFJ-96-002 dated February 9, 1996. The evaluation referenced a Westinghouse reload safety evaluation (Rev. 1) dated January 1996. Further, procedure 96-TP-018, Unit 4 Cycle XV T-Average and Power Coastdown, was written to implement the coastdown. PNSC approved all these referenced documents. The licensee began the temperature coastdown on February 25, 1996, and the power coastdown on February 28, 1996, and ended on March 1, 1996.

The inspector reviewed the referenced documents including training brief No. 602 and verified adequate implementation per the TP. The inspector noted that the licensee considered this evolution as infrequent and therefore applied special controls. Operators were briefed prior to the coastdown activities. The inspector interviewed selected operators, noting a good understanding of the process, tools, and TP. Overall, the Unit 4 coastdown was well planned and executed.

The inspector also reviewed the Technical Specifications and the UFSAR, and noted that coastdown was not addressed. The licensee's

10 CFR 50.59 safety evaluation appropriately addressed UFSAR accident analyses and the required areas, including determination that coastdown did not involve an unreviewed safety question nor a change to technical specifications.

E1.2 4A Residual Heat Removal Heat Exchanger Repair

On February 28, 1996, technical engineering personnel noted a small boric acid leak in the vicinity of a weep hole on the 4A RHR heat exchanger outlet nozzle reinforcement ring. Pressure testing confirmed a small leak. The licensee also initiated condition report No. 96-204 and an operability assessment. Engineering concluded that the 4A RHR was operable through the core offload window for Unit 4. (This time frame was about two weeks after the initial discovery.) Further, engineering concluded, based on calculations and a leak rate of several drops per minute (e.g., no visible leakage and only the formation of boric acid crystals), that the maximum crack size would be between 0.15 - 0.27 inches, with a limit of 0.94 inches to assure structural integrity. The RHR heat exchanger pipe is 10 inch schedule 40, and the area of the suspected leak was in the area of the nozzle to heat exchanger weld which provides greater structural strength.

After cavity floodup on March 12, 1996, the 4A RHR heat exchanger was removed from service for repairs. The repair method was to cut the attached piping, cut and remove the nozzle reinforcement ring and the nozzle. A new nozzle was welded to the heat exchanger shell and piping re-welded.

The inspector reviewed the condition report, operability assessment, and repair documentation packages. The inspector also attended meetings prior to and during repair and testing activities. The inspector noted the repair plan and implementation including radiological conditions and base estimates, FME controls, welding techniques, QA/QC coverage, engineering and maintenance oversight, NDE activities, remote monitoring by a camera/TV use, rigging controls, PMT and flushing, fire protection controls, root cause analysis and final documentation closeout.

Overall, the inspector concluded that the licensee appropriately dispositioned this issue, including operability assessment and repair activities.

E2 Engineering Support of Facilities and Equipment

E2.1 Auxiliary Feedwater Pump Issues

The inspector reviewed and discussed with the licensee circumstances surrounding "Terry" turbine driven AFW pump problems that have occurred recently at Turkey Point. The event date and nature of problems included the following:

February 9, 1996: The A AFW pump experienced an electronic and mechanical overspeed trip while reducing auxiliary feedwater flow during shutdown through closing of the AFW flow control valves. A time delay of approximately 2-3 seconds was identified between indication of the electronic overspeed and indication of the subsequent mechanical overspeed trip.. The governor valve stem was inspected and a band of corrosion external to the valve gland was noted. This corroded stem would interact with spacer rings and cause increased drag near the fully closed position. The stem travels approximately 7/8 inches from open to close position. It was concluded that the band of corrosion was caused due to the salt air environment that the AFW pumps are subjected to by virtue of being located in a non-enclosed area. The licensee replaced the stem and initiated a periodic drag test which involved hand stroking each governor valve. During this hand stroking, the governor valve linkages are connected and a push-pull meter is attached to measure the drag force required to stroke the valve. An acceptance criteria of 50 pounds was instituted. The governor is designed to overcome a force of 700 pounds.

February 16, 1996: The governor valve stem for the B AFW pump was noted to have increased drag during a the periodic drag test. The licensee replaced the stem. Upon inspection of the old stem, the licensee noted corrosion over its entire length, including the section within the governor valve gland. The licensee had addressed concerns identified in NRC Information Notice 94-66, Overspeed of Turbine-Driven Pumps Caused by Governor Valve Stem Binding, by performing a modification to the packing gland leakoff. However, the modification apparently did not precluded internal stem corrosion. As a conservative measure, the licensee also replaced the governor valve stem for the C AFW turbine.

February 23, 1996: During the weekly exercising of the A governor valve stem, the system engineer noted some looseness on the linkages that connect the governor to the governor valve. The vendor manual did not provide specific guidance on linkage adjustment. Consequently, the vendor was contacted to obtain recommendations for setting linkage clearances.

March 5, 1996: During testing of the A AFW pump following linkage adjustment due to the linkage looseness that was observed on February 23, 2996, the A AFW pump experienced an electronic overspeed trip at 5927 rpm. The electronic overspeed trip setpoint is 6200 rpm. The calibration of the overspeed trip module was found satisfactory. However, the output of the speed sensor was noted to be approximately 17 volt peak to peak instead of the desired 30-70 volt peak. Additionally, the sensor was found to be not firmly locked to the bearing cap and all the electrical conduit fittings were found to be loose. The sensor was removed and found to be bent and some wear on the tip was noted. The sensor was replaced and the gap adjusted to obtain the correct voltage output. The licensee postulated that the sensor

was stepped on during the recent maintenance activities. The licensee attributed this overspeed to the loose speed sensor.

