UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-250/95-06 and 50-251/95-06

Licensee: Florida Power and Light Company
9250 West Flagler Street
Miami, FL 33102

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

Facility Name: Turkey Point Units 3 and 4

Inspection Conducted: February 26 through March 25, 1995

Inspectors: T. P. Johnson, Senior Resident Inspector — 4/5/95 Date Signed

Accompanying Inspectors: B. B. Desai, Resident Inspector
L. Trocine, Resident Inspector

Accompanied by: J. F. King, Intern, Office of Nuclear Reactor Regulation

Approved by: K. D. Landis, Chief, Reactor Projects Section 2B, Division of Reactor Projects — 4/6/95 Date Signed

SUMMARY

Scope:

This resident inspection was performed to assure public health and safety, and it involved direct inspection at the site in the following areas: plant operations including 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.

Results:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations. The inspectors had the following findings:

Non-Cited Violation 50-250,251/95-06-01, Missed Operator Round; Failure to Follow Operations Surveillance (section 4.2.5)

Non-Cited Violation 50-250,251/95-06-02, Inadequate Definition of Reactor Coolant Loops Filled; Failure to Meet Technical Specification 3.4.1.3.1 (section 4.2.3)

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

Plant Operations

The inspectors noted instances of component labelling and drawing deficiencies (section 4.2.1). The licensee conservatively shut down and cooled down Unit 4 to perform valve maintenance. The shutdown and restart activities were conducted in a professional manner, and management involvement and interdepartmental teamwork were evident (section 4.2.2). A licensee-identified technical specification violation of the requirements for the reactor coolant system loops being filled during Mode 5 was a non-cited violation (section 4.2.3). Operations personnel were knowledgeable of technical specification and procedural requirements and handled a conservative Unit 3 load reduction as a result of an unexpected influx of aquatic algae and grass in the intake structure in a professional manner. Licensee management personnel were involved, and interdepartmental teamwork was a strength (section 4.2.4). A previous unresolved item regarding a missed non-licensed operator round was determined to be a non-cited violation (section 4.2.5).

Maintenance

Inspector-observed station maintenance and surveillance testing activities were completed in a satisfactory manner (sections 5.2.1 and 5.2.2). Good procedure compliance, strong oversight by quality assurance and operations management, and system engineer and maintenance personnel involvement were noted during emergency diesel generator and turbine testing (sections 5.2.3 and 5.2.6). Maintenance and operations personnel appropriately responded to an unexpected closure of an intake cooling water valve (section 5.2.4). The licensee effected boric acid system repairs in a deliberate and conservative manner (section 5.2.5). Unit 3 turbine front standard testing and maintenance was well planned and implemented, with strong oversight (section 5.2.6).

Engineering

An auxiliary oil pump failure was appropriately reviewed by an event response team (section 6.2.1). The residual heat removal sump recirculation suction valves have their downstream discs drilled to prevent pressure binding; however current licensee documentation did not reflect this (section 6.2.2). The licensee identified a potential condition with circuit breakers. This item was appropriately reported, reviewed, and analyzed for operability (section 6.2.3). The licensee responded to a 10 CFR Part 21 notification regarding recorders in a timely manner (section 6.2.4). The licensee's engineering efforts in evaluating the failure of a letdown orifice isolation valve were

aggressive and comprehensive (section 6.2.5). A licensee/Nuclear Regulatory Commission engineering meeting was beneficial in understanding engineering issues (section 6.2.6). The licensee aggressively pursued an issue regarding Rosemount transmitters. The licensee determined that Turkey Point does not have installed in the plant any of the Rosemount pressure transmitters that have the Monel sensor isolation diaphragms instead of the required stainless steel material (section 6.2.7). The licensee's efforts in evaluating and repairing a body-to-bonnet leak on a Unit 4 pressurizer spray valve were aggressive and comprehensive (section 6.2.8). An open item regarding containment isolation valves was closed (section 6.2.9). The monthly operating report was appropriate (section 6.2.10).

Plant Support

Inspector periodic containment tours during the Unit 4 forced outage noted good radiological controls and housekeeping (section 7.2.1). The licensee appropriately reported and responded to slight radioactive contamination of canal algae material (section 7.2.2). Emergency preparedness exercises were effective in providing training for emergency response personnel (section 7.2.3). The licensee appropriately responded to and reported a fatal car accident on the access road within the owner controlled area (section 7.2.4).

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REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

* T. V. Abbatiello, Site Quality Manager
R. J. Acosta, Company Nuclear Review Board Chairman
J. C. Balaguero, Technical Department Supervisor
* W. H. Bohlke, Vice President, Engineering and Licensing
M. J. Bowskill, Reactor Engineering Supervisor
S. M. Franzone, Instrumentation and Controls Maintenance Supervisor
J. E. Geiger, Vice President, Nuclear Assurance
R. J. Gianfrancesco, Maintenance Support Services Supervisor
J. H. Goldberg, President, Nuclear Division
* R. G. Heisterman, Maintenance Manager
* P. C. Higgins, Outage Manager
* G. E. Hollinger, Training Manager
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/Safety Supervisor
J. E. Knorr, Regulatory Compliance Analyst
* R. S. Kundalkar, Engineering Manager
J. D. Lindsay, Health Physics Supervisor
F. E. Marcussen, Security Supervisor
* C. L. Mowrey, Licensing Assistant
H. N. Paduano, Manager, Licensing and Special Projects
M. O. Pearce, Projects Supervisor
* T. F. Plunkett, Site Vice President
D. R. Powell, Technical Manager
* R. E. Rose, Nuclear Materials Manager
* D. J. Tomaszewski, Acting Technical Manager
A. M. Singer, Operations Supervisor
R. N. Steinke, Chemistry Supervisor
B. C. Waldrep, Mechanical Maintenance Supervisor
* E. J. Weinkam, Licensing Manager

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

1.2 NRC Resident Inspectors

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

1.3 Other NRC Personnel on Site

K. P. Barr, Chief, Emergency Preparedness Section, Radiological Protection and Emergency Preparedness Branch, Division of Radiation Safety and Safeguards, Region II
R. P. Croteau, Project Manager, Project Directorate II-2, Division of Reactor Projects I/II, Office of Nuclear Reactor Regulation
T. Decker, Chief, Radiological Effluents and Chemistry Section, Radiological Protection and Emergency Preparedness Branch, Division of Radiation Safety and Safeguards, Region II
* J. F. King, Intern, Office of Nuclear Reactor Regulation
T. A. Peebles, Chief, Operations Branch, Division of Reactor Safety, Region II
S. Sandin, Headquarters Operations Officer, Incident Response Branch, Division of Operational Assessment, Office of Analysis and Evaluation of Operational Data

* Attended exit interview (Refer to section 8.0 for additional information.)

Note: An alphabetical tabulation of acronyms used in this report is listed in section 9.0 of this report.

2.0 Other NRC Inspections Performed During This Period

Report No.	Dates	Area Inspected
50-250,251/95-300 (Partial)	February 27 - March 3, 1995	Licensed Operator Exams
50-250,251/95-05	March 6-10, 1995	Radiological Effluents and Chemistry, Radwaste Shipping, and Transportation
50-250,251/95-07	March 20-24, 1995	Annual Emergency Plan Exercise
50-250,251/95-08	March 20-24, 1995	Service Water Self-Assessment

NOTE: The initial portion of NRC inspection No. 50-250,251/95-300 was conducted during the previous resident inspector reporting period.

3.0 Plant Status

3.1 Unit 3

At the beginning of this reporting period, Unit 3 was operating at or near full power and had been on line since December 29, 1994. Reactor power was reduced to 60% power on March 8, 1995, as a precaution due to canal water algae intrusion into the intake structure. The unit was returned to full power on March 10, 1995. (Refer to section 4.2.4 for additional information.)