March 7, 1996: During coastdown following completion of surveillance, the A AFW pump experienced an electrical overspeed trip. The licensee concluded that the overspeed trip was caused due to introduction of water from a dead leg into the steam supply as confirmed by movement of the steam inlet piping prior to and during the speed increase. The licensee is postulating that during coastdown, as the pressure in the steam supply line decreases, the water in the dead lag flashes to steam. This steam/water mixture enters the turbine and completely flashes to steam. In this process, there is sufficient energy to increase the turbine beyond the trip setpoint. Train 1 of the AFW system is susceptible to this problem and this issue was also discussed in NRC Inspection Report 96-01. An REA has been initiated to resolve this problem. The licensee performed an operability evaluation and concluded that the AFW susceptibility to trip on overspeed was limited to during coastdown conditions and that the starting capabilities were not affected. Further, the A AFW pump was rerun on March 7. During this run, the AFW started and shut down successfully without any problems. The inspectors observed the test and noted that both, during startup and shutdown, the turbine sentinel valve was passing moisture indicating moisture in the line. Further, a walkdown of the piping confirmed a lowpoint in the auxiliary steam to train 1 steam supply piping, which does not have any drain devices, (steam traps, orifices, etc). The inspector also reviewed applicable sections of the UFSAR and did not identify any discrepancies.

Pending replacement of the currently installed liquid nitride 410 stainless steel stems with Inconnel stems as well as completion of the modification associated with the train 1 steam supply line that is susceptible to accumulating condensate, the inspector is considering the issue open. This issue will be tracked as IFI 50-250,251/96-02-02, Auxiliary Feedwater Issues. The inspector also concluded that the licensee was responsive to inspector questions and that continued management attention pursuant to Auxiliary Feedwater issues is warranted.

E2.2 Turkey Point Unit 4 Cycle 16 Reload (PC/M No. 95-66)

The licensee initiated PC/M No. 95-66 for the Unit 4 Cycle 16 core reload. This PC/M provided for the reload core design and included the replacement of 60 irradiated assemblies with 60 new 15 x 15 optimized fuel assemblies. The new assemblies were of the debris resistant design which included several fuel design enhancements. These were similar to the recent Unit 3 reload designs.

The inspectors reviewed the documentation package for the PC/M including the design bases and analyses, the safety evaluation,

core loading plan, and other pertinent data. The inspectors noted that appropriate reviews and approvals were performed by Engineering, Reactor Engineering, QC, and the PNSC. The inspectors concluded that PC/M was well documented and adequately implemented by refueling procedures as discussed in section O1.3 of this report.

E2.3 Unit 4 Boron Injection Tank Modification (PC/M 95-172)

The licensee modified the Unit 4 HHSI system piping, such that the BIT was bypassed. During removal of the boric acid system (BAST) abandoned heat tracing/insulation, multiple through wall leaks were noted (see NRC Inspection Report Nos. 50-250,251/95-04, 06, and 09). These defects were caused by stress cracking corrosion and were all repaired. The licensee concluded that the BIT piping was also subject to this failure mechanism. Thus, the decision was made to bypass the BIT piping and abandon the BIT in place. The BIT function with highly concentrated boric acid was removed from service in the 1980's. The inspector verified this as described in the UFSAR section 6.2 and associated drawings (see section E8.2).

PC/M 95-172 removed the BIT instrumentation (PT, LC, PI, etc.) and relocated the RV-4-857. In addition, the inlet valves (MOV-3-867A and B) were eliminated and replaced by one manual valve (4-867). The MOV function had been previously removed. The SI function remained unchanged, included HHSI valves (MOV-4-843A and B), and associated controls, including the inter disc equalization function.

The inspector reviewed the PC/M package, including the 10 CFR 50.59 evaluation, and other related drawings and documentation. The inspector discussed the PC/M with engineering, operations, and maintenance personnel, including the system engineer. The inspector witnessed portions of PC/M in the field, including testing. Operator training was addressed through a training bulletin. The inspector concluded the PC/M was appropriately implemented.

E2.4 Emergency Load Sequencer Modification (PC/M No. 033)

The logic defect problems associated with the 3A, 3B, 4A, and 4B emergency load sequencers were discussed in NRC Inspection Reports 50-250,251/94-23, 95-01, 95-10, and 95-11, and in LERs 50-250,251/94-005-00 and 94-005-01. The licensee implemented PC/M 95-32 during the Unit 4 refueling outage to eliminate the root cause associated with the 4A and 4B sequencer defects previously discussed in NRC Inspection Reports and LERs. The sequencer software logic changes were developed using an enhanced verification and validation plan. The design changes implemented on the 4A and 4B sequencers included:

- deletion of the Auto Test Mode,

- logic changes to remove the test logic defects that manifested during manual testing,

- logic changes to ensure that a containment spray pump start in the event a high-high containment pressure signal was received just prior to the end of the third load block,

- enhancements to the elapsed time indicator to facilitate validation testing of the manual test mode,

- software enhancements to eliminate potential failure modes that would cause spurious actuation,

- load center 3H transfer logic changes to allow transfer of the load center while testing the EDG, with the load center breaker closed,

- modification to allow the sequencer to respond to valid scenarios during EDG testing,

- modification to sequencer startup transformer breaker open input signal to eliminate a potential sequencer failure mode that would be undetected until the startup transformer breaker is closed,

- local annunciator panel changes,

- sequencer front panel changes to remove the Auto Test Mode position,

- addition of a one second time delay to the manual test start pushbutton to ensure appropriate generation of sequencer error codes,

- removal of the high-high containment pressure input as a valid operational input which aborts the sequencer normal operational status to eliminate a possible nuisance alarm and error code during a valid event if the safety injection signal is reset by the plant operators prior to the high-high containment pressure signal being cleared,

- modification to the safety injection bus stripping pulse such that it would be prevented from occurring until after a 15 second LOOP timer has timed out to eliminate a potential overlap between a bus stripping trip signal and a first load block close signal for safety injection signal which occurs just prior to the start of LOOP sequencing,

- addition of a delay timer to the load center degraded voltage input logic to preclude generation of anomalous local alarm and control room alarm, and

- correction of drawing discrepancies identified during the sequencer verification and validation effort.

The licensee completed the modification, including testing, on 4A and 4B sequencers. The 4A and 4B sequencers were also challenged during the integrated safeguards testing. The 3A and 3B sequencers were modified during the September 1995 Unit 3 refueling outage.

The inspectors observed and discussed with the licensee portions of the modification and testing including the validation and verification that was performed on the spare sequencer in the training building. The inspector also reviewed applicable portions of the UFSAR.

The 4A and 4B sequencers were successfully challenged during the integrated safeguards testing. The inspector concluded that the PC/M was appropriately implemented.