3.2 Unit 4

At the beginning of this reporting period, Unit 4 was operating at or near 100% reactor power and had been on line since December 2, 1994. Reactor power was reduced to 40% power to perform testing and maintenance on March 3, 1995. On March 6, 1995, while the unit was at 60% power during the power escalation, Unit 4 was shut down to Mode 3 to repair a letdown valve. Subsequently, an observed body-to-bonnet leak on a pressurizer spray valve caused the unit to proceed to Mode 5. The unit was returned to service and rated power was achieved on March 12, 1995. (Refer to sections 4.2.2, 6.2.5, and 6.2.8 for additional information.)

3.3 Common

On March 21, 1995, the licensee reported a condition of low level radioactivity in the canal aquatic algae that was transported to the South Dade landfill. (Refer to section 7.2.2 for additional information). The annual emergency plan exercise was conducted on March 22, 1995. (Refer to section 7.2.3 for additional information.)

4.0 Plant Operations (40500, 71707, 92901, and 93702)

4.1 Inspection Scope

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 forced outage 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 including PNSC, QA/QC audits and reviews, line management self-assessments, individual self-checking techniques, and performance indicators.

4.2 Inspection Findings

4.2.1 Plant and Component Labelling

During the conduct of an OSP on the 3A EDG (Refer to section 5.2.3 for additional information.), the inspectors noted labelling deficiencies in the 3A and 3B EDG fuel oil day tank rooms. The 3A EDG tank level switch labels (LS-1561A and 1553A) were switched, and the 3B EDG tank level switch LS-1553B was painted over and unreadable.

The inspectors verified that the LS isolation valves' labels were correct. The inspectors discussed this item with operations personnel, and the labels were corrected.

The inspectors also noted minor valve labeling as well as plant drawing deficiencies associated with certain PAHM valves. The valve labeling deficiencies were limited only to the valve noun name on valve tags. The valve number, valve lineup requirements during test and standby, and actual valve positions were correct. The plant drawing deficiency was introduced following a PCM that was performed in 1984. The plant drawing associated with the PAHMs was not updated to include the newly installed PAHM test valves. The P&ID for the PAHM system does not go into details associated with the PAHM instrument and therefore does not include the PAHM test valves.

The inspector determined that the above mentioned deficiencies had low safety significance. Additionally, the licensee is addressing the issue through condition report 95-161. The inspector also concluded that the system engineer was knowledgeable and responsive to inspector questions.

4.2.2 Load Reduction and Shutdown of Unit 4 for Secondary Plant Testing and Primary Valve Repairs

On March 3, 1995, the licensee reduced power on Unit 4 to perform secondary plant testing and maintenance. At 9:50 p.m. on March 4, 1995, during power escalation with the unit at 60%, operators observed dual indication on CVCS letdown orifice isolation valve CV-4-200A. The CVCS analog letdown flow indication was at 0 gpm, and ERDADS letdown flow indication was at 5 gpm. As a result, the licensee declared valve CV-4-200A inoperable. Valve CV-4-200A is an automatic, Phase A, containment isolation valve located inside containment and it is part of the RCS pressure boundary. This valve was manufactured by Copes-Vulcan; and in this particular application, it is an air-to-open spring-to-close valve. In response to the indicated loss of letdown flow, the licensee established excess letdown. Because one of the containment isolation valves in penetration No. 14 was inoperable, the licensee isolated the affected penetration by closing and de-activating letdown isolation valve CV-4-204 at approximately 10:43

p.m. in order to comply with action statement 6 of Technical Specification 3.6.4. This action secured normal letdown and limited the available RCS turnover rate to excess letdown (approximately 8-15 gpm).

At 3:40 a.m. on March 5, 1995, I&C personnel determined by local indication that valve CV-4-200A was in its' fail safe condition (closed) and that misalignment of the limit switches and/or indicating arm was responsible for the intermediate remote position indication. The inspection also identified that the stem of the valve was visibly bent. This was considered to be an indicator that the valve may not have been capable of meeting its required containment isolation leak-tightness criteria of 3,000 cc/minute for the combination of valves CV-4-200A, B, and C in parallel. This was also sufficient cause to confirm that valve CV-4-200A was in fact inoperable.

Another licensee inspection of the air operator on valve CV-4-200A conducted on March 5, 1995, identified that there was extensive deformation of the diaphragm plate and some deformation of the operator base. Based on these findings, structural damage to other related operator components was believed to have occurred. Since the diaphragm plate is used as a reaction surface for the closure spring, it was determined that although the valve was closed (with an undetermined leakage condition), it could not be relied upon to remain closed. In addition, the licensee suspected that the valve bolting and internals could have been damaged due to the possibility that the valve operator may have been subjected to excessive forces and due to possible extension of the valve.

Because of the impracticability of performing repairs and testing while on line, the licensee reduced reactor power and opened the reactor trip breakers at 10:02 p.m. on March 6, 1995. Subsequent RCS leak inspections revealed a small stud leak on letdown control valve LCV-4-460 and a small body-to-bonnet leak (dry boric acid deposits only) on pressurizer spray valve PCV-4-455A. In order to facilitate the repair of these leaks, the licensee was required to cool the plant down to Mode 5 (Cold Shutdown).

Due to the difficulty of degassing and borating the RCS to cold shutdown boron concentration with minimal letdown flow, engineering was requested to advise the plant of the feasibility of re-establishing normal letdown flow through either valve CV-4-200B or C. After consulting with the valve vendor, engineering informed the plant that un-isolating valve CV-4-200A by opening CV-4-204 would not result in any additional loading to the damaged components. This was based on the plug of the valve being held on the main seat by a spring force in excess of the system pressure forces when unisolated. As such, no travel of the stem was expected, and no further compression of the spring would result. Therefore, no additional loading would be placed on the damaged operator components. As a result, the licensee subsequently

conducted boration, degasification, and cooldown using normal letdown. Technical Specification 3.6.4, action statement d, which requires the unit to be in Cold Shutdown within 30 hours due to an unisolated and inoperable containment isolation valve, was entered during this period (from 10:20 a.m. on March 7, 1995, when letdown isolation valve CV-4-204 was re-powered until 1:03 a.m. on March 8, 1995, when Unit 4 entered Mode 5).

Although the repair of the leaking pressurizer spray valve was not required by the technical specifications, procedure 0-ADM-115, Notification of Plant Events, required the licensee to make a voluntary event notification to the NRC operations center because a mode reduction was made in accordance with technical specifications. The licensee made this voluntary notification at 10:40 a.m. on March 7, 1995.

Following disassembly and initial inspection of both the valve and actuator for valve CV-4-200A, the licensee determined that the initiating source of damage was the failure of the four operating base plate to yoke cap screws (bolts). (Refer to section 6.2.5 for additional information.) There was no visible damage to any of the valve internals or pressure retaining elements with the exception of minor bending of the upper stem. The plug was seated tightly and required a light tap to be freed. This was an expected condition given the impact received when the plug was seated without the normal restraining force of air being bled off the valve operator. In addition, the licensee determined that although minor yielding had occurred, the diaphragm plate had retained it's functional ability to contain the closure spring loading. This was based on the fact that the diaphragm plate bolt holes showed no tearing or visible enlargement. Therefore, contrary to initial indications, there had been no potential for actual loss of the containment isolation function for CV-4-200A.

The licensee subsequently reworked valve CV-4-200A and replaced the valve actuator. The licensee also installed a temporary handwheel on letdown control valve LCV-4-460 per safety evaluation No. JPN-PTN-SEMP-95-008 and repaired the body-to-bonnet leak on pressurizer spray valve PCV-4-455A. (Refer to section 6.2 for additional information.)

Following these repairs and the applicable testing, the licensee commenced a Unit 4 heatup at 1:15 a.m. on March 11, 1995. Criticality and Mode 1 were re-achieved at 4:43 a.m. and 7:30 a.m. on March 12, 1995. The licensee placed Unit 4 back on line at 8:07 a.m., and 100% reactor power was attained at 6:20 p.m. on the same day.