E2.5 Unit 4 Main Steam Safety Valve Discharge Piping Replacement (PC/M No. 95-97)

In order to support the thermal uprate project, the licensee replaced the existing ten inch diameter discharge piping for each of the twelve MSSVs in Unit 4 with twelve inch diameter piping. The scope of the project was to replace approximately twenty-five feet of piping and modify two supports for each of the twelve MSSVs. In addition, permanent drains were provided for the discharge piping. The MSSVs serve to protect the secondary system from overpressurization. Four MSSVs are located on each of the three main steam lines, upstream of the MSIVs. PC/M 95-97 was completed during the Unit 4 Cycle 16 outage. A similar PC/M was completed on Unit 3 in 1995.

Based on analyses performed for the uprate condition, the licensee determined that the backpressure on the MSSVs resulting from the mass flow rate at uprate conditions coupled with the unusually long discharge lines would be excessive which could lead to high blowdown rates. High blowdown rates could result in RCS temperatures dropping below the "no-load" temperature, potentially affecting the fatigue analysis of several RCS components.

The licensee concluded that modifications provided by this PC/M did not have an adverse effect on plant safety, security or operation, did not constitute an unreviewed safety question and did not require changes to the technical specifications. Therefore, prior NRC approval for implementation was not required.

The inspector reviewed the PC/M package and related documentation, and observed installation on the Unit 4 steam platform. The inspector concluded that this PC/M was appropriately implemented and documented.

E2.6 Unit 4 Intake Cooling Water Modifications (PC/Ms-94-131 and 95-163)

The licensee abandoned the Unit 4 ICW to CCW heat exchangers outlet cooling valve (CV-4-2202) and the ICW to TPCW heat exchangers outlet valve (CV-4-2201) per PC/Ms 94-131 and 95-163, respectively. These valves have historically not functioned well and were previously bypassed per safety evaluations. Spool pieces were put in place of the CVs in parallel to a locked-open manual bypass valve. A similar PC/M was performed on Unit 3 last outage (September 1995). CCW system flow balancing is performed once per refueling outage by using throttling valves to all components. ICW system flow balancing was determined not to be necessary. This PC/M eliminated an operator workaround.

The inspector verified that UFSAR section 9.6 for the ICW system was being revised to reflect these PC/Ms. The inspector also reviewed the PC/M packages, procedure changes, safety evaluations, drawings, training briefs, and other related documentation. The PC/M was discussed with engineering and operations personnel. In addition, portions of the work were observed in the field.

The inspector concluded that the PC/Ms were appropriately implemented.

E2.7 Unit 4 Control Rod Current Order Timing Changes (PC/M No. 95-87)

As a result of a 1993 Salem Unit 2 event where the withdrawal of a single RCCA occurred when an insert signal command was given, the licensee implemented modification PC/M 95-87 on Unit 4. Unit 3 implemented for a similar a PC/M during the September 1995 refueling outage. These modifications were required by NRC Generic Letter 94-04, Rod Control System Failure, and Westinghouse Owner's Group program and technical bulletin NSD-TB-94-05-RO. These documents recommended performing a current order timing modification to the CRDMs and associated testing /surveillances that would prevent an asymmetrical rod withdrawal on a single failure.

The scope of the modification consisted of changing diode connections on each slave cycler decoder printed circuit board card located in the Rod Control System logic cabinet (12 cards plus 3 spares). Additional surveillances of the Rod Control System were implemented to detect single failures which do not affect rod motion, and therefore, were undetectable by routine rod insertion/withdrawal. Completion of the PC/M precluded adding an asymmetrical rod withdrawal event to Turkey Point's licensing

basis and performing the required Nuclear Fuel's analysis each reload.

During the current Unit 4 outage, PC/M 95-87 was completed. Post modification testing included performance of procedure TP-1197, CRDM Timing, Change Verification, and procedure 4-PMI-028.3, RPI Hot Calibration, CRDM Stepping Test, and Rod Drop Test. These tests uncovered several minor card errors which were corrected by the licensee.

The inspector reviewed the GL documentation, UFSAR Chapter 7.2, the PC/M and a post modification testing documentation, inspected the circuit cards in the field, and discussed the PC/M with the system engineer. Portions of the testing were also witnessed The inspector concluded that the licensee appropriately performed the PC/M.

E2.8 Unit 4 Containment Personnel and Escape Hatches Security Key Design Change (PC/M No. 94-097)

Based on inspector concerns raised in NRC Inspection Report No. 50-250,251/94-17 and on licensee concerns with the containment hatch interlock and locking devices, the licensee implemented PC/M 94-17 during the current refueling outage. The PC/M revised the key design to a quick release pin type for an improvement and ease of usage.

The inspector reviewed the PC/M package including the 10 CFR 50.59 review, drawings, change notices, process sheets, and other related documentation. The inspector also discussed implementation with engineering design and maintenance personnel, walked down the installation in the field, and concluded that the modification was satisfactorily implemented.

E2.9 Unit 4 Spare Control Rod Drive Mechanism Canopy Seal Clamps (PC/M No. 95-105)

Both Units 3 and 4 have experienced several leaks of the CRDM housings. The most recent occurred in March 1994, in the canopy seal weld of the Unit 4 G-9 spare CRDM housing (see NRC Inspection Report 50-250,251/94-05). These leaks have resulted in the affected unit being taken off line to perform repairs. To preclude forced outages associated with any future leaks on the Unit 4 spare penetrations, the licensee installed canopy seal clamp assemblies developed by ABB Combustion Engineering to create a new leak-tight boundary.

The spare CRDM itself serves no active safety function; however, it does provide a mechanical seal boundary. The assembly is designed to prevent separation of the clamp and loss of preload on the clamp seal under all service loadings. The canopy seal clamp does not impose any unacceptable stresses on the canopy seal of

the affected head penetration or in any way jeopardize the integrity of the existing pressure boundary. The assembly has adequate clearances when installed and doesn't adversely interact with other CRDM housings.

The assembly does not serve as part of the RCS pressure boundary even though it is mechanically attached to the CRDM housing. The assembly is designed to mechanically encapsulate the canopy seal area of the reactor vessel head nozzle penetration and functions as a backup to the non-structural canopy seal weld. The licensee performed this modification on Unit 3 per PC/M 95-26 during the September 1995 refueling outage. The inspector observed a training video tape associated with the remote device that was used to install the canopy seal clamps. The inspector also discussed the implementation with engineering personnel, and observed portions of the ongoing modification and concluded that the modification was satisfactorily implemented.