The inspectors witnessed various portions of the licensee's operational, maintenance, and engineering activities and reviewed the applicable documentation. Licensee management involvement and

interdepartmental teamwork were evident, and the unit shutdown and restart activities were conducted in a professional manner.

4.2.3 Reactor Coolant System Loops Filled

The licensee identified that both units had been in a condition that was prohibited by Technical Specification 3.4.1.4.1. This technical specification requires shutdown cooling in Mode 5 with either two loops of RHR or with one loop of RHR and two steam generators for natural circulation. The technical specification in this case applies for an RCS loops filled condition. Without the RCS loops filled, Technical Specification 3.4.1.4.2 applies, which requires both RHR loops operable. The problem which the licensee identified was with the interpretation of RCS loops filled. Previously, the licensee assumed that maintaining pressurizer level above 10% after RCS fill and vent met the RCS loops filled requirement.

During the last Unit 4 refueling outage (October through November 1994), the licensee pursued with Westinghouse the definition of RCS loops filled. Subsequently, in reviewing operating experience information, the licensee noted that two plants (South Texas Project and Vogtle) had also identified this issue and had made reports to the NRC. The licensee initiated condition report No. 95-053 on January 23, 1995. Subsequent review by the PNSC concluded that this issue was reportable as a technical specification violation, and the licensee issued LER 50-250/95-002, on March 13, 1995.

The licensee concluded that in order to achieve RCS natural circulation and to meet the RCS loops filled definition, the RCS must remain pressurized (with or without a pressurizer bubble) greater than 100 psig after completing fill and vent procedures. Otherwise, both loops of RHR must be operable. Further, the licensee also concluded that during integrated safeguards testing from 1991 to present, the technical specification was violated. (The RCS loops filled technical specification was revised in 1991).

During safeguards testing, the RHR pump (train) being tested was available. However, the licensee considered the RHR pump technically inoperable due to test equipment installation. Since 1991, this has occurred three times on each unit for about an 8-hour shift per train. Further, the RCS was vented through the pressurizer and head vent valves and the pressurizer level was 80%. These valves could have been closed in a short time period. Further, since this occurred at the end of an outage, the decay heat load was low. The licensee estimated 24 hours to reach RCS boiling with no RHR loops or natural circulation unavailable.

Licensee corrective actions included the following:

- issuance of a technical specification position statement (No. 95-001) to define RCS loops filled as requiring the RCS filled, vented, and greater than 100 psig,

- training of operators and plant personnel regarding Technical Specifications 3.4.1.4.1 and 3.4.1.4.2 and related issues,

- revision of administrative and implementing procedures to reflect the current RCS loop filled definition and minimum RHR and steam generator operability requirements, and

- further review of this issue for RCS loops filled and allowable steam generator and pressurizer levels to determine whether or not natural circulation could be established.

The inspectors reviewed this item, including the LER, the condition report, related evaluations, and the applicable technical specifications. The inspectors attended the PNSC meeting and discussed this item with licensee personnel. The inspectors also discussed the generic implications with NRC regional and headquarters personnel. Based on the availability of both RHR loops (one operable and one inoperable but available under test), and no actual loss of RHR in this condition, and the in-place approved ONOPs; the inspectors concluded that this issue has minor safety significance. Further, a low decay heat load and the ability to pressurize the RCS in order to establish circulation, further reduces the severity of this issue. The failure to meet Technical Specification 3.4.1.4.1 is a violation. However, this meets the criteria in 10 CFR Part 2, section VII.B for a licensee identified, non-cited violation. This will be tracked as NCV 50-250,251/95-06-02, Inadequate Definition of RCS Loops Filled. LER 50-250/95-002 and the NCV are closed.

4.2.4 Aquatic Algae and Grass Fouling of the Intake Structure

Turkey Point currently utilizes an extensive cooling canal system for its ultimate heat sink. Unlike typical cooling ponds which are elevated with surrounding dikes and contain fresh water, the Turkey Point cooling system is located at sea level and contains salt water because the underlying rock was too porous for an elevated design. This system is made up of a series of shallow parallel canals in an area approximately five miles long and two miles wide. The cooling water surface area of this system is about 4,000 acres, and the berm land surface area is about 1,700 acres. It takes approximately 52 hours for water leaving the plant discharge structure to traverse this 168-mile long system and return to plant intake structure. This canal system also serves as the habitat for approximately 35 adult and juvenile

american crocodiles (an endangered species) which periodically nest in the canal system.