E2.10 Inspection, Repair, and Modification of the Unit 4 Intake Structure (PC/M No. 95-101)

As discussed in section 11.2.4 of NRC Inspection Report No. 50-250.251/94-07, the licensee's 1985 and 1986 inspections of the Unit 3 and 4 intake structure revealed corrosion and degradation of the circulating water pump thrust beams, horizontal struts, and deck support beams for the ICW pumps. As a result, the licensee implemented a long-term inspection, repair, and modification program for the intake structure. During the current Unit 4 outage inspection, the licensee identified corroded wall reinforcement bays in the 4A1 Intake Structure Well.

The inspectors examined the field work in progress, reviewed the completed PC/M documentation, and discussed the work with licensee personnel. The inspectors noted that a rebar associated with one of the intake bays had corroded. A condition report to evaluate and assess was initiated.

E2.11 Black Start Diesel Electrical Tie Elimination (PC/M No. 95-60)

The licensee implemented modification PC/M 95-60 to remove the electrical tie between the Black Start Diesels and the non-safety related 4KV C buses on both units. The power cable between 3C and 4C buses (i.e., breakers 3AC03/4AC03) remained as a cross-tie, with the breakers normally racked out. The Black Start Diesels' instruments and indications for Units 3 and 4 were removed from the control room panels. In addition, the breaker interlocks associated with the diesels were removed. The licensee also removed the 3C and 4C breaker interlocks in order to power any safety related A or B bus using a C bus transformer. In addition, the 3C/4C cross-tie used in conjunction with both units' existing tie to the safety related busses can now be used as a backup to the station blackout tie. These possible line-ups are not

provided for normal plant operation nor is any credit taken for their use for a design basis accident or station blackout condition. The existing inter-tie between the non-safety related C Busses and the safety-related train A or B Busses remains administratively controlled with all tie breakers normally racked out and locked and control fuses pulled.

The licensee previously received a licensing amendment for this change (Amendment 164/158) which allowed the B Standby Steam Generator Feedwater Pump electric driver motor to be replaced with a diesel engine driver and removed all licensing requirements for the Black Start Diesel Generators. This was reviewed in NRC Inspection Report No. 50-250,251/95-14.

During the current period, the inspector reviewed the completed PC/M 95-60 package and verified work completion in the field. The inspector also reviewed portions of the required procedure changes. Based on these reviews, the inspector concluded that the licensee appropriately implemented this modification.

E3 Engineering Procedures and Documentation

E3.1 Monthly Operating Report

The inspectors reviewed the January and February 1996 monthly operating reports and determined them to be complete and accurate.

E3.2 Licensee Event Reports

Four LERs were reviewed and closed during the period, including:

LER	REPORT SECTION
96-01	01.1
96-02	04.1
96-03	02.1
96-04	M6.2

The inspectors concluded that the LERs were appropriately written, timely, and met NRC requirements. Specific comments were discussed with licensing personnel. The inspector noted that LER 96-01 regarding canal grass issues was voluntary.

E8 Miscellaneous Engineering Issues

E8.1 Unit 3 and 4 Spent Fuel Pool

Core offload practices and spent fuel pool decay heat management during refueling outages was reviewed during NRC Inspection Report 50-250,251/95-19 and again during this period. Concerns in this area stem from a number of design and licensing problems discovered at the Millstone Unit 1 nuclear power plant in the fall

of 1995. The problems found at Millstone 1 triggered increased concern about whether all operating reactors were conducting refueling core offload activities in a manner that was consistent with the design assumptions described in the current licensing basis for the facility. A review of the current licensing and design bases as it pertains to spent fuel storage pool safety and refueling outage core offload practices was conducted by the inspectors and NRR. In addition, licensee operating practice was reviewed to determine consistency with these bases. The adequacy of the existing Turkey Point licensing basis will be addressed by NRR separately.

The SFP cooling loop consists of a pump, heat exchanger, filters, demineralizer, piping and associated valves and instrumentation. Component Cooling Water cools the SFP heat exchanger. CCW transfers the heat to the Intake Cooling Water system which circulates water from the cooling canals. Redundancy of the SFP equipment is not provided. The SFP loop is designed to remain functional during and following a seismic event and to structurally withstand a design temperature of 212°F. In the event of a failure of the SFP pump, a 100% capacity spare pump is permanently piped into the SFP cooling system. Another pump is available which is powered from a welding receptacle in the area. The transfer to spare pumps is done manually.

UFSAR 9.5 describes the refueling sequence of operation. This section stated that spent fuel is removed from the core and placed in the spent fuel pit while partially spent fuel is rearranged in the core. Other areas of the UFSAR also indicated that one third of the core is place in the spent fuel pool during refueling. However, actual practice at Turkey Point has been to conduct full core offloads. The licensee initiated CR 95-1138 on October 23, 1995, in response to NRC Region IV Morning Report of the same date regarding an error in the UFSAR regarding full core offload versus one third core offload. Various sections of the Turkey Point UFSAR were subsequently changed to reflect full core offload. However, the evaluation for this issue did not include a heat load analysis and portions of the UFSAR continued to reflect other than a full core offload. The licensee considered full core offload acceptable since previous full core offloads had been conducted and fuel pool temperatures remained below 140°F. NRR considers that prior full core offloads conducted at Turkey Point for normal refueling outages were not analyzed in the UFSAR.

The heat load analyses for the spent fuel pool is described in UFSAR section 14D which reflects analysis performed for the rerack amendment issued November 21, 1984. The SER associated with the amendment indicated that the expected maximum normal heat load following the last refueling will be 17.9 million BTU/hr resulting in a maximum temperature of 143°F. Also, a maximum abnormal heat load of 35.0 million BTU/hr results in a maximum bulk pool temperature of less than 183°F. Both of these heat load

calculations assumed moving fuel into the spent fuel pool 150 hours after shutdown. Procedure OP-038.1, page 13, approval date July 25, 1995, Preparation for Refueling Activities, however, specified a 100 hour delay between shutdown and start of fuel movement. This 100 hour time is specified in TS based on fuel handling accident analysis, however, the UFSAR delay time is more limiting. The inspectors verified that the licensee has never offloaded the core prior to 150 hours after shutdown due to the length of time it has taken to get to that point in the refueling. Procedure OP-38.1 was weak in that it did not specify the most limiting decay time (150 hours). The licensee corrected this procedure prior to offload.

The licensee had not conducted a heat load analysis for the case of a full core offload during refueling to ensure that the pool temperature would remain below the appropriate temperature limit, which the licensee considers to be 150°F. The licensee believed that the pool would remain below 140°F based on prior experience. Following questioning during this inspection period, the licensee agreed to perform a heat load analysis for the full core refueling offload and again revise the UFSAR under 10 CFR 50.59 to reflect the refueling full core offload practice prior to the offload. The heat load analysis indicated that a maximum spent fuel pool temperature of 147°F could be reached which was below the acceptance criteria of 150°F. This analysis was for this outage only and future full core offload must be addressed separately.

During the inspection period several procedures were revised to incorporate UFSAR requirements in this area. It did not appear, however, that procedural controls were in place to ensure the availability of the spare SFP pumps while the core is fully offloaded. The licensee appeared to rely on the conservatism of the personnel to ensure that the spare SFP pump would not be scheduled for work or otherwise be made unavailable during the core offload period. The inspectors consider that procedural controls may be necessary to ensure spare SFP pump availability during future full core offload conditions.

In summary, full core offloads conducted at Turkey Point for normal refueling outages were not analyzed in the UFSAR, Procedure OP-38.1 was weak in that it did not specify the most limiting decay time (150 hours), heat load analysis for future full core offload must be addressed, and procedural controls may be necessary to ensure spare SFP pump availability during future full core offload conditions. The adequacy of the existing Turkey Point licensing basis will be addressed by NRR separately.

E8.2 Review of the Turkey Point Updated Final Safety Analysis Report

10 CFR 50.71(e) requires the licensee to periodically update the UFSAR six months after each refueling. The licensee uses Unit 4 as the reference unit; therefore, the last UFSAR update was in May

1995. The next update is scheduled for October 1996. These UFSAR revisions are required to reflect all changes up to a maximum of six months prior to the date of filing the change (e.g., November 1994 for the May 1995 change).

UFSAR section 2.4.3, Transient Population did not reflect the Miami Air Show held at the Homestead Air Force Base in November 1994 and November 1995 (see report section P1.1). UFSAR sections 9.5 and 14D regarding the spent fuel pool, did not reflect nor analyze the practice of full core offloads. The UFSAR sections 9.5 and 11.1.2 does not reflect the primary use of temporary reactor cavity filtration systems nor temporary liquid radwaste processing systems, in place since the 1980's. Pending further NRC review, failure to update the UFSAR is an unresolved item and will be tracked as URI 50-250,251/96-02-03, Failure to Update UFSAR.

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameter to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters for the following.

UFSAR Chapter/Section	Report Section (s)
2C	O1.1
9.5	O1.3
7.2	O2.1, E2.7
5.2.3, 9.3.3, 14D, 5A, T11.2-5	M1.1
9.6	M2.7, E2.6
6.2	E2.3
10	M1.7
4.2, 4B, 4C	M1.8
3	M1.9

Based on recent industry experiences, the licensee performed a partial UFSAR self-assessment and audit. UFSAR chapters 3, 4, 6, 7, 8, 9, 11, 12, and 14, were reviewed by a five person team for two weeks in March 1996. The licensee noted 96 deficiencies; wrote a condition report (No. 96-404), and resolved all deficiencies. This included UFSAR changes for the next update (October 1996). Further, the licensee intends to audit the remaining chapters at a later time.

IV. Plant Support

Inspection Scope (71750)

The inspectors verified the licensee's appropriate implementation of the physical security plan; radiological controls; the fire protection program; the fitness-for-duty program; the chemistry programs; emergency preparedness; plant housekeeping/cleanliness conditions; and the radiological effluent, waste treatment, and environmental monitoring programs.

Inspection Findings

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Overflow of the A-Waste Monitoring Tank in Radwaste Building

On February 26, 1996 the WMT-A (A-Waste Monitoring Tank) located in the Radwaste building overflowed causing approximately 1900 gallons of water to be spilled in the radwaste building. The WMT-A contained processed water that had been sampled and approved for release as liquid effluent to the canal system. The radiological consequences of the spill were negligible and the spill was contained within the radwaste building. The licensee initiated a condition report number 96-192 and the Operations Supervisor conducted an investigation of the circumstances surrounding the event.

Turkey Point liquid waste disposal system includes three Waste Monitoring tanks located in the radwaste building and two Monitor tanks located in the auxiliary building. Liquid effluents, monitored by radiation monitor R-18, can be released through either of the five tanks. The task of operating the liquid waste disposal system, including valve manipulations and pump operations, is performed by non-licensed operators and is accomplished using procedure 0-OP-061.12, Waste Disposal System-Waste Monitor Tanks and Demineralizer Operation. Section 5.1 and referenced attachments of procedure 0-OP-061.12 delineate the method for placing the WMT in recirculation. The A-WMT recirculation flowpath included manually operated ball valve 1703, DIST DEMIN FILTER FROM WMT A, to be opened. Sections 5.1 and 6.1 and referenced attachments delineate the post recirculation alignment and the verification of appropriate log entries in the non-licensed operator logbook. The alignment following completion of recirculation requires valve 1703 to be closed. Section 5.3 and referenced attachments of procedure 0-OP-061.12 delineate the method for transferring contents of the WMT to a MT. Included in this is the requirement to notify the control room operator of the intent to transfer a WMT to a MT. Further, each step associated with procedure 0-OP-061.12 requires the performing operators initial. Following completion of each section of procedure 0-OP-61.12 the operator is required to note the Date/Time of

completion, print his name, and forward the completed copy to the NPS for review and signoff.

At approximately 11:45 a.m. on February 26, 1996 chemistry requested that the WMT-A be placed in recirculation prior to sampling. The liquid waste disposal system was aligned and recirculation initiated. Subsequently, following chemistry satisfactorily obtaining a sample, attachment 4 (Realigning WMT Pump A After Recirculation and Sampling) to procedure 0-OP-061.12 required valve 1703 to be closed. Later at approximately 2:00 p.m., chemistry requested that the contents of B WMT be transferred to the A MT as the B WMT was at 90 % level. The system was aligned and the transfer was initiated. At approximately 3:00 p.m., a chemistry contractor noticed a spill in the radwaste building and consequently notified the control room. The control room dispatched an operator to the radwaste building and the overflow was secured.