Since 1993, the licensee's land utilization group has been performing an on-going long-term, maintenance and enhancement program for the cooling canal system. This program was designed to maintain the system in its present good condition and to increase the water surface area by 1% per year by controlling underwater growth (aquatic algae and seagrass) in the canals, keeping the berm land areas cleared, and widening the canal edges on a periodic basis to add water surface area and reduce erosion. (Refer to section 6.2.5 of NRC Inspection Report No. 50-250,251/94-13 for additional information.)

Significant rain storm activity following a dry spell dislodged a large quantity of aquatic algae and grass in the cooling canal system on the afternoon of March 8, 1995. This was first noted at about 4:00 p.m. This material floated underneath the canal system's floating booms, entered the plant's intake structure with little warning, and created high differential pressures across the travelling screens. Based on the potential risk of cavitating the circulating water and intake cooling water pumps, the licensee reduced Unit 3 reactor power from 100% to 60% at 5:30 p.m. as a conservative measure. (Unit 4 was in Mode 5 at the time in order to repair a leaking letdown containment isolation valve and a leaking pressurizer spray valve. Refer to sections 4.2.2 and 6.2.5 for additional information.) The aquatic algae and grass challenged the capacity of the travelling screens and screen wash system, and some overflowed into the suction bays of the ICW and circulating water pumps. As a result, the licensee began using the Unit 4 screen wash system to assist in the cleaning of the Unit 3 travelling screens. The licensee also began cleaning the screen wash strainers and both the CCW and TPCW basket strainers which filter the ICW supplies to the respective heat exchangers. By approximately 6:00 p.m., the quantity of aquatic algae and grass in the intake structure was at a manageable level, but the licensee conservatively decided to keep Unit 3 at 60% reactor power overnight in case of another influx. The licensee also began to make plans to install additional floating booms in the canal system to stifle the flow of the material without hindering the cooling water flow.

At 4:35 a.m. on March 9, 1995, while cleaning the 3A CCW basket strainer (one of two 100% capacity basket strainers which supplies ICW to a common header and then to three 50% capacity CCW heat exchangers), the licensee noticed that the required ICW supply flows to the CCW heat exchangers had decreased below the limit specified by the CCW heat exchanger performance results and curves in the procedures 3-OSP-019.4, Component Cooling Water Heat Exchanger Performance Monitoring, and 3-OP-019, Intake Cooling Water System. This was due to extensive fouling of the in-service ICW/CCW basket strainer. This placed Unit 3 in a 1-hour action

statement in accordance with Technical Specifications 3.7.2, 3.7.3, and 3.0.3. The licensee completed cleaning the 3A CCW basket strainer and returned it to service at 5:21 a.m. The flow increased above the minimum required levels at that time, and the licensee subsequently removed the 3B CCW basket strainer from service for cleaning.

The licensee reported this event to the NRC Operations Center per 10 CFR 50.72(b)(1)(ii)(B), outside design basis, at 5:30 a.m. on March 9, 1995, and notified the senior resident inspector at home. The licensee also briefed representatives from the NRC resident, regional, and NRR offices of its evaluation and corrective actions regarding this event via telecon at 11:30 a.m. on March 9, 1995. In addition, the licensee cleaned the condenser waterboxes prior to returning Unit 3 to 100% power at 11:40 a.m. on March 10, 1995. The licensee also generated condition report Nos. 95-180 and 95-181 regarding the issues associated with this event.

The inspectors noted that in order to clean (either backwashing or mechanically) the ICW to CCW basket strainers the 72-hour technical specification 3.7.3.c action statement had to be entered. This was entered numerous times during the event and following. The inspectors questioned whether or not the assumptions in the PSA relative to ICW loop availability were being met. Both the licensee's system engineering and self-assessment team had also identified this issue. Historical cleaning of these basket strainers has exceeded the out-of-service assumptions for ICW. The licensee is currently pursuing this issue.

The resident inspectors followed up on this event by reviewing the applicable technical specifications, procedures, curves, logs, and system diagrams; by discussing the event and design basis with the system engineer and plant management; and by observing the load reduction and intake structure and strainer cleanup activities locally and in the control room. The inspectors also toured the canal system, examined the algae and grass material, and reviewed the licensee's program for canal maintenance. The inspectors noted that operations personnel handled that load reduction in a professional manner, that operations personnel were knowledgeable of the technical specification and procedural requirements, that licensee management personnel were involved, and that interdepartmental teamwork was a strength. The operations manager and plant general manager were noted to be in the control room and the plant providing appropriate oversight during this event. The inspectors also verified that aquatic algae quantities in the intake structure were returned to manageable levels. In addition, the inspectors noted that this issue was reviewed in depth by the licensee's service water operational performance self-assessment team during the week of the event and by the NRC service water inspection team during the week of March 20, 1995. Further, the licensee intends to issue an LER for this event. (Refer to NRC

Inspection Report No. 50-250,251/95-08 for additional information.)

4.2.5 (Closed) URI 50-250,251/95-04-02, Missed Operator Round

The licensee identified a missed round by an ANPO in November 1994. The round required a non-safety-related hydrogen tank reading located at the adjacent fossil plant. The hydrogen is provided to the units' main generators and to the VCTs. The inspectors have concluded that this constitutes a violation for failure to perform procedure 0-OSP-201.4, ANPO Daily Logs. However, this meets the criteria in 10 CFR 2, section VII.B for a licensee identified, non-cited violation. This will be tracked as NCV 50-250,251/95-06-01. The URI and NCV are both closed.

5.0 Maintenance (61726 and 62703)

5.1 Inspection Scope

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.

5.2 Inspection Findings

5.2.1 Maintenance Activities Witnessed

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

- boric acid system repairs (Refer to section 5.2.5 for additional information.),

- replacement of the Unit 3 turbine mechanical trip gauges (Refer to section 5.2.6 for additional information.),

- Unit 4 auxiliary oil pump repair and replacement (Refer to section 6.2.1 for additional information.),

- repair of letdown containment isolation valve CV-4-200A per procedure 0-GMM-102.16, Copes-Vulcan Air-Operated Control Valve Maintenance (Refer to section 6.2.5 for additional information.), and

- pressurizer spray valve (PCV-4-455A) freeze seal and leak repair per PWO 95007001 and procedure 0-GMM-102.5, Freeze

Seal Application. (Refer to section 6.2.8 for additional information.)

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.

5.2.2 Surveillance Testing Activities Observed

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

- procedure 3-OSP-068.2, Containment Spray System Inservice Test;

- procedure 4-OSP-075.2 Auxiliary Feedwater Train 2 Operability Verification;

- procedure 0-SME-091.1, Fire and Smoke Detector System Semi-Annual Test;

- rapid start test for 3A EDG per procedure 3-OSP-023.1, Diesel Generator Operability Test (Refer to section 5.2.3 for additional information,); and

- procedure 3-OSP-200.3, Secondary Plant Periodic Test. (Refer to section 5.2.6 for additional information.)

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

5.2.3 3A Emergency Diesel Generator Rapid Start Test

The inspectors observed procedure 3-OSP-023.1, Diesel Generator Operability Test, section 7.3, for a rapid local start test for the 3A EDG. The inspectors verified that all prerequisites were met, all steps were conducted, that personnel were knowledgeable and appropriately briefed, that the OSP was followed correctly, and that test acceptance criteria were met.

The inspectors noted that the test was performed by a licensed and non-licensed operator in the field, and that an ANPS provided supervisory oversight. Operations' test conduct, EDG knowledge, and procedure compliance were noteworthy. Further, the inspectors noted that the EDG system engineer was present during the test to monitor EDG performance.