Upon investigation of the event, the licensee noted the valve 1703 had not been closed by the non-licensed operator as required by Attachment 4. Thus, during the transfer from the B WMT to the A MT a flow path from the discharge of the B WMT pump to the A WMT via valve 1703 was created. With the A WMT already full, the additional flow caused the A WMT to overflow. The licensee could not locate the completed copy of procedure 0-OP-061.12, section 5.1 that was used to recirculate the A WMT. The non-licensed operator stated that he had completed the copy and routed it to the control room. Further, the licensee noted that the control room was not notified and that appropriate entries were not made in the non-licensed operator logbook as required by procedure 0-OP-061.12. However, steps in 0-OP-061.12 indicating that the control room notifications and log entries were completed.

The inspector reviewed the applicable procedures including radiological surveys (before and after the spill), UFSAR sections, discussed the event with the licensee, and performed a walkdown of applicable portions of the liquid waste disposal system. UFSAR section 11.1.2 describes certain radwaste systems which have been abandoned since the 1980's (see section E8.2). The inspector concluded that the existing procedure was adequate to appropriately perform the liquid waste water movement evolution. Further, the inspector concluded that licensee investigation and actions pertaining to this event were strong. The inspector determined that the failure to follow requirements of 0-OP-061.12, Waste Disposal System-Waste Monitor Tanks and Demineralizer Operation is unresolved URI 50-250,251/96-02-04, Radwaste Building Spill, pending further NRC review.

R1.2 Unit 4 Containment Inspections

Periodically during the Unit 4 outage, the inspectors made containment entries to review work in progress, radiological

conditions, and annual housekeeping and general material conditions.

R1.3 Radiation Controls During the Unit 4 Outage

The inspectors reviewed the licensee's radiological controls to minimize dose to prevent contamination spread, and to protect workers during the Unit 4 refueling outage. The inspectors noted good practices included remote monitoring by the use of cameras. CCTVs, and dose telemetry. Observed jobs included RPV and cavity work, CRDM clamp installations, S/G primary work, 4A RHR heat exchanger repair, and other containment work. Overall dose performance will be reviewed in a subsequent inspection.

R1.4 Unit 4 Spent Fuel Pool Transfer Canal High Radiation

On March 15, 1996, during core alterations, HP personnel noted higher than expected radiation levels on the Unit 4 auxiliary building roof in the vicinity of the SFP transfer canal outer wall. An HP technician was in the area when the assigned alarming dosimeter alarmed on dose rate (e.g. 80 mrem/hr). The individual contacted the HPSS, and the high dose rates were confirmed. A condition report (No. 96-363) was written and the HP personnel confirmed that the high dose rates were caused by spent fuel being transferred from the SFP upender (through the transfer canal) to the SFP storage racks.

Subsequent fuel moves were monitored by HP, posted as high radiation areas and locked high radiation areas. Dose rates observed were as high as 1500 mrem/hr on contact with the concrete wall and 900 mrem/hr at 12 inches. The effected area was about 30 feet long and 15 feet high, and corresponded to an irradiated fuel bundle traversing the SFP transfer canal.

The inspector reviewed the condition report, surveys, UFSAR and discussed the issue with HP and operations management. The inspector noted a good questioning attitude by the HP technician and the HPSS who uncovered this problem. Pending completion of the licensee's investigation, including root cause and corrective actions, and NRC specialist review this issue is unresolved. The issue will be tracked as URI 50-250,251/96-02-05, SFP Transfer Canal High Radiation.

R3 RP&C Procedures and Documentation

R3.1 Employee Terminations

The inspector reviewed the licensee's process for performing personnel separations either due to layoffs or unsatisfactory work performance. A "Notice of Separation" checklist was used by the supervisor to document the individual's checkout process. Included in this checkout were items Number 15 (Speakout

interview) and Number 16 (whole body count). The Speakout organization handles the employee concerns program. Further, administrative procedure O-ADM-600, Radiation Protection Manual, section 5.5.2.3.b stated that a whole body count should be performed for terminated employees. The ADM further stated that if a person leaves without receiving a radiological whole body count, a documented investigation should be performed for the potential of receiving an intake. Furthermore, if a Speakout interview was not held either due to the employee's or Speakout's unavailability, or due to the employee's desire not to go to Speakout, then a registered letter is generally mailed to the employee. This letter requests the former employee to contact Speakout by mail (stamped envelope included) or telephone (toll free number) with any concerns. Also, for a missed whole body count, a letter is also sent to the employee along with the individual's NRC Form 5 (dose records) and a copy of the intake investigation results.

The inspector reviewed the records for terminated employees from November 1, 1995, to March 6, 1996. This included the reduction-in-force layoffs as discussed in NRC Inspection Report No. 50-250,251/95-19. Of 64 FP&L personnel that were terminated, 13 did not go to Speakout and seven did not receive a whole body count. In each case, letters were sent or were planned to be sent to all effected individuals. This was verified by record review.

In conclusion, the inspector noted that some individuals did not receive Speakout interviews nor whole body counts. However, licensee procedures addressed this possibility. Additionally, a review of the requirements of 10 CFR 20.1502 was performed. No violations or deviations of NRC requirements were identified.

R3.2 1988 Spent Fuel Pool Spill Event

The inspector reviewed the licensee's followup to a concern (NSS-PTN-95-001 regarding a security contractor that claimed contamination from a Unit 4 SFP spill on August 16, 1988. Reviewed documentation included ERT report No. 88-15, radiological event reports, dose records, and related correspondence. The licensee concluded that 19 personnel received contaminations (14 clothing and five skin). One individual received a whole body count, and results were negative. Also, as evidenced by record review, the individual (security contractor) did not receive exposure for the period, was not contaminated, and an exit whole body count was negative.

The inspector also reviewed NRC Inspection Report No. 50-250,251/88-25 which reviewed this event. No radiological related violations were identified. The inspector concluded that the licensee appropriately followed up on this concern, and that the concern was not substantiated. This was documented in a letter to the NRC (L-96-34) on February 21, 1996.

R4 Staff Knowledge and Performance in RP&C

R4.1 Contaminated Material Controls

On March 15, 1996, a worker noted a purple colored nitrogen bottle in the Unit 3 main steam platform cage on the turbine deck. Generally, purple signifies potential contamination present. The worker notified operations and HP. HP performed a survey and found 280,000 dpm fixed contamination levels. Condition report No. 96-362 was written and the bottle was removed from the main steam cage and placed into the RCA.

The nitrogen bottles are filled from a facility within the RCA and then transported outside the RCA for use. A check of bottles found one other "purple" colored bottle within the nitrogen gas filling facility. Neither bottle was tagged as radioactive. The licensee believes that HP personnel failed to survey the bottle when it left the RCA. The licensee did note that the "purple" markings were faint and difficult to detect.

The licensee informed the inspector of this incident, including root cause and corrective actions. The inspector noted that the event was documented in the RCO and HPSS log books. The inspector examined the bottle and confirmed the faint purple markings. The inspector reviewed the condition report, and corrective actions included tagging the affected bottles, requiring surveys of all bottles within the RCA and only ones that are transported, stressing survey and material marking requirements to HP personnel, and improving the purple markings. The inspector confirmed these actions and discussed the event with HP and plant management personnel.

The inspector concluded that failure to adequately survey items when leaving the RCA to ensure that radioactive material does not leave the RCA, was a violation of licensee procedures and NRC regulations. The inspector also noted that the issue was taken seriously by licensee management and corrective actions were prompt and aggressive. Further, the identification of the condition by a utility worker was indication of a questioning attitude. The inspector also concluded that the safety significance was minor because the bottle was adequately shielded while in the cage and no personnel received any unwarranted exposure from this unmarked and unposted radioactive material. The licensee identified violation will not be subject to enforcement action because the licensee identified the issue and because licensee corrective actions were prompt and appropriate. This meets the criteria specified in Section VII.B of the NRC Enforcement Policy. This item is being tracked as NCV 50-250,251-96-02-06, Failure to Adequately Survey Material Leaving the RCA. This item is closed.

P1 Conduct of EP Activities

P1.1 Emergency Plan Evacuation and Access Routes

During the week of March 4, 1996, brush fires occurred south and southwest of the site, approximately 8-10 miles away. The fires were in the vicinity of U. S. Route 1 and Card Sound Road. Extremely dry conditions and high winds resulted in the fires spreading, and hampered their extinguishment.

As discussed in the EP Plan section 5 and Figure 5-2, two evacuation routes are described: The normal is Palm Drive, and the alternate is through the cooling canal system (via Levee 31 Access Road) to Card Sound Road.

The inspector independently verified that neither evacuation route was effected. Verifications were based on map reviews, inspections in field, and through discussions with the licensee.

In addition, the inspector reviewed the licensee's interface with the local Homestead Motorsports Complex (see NRC Inspection Report 50-250,251/95-19). Two additional auto races occurred during this period. Further, the inspector reviewed the UFSAR section 2.4 again regarding transient population within the EPZ . Although the current UFSAR does not address the Homestead motorsports complex nor the Homestead Air Force Base Miami Air Show transient populations, the licensee's next revision will address it (see section E8.2).

S2 Status of Security Facilities and Equipment

S2.1 Vehicle Barrier System

The inspector reviewed the licensee's implementation of 10 CFR 73.55 section (c) (7) relative to a vehicle barrier system. Regulations required implementation by February 29, 1996. The inspector walked down the system with security management and noted implementation prior to the deadline. Final NRC review and acceptance will be performed by security specialists and documented in a future inspection. The inspector concluded that licensee security personnel were knowledgeable of their systems.

V. Management Meetings

XI. Exit Meeting Summary

The inspection scope and findings were summarized during management interviews held throughout the reporting period with both the site vice president and plant general manager and selected members of their staff. An exit meeting was conducted on March 29, 1996. (Refer to section 1.0 for exit meeting attendees.) The areas requiring management attention were reviewed. The inspector described the areas inspected and

discussed in detail the inspection results. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Partial List of Persons Contacted

* T. V. Abbatiello, Site Quality Manager
R. J. Acosta, Company Nuclear Review Board Chairman
J. C. Balaguero, Reactor Engineering Supervisor
P. M. Banaszak, Electrical/I&C Engine Supervisor
C. R. Bible, Site Engineering Manager
W. H. Bohlke, Vice President, Engineering and Licensing
T. J. Carter, Project Engineer
J. M. Donis, BOP Engineer Supervisor
R. J. Earl, QC Supervisor
S. M. Franzone, Instrumentation and Controls Maintenance Supervisor
R. J. Gianfrancesco. Maintenance Planning Supervisor
* R. G. Heisterman, Maintenance Manager
J. R. Hartzog, Business Systems Manager
* P. C. Higgins, Outage Manager
* G. E. Hollinger, Licensing Manager
* R. J. Hovey, Site Vice-President.
M. P. Huba, Procurement Supervisor
* D. E. Jernigan, Plant General Manager
H. H. Johnson, Operations Manager
M. D. Jurmain, Electrical Maintenance Supervisor
* V. A. Kaminskas, Services Manager
J. E. Kirkpatrick, Fire Protection, EP, Safety Supervisor
* J. E. Knorr, Regulatory Compliance Analyst
G. D. Kuhn, Procurement Engineering Supervisor
M. L. Lacal, Training Manager
J. D. Lindsay, Health Physics Supervisor
* J. T. Luke, Engineering (new)
E. Lyons, NSSS Engineer Supervisor
* F. E. Marcussen, Security Supervisor
R. B. Marshall, Human Resources Manager
D. D. Miller, Acting Projects Supervisor
C. L. Mowrey, Compliance Specialist
H. N. Paduano, Manager, Licensing and Special Projects
M. O. Pearce, Projects Supervisor
K. W. Petersen, Site Superintendent
T. F. Plunkett, President, Nuclear Division
K. L. Remington, System Performance Supervisor
R. E. Rose, Nuclear Materials Manager
C. V. Rossi, QA and Assessments Supervisor
D. Sager, Vice President, Nuclear Assurance
A. M. Singer, Operations Supervisor
R. N. Steinke, Chemistry Supervisor
E. A. Thompson, Project Engineer
D. J. Tomaszewski, Component Specialist Supervisor

B. C. Waldrep, Mechanical Maintenance Supervisor
G. A. Warriner, Quality Surveillance Supervisor

Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, mechanics, and electricians.

NRC Resident Inspectors

* B. B. Desai, Resident Inspector
* T. P. Johnson, Senior Resident Inspector

* Attended exit interview

Partial List of Opened, Closed, and Discussed Items

Item Number	Status, Description, and Reference
50-250,251/96-02-01	(Closed) NCV, Failure to Meet AFW Surveillance (section M6.2)
50-250,251/96-02-02	(Open) IFI, Auxiliary Feedwater Issues (section E2.1)
50-250,251/96-02-03	(Open) URI, Failure to update the UFSAR (section E8.2)
50-250,251/96-02-04	(Open) URI, Radwaste Building Spill (section R1.1)
50-250,351/96-02-05	(Open) URI, SFP Transfer Canal High Radiation (section R1.4)
50-250,251/96-02-06	(Closed) NCV, Failure to Survey Material Leaving the RCA (section R4.1)

Additionally, the following previous items were discussed:

Item Number	Status, Description, and Reference
LER 50-250/96-01	(Closed) ICW Low Flows Due Intake Grassing (section O1.1)
LER 50-250/96-02	(Closed) Unit 3 Reactor Trip (section O4.1)
LER 50-250/96-03	(Closed) Unit 3 Technical Specification 3.0.3 entry due to Rod Positions (section O2.1)
LER 50-250/96-04	(Closed) Missed AFW Surveillance (section M6.2)

List of Acronyms and Abbreviation

AC	Alternating Current
ADM	Administrative (Procedure)
AFW	Auxiliary Feedwater
a.m.	Ante Meridiem
amp	Ampere
AMSAC	ATWS Mitigation System Actuation Circuitry
ANPS	Assistant Nuclear Plant Supervisor
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BAST	Boric Acid Storage Tank
BIT	Boron Injection Tank
BOP	Balance of Plant
BTU	British Thermal Unit
CCTV	Closed Circuit Television
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CHECKMATE	FAC related computer prediction programs
CRDM	Control Rod Drive Mechanism
Cr	Chromium
CSI	Component Specialty and Inspection
CTRAC	Commitment Tracking
CV	Control Valve
DC	Direct Current
D. C.	District of Columbia
DP	Differential Pressure
dpm	Disintegrations Per Minute
DPR	Power Reactor License
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
e.g.	For Example
EOP	Emergency Operating Procedure
EP	Emergency Preparedness
EPRI	Electrical Power Research Institute
EPZ	Emergency Planning Zone
ERT	Event Response Team
ESF	Engineered Safeguards Feature
FAC	Flow Accelerated Corrosion
FCV	Flow Control Valve
FL	Florida
FME	Foreign Material Exclusion
FPL	Florida Power and Light
FW	Feedwater
GL	Generic Letter
GMI	General Maintenance - I&C
GMM	General Maintenance - Mechanical
GOP	General Operating Procedure
gpm	Gallons Per Minute
HHSI	High Head Safety Injection
HP	Health Physics
HPES	Human Performance Evaluation System

HPSS	HP Shift Supervisor
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IFI	Inspector Followup Item
INPO	Institute for Nuclear Power Operations
IRPI	Individual Rod Position Indication
IST	Inservice Test
JPM	Job Performance Measurement
JPN	Juno Project Nuclear (Nuclear Engineering)
KV	Kilovolt
L	Letter
LC	Level Controller
LER	Licensee Event Report
LI	Level Indicator
LLRT	Local Leak Rate Test
LOOP	Loss of Off-Site Power
LPDR	Local PDR
Mo	Molybdenum
MOV	Motor-Operated Valve
MOVATS	MOV Acceptance Testing System
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSR	Moisture Separator Reheater
MSSV	Main Steam Safety Valve
MT	Monitor Tank
N	Neutron Monitoring
NCV	Non-Cited Violation
NDE	Non-destructive examination
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSD	Nuclear Safety Division (Westinghouse)
NSS	Nuclear Safety (Speakout)
ONOP	Off-Normal Operating Procedure
OOS	Out-of-Service
OP	Operating Procedure
OSP	Operations Surveillance Procedure
OTSC	On-the-Spot Change
P	Permissive
PC/M	Plant Change/Modification
PCV	Pressure Control Valve
PDR	Public Document Room
PI	Pressure Indicator
p.m.	Post Meridiem
PM	Proactive Maintenance
PMAI	Plant Manager Action Item
PMM	Preventive Maintenance - Mechanical
PMT	Post-Maintenance Test
PNSC	Plant Nuclear Safety Committee
POD	Plan-of-the-day
POV	Power Operated Valve
PORV	Power-Operated Relief Valve

PT	Liquid Penetrant (inspection)
PT	Pressure Transmitter
PTN	Project Turkey Nuclear
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
QR	Quality Report
RCA	Radiation Control Area
RCCA	Rod Control Cluster Assembly
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REA	Request for Engineering Assistance
RHR	Residual Heat Removal
rpm	Revolutions Per Minute
RPI	Rod Position Indicator
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RTV	Room Temperature Vulcanizing (Silicone Rubber)
SEFJ	Safety Evaluation Fuels - Juno
SEMS	Safety Evaluation Mechanical - Site
SENP	Safety Evaluation Nuclear Plant
SER	Safety Evaluation Report
SFP	Spent Fuel Pit
S/G	Steam Generator
SI	Safety Injection
SGFP	S/G Feedwater Pump
SRO	Senior Reactor Operator
SV	Solenoid-Operated Valve
T	Temperature
TB	Test Bulletin or Technical Bulletin
TCN	Temporary Change Notice
TP	Temporary Procedure
TPCW	Turbine Plant Cooling Water
TS	Technical Specification
TSA	Temporary System Alteration
UFSAR	Updated Final Safety Analysis Report
U. S.	United States
U. S. C.	U. S. Code
URI	Unresolved Item
V	Volt
VIO	Violation
WMT	Waste Monitoring Tank
WO	Work Order