5.2.4 ICW Valve Stem Blocking Device

At 8:30 a.m. on February 23, 1995, during routine preventive maintenance on ICW manual valve 3-50-308, the stem blocking device loosened causing the valve to close. This isolated the B loop of ICW for Unit 3 resulting in an unplanned entry into a 72-hour Technical Specification 3.7.3 action statement. Mechanical maintenance personnel immediately restored the stem blocking device, and reopened the valve within 15 minutes. Since the ICW headers are normally cross-connected, no cooling was interrupted as the A loop supplied all ICW cooling loads.

The licensee initiated condition report No. 95-152 to identify root cause and to determine corrective actions. Root cause was determined to be vibration which caused the stem blocking device to loosen, and eventually become disengaged when the valve actuator key was removed. The licensee revised procedure 0-PMM-019.10, Intake Cooling Water Butterfly Valve Operator Inspection, to ensure that lock washers and a torque value were added. Further, maintenance personnel were informed of this item during shop meetings.

The inspectors learned of this event during routine condition report and operator log reviews. The inspectors verified corrective actions and discussed the event with maintenance personnel. The stem locking devices and the valves in the field were also examined. The inspectors noted that entry into Technical Specification 3.7.3 was recognized after the fact by the NPS, and appropriate log entries were made. The inspectors concluded that maintenance appropriately responded to this procedure weakness.

5.2.5 Boric Acid System Repairs

As discussed in section 6.2.4 of NRC Inspection Report No. 50-250,251/94-04, the licensee identified numerous through-wall leaks in the boric acid supply piping for both units (common system). During the current inspection period, the licensee continued with repair and pipe replacement activities. Further, additional leaks were identified and the licensee preformed metallurgical analyses of the leak areas.

The licensee has divided the leaks into nine zones for repair and replacement. At the close of this inspection period, six zones had been completed, included the ASME required system hydrostatic testing. The licensee concluded that leaks were caused by transgranular stress cracking corrosion. This was apparently due to a susceptible material (e.g., stainless steel), a high temperature from the abandoned heat tracing, the presence of contaminants (e.g., halogen and moisture), and a residual stress from welding. The licensee intends to document these findings in a special report.

The inspectors observed the maintenance and hydrostatic testing activities in the field, reviewed work packages and clearance boundaries, and discussed this item with maintenance, engineering, and operations personnel. Several zones would have required technical specification LCO entry; however, the licensee made repairs during the Unit 4 forced outage while in Mode 5 when that portion of the system was not required to be operable.

Further, the inspectors noted that the licensee developed alternate flow paths and system alignments which maintained system operability, thus preventing the need for LCO entry. This was accomplished per procedure TP-1146, Realignment of 4A Boric Acid Transfer Pump to supply Unit 3.

The inspectors concluded that repair activities were appropriately conducted with strong teamwork. Further, the licensee demonstrated conservatism in not entering LCO action statements while effecting the repairs. The final disposition of this issue, including the metallurgical report, will be reviewed by regional specialist inspectors.

5.2.6 Unit 3 Turbine Front Standard Testing and Maintenance

On March 20, 1995, the licensee replaced the turbine front standard mechanical trip gauges and performed procedure 3-OSP-200.3, Secondary Plant Periodic Tests. The inspectors noted good preplanning by I&C maintenance, conservative use of a "red sheet", strong oversight by both QA and operations management, and strong procedural compliance by operators. The system engineer was also involved in the testing and maintenance activities.

6.0 Engineering (37551, 90712, 90713, 92700, and 92903)

6.1 Inspection Scope

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.

In addition, the inspectors reviewed one previous open item to assure that corrective actions were adequately implemented and resulted in conformance with regulatory requirements.

6.2 Inspection Findings

6.2.1 Unit 4 Auxiliary Oil Pump Failure

During the Unit 4 forced outage on March 8, 1995, the auxiliary oil pump motor breaker tripped on overcurrent. Licensee investigation determined the pump had failed. This pump provides high and low pressure oil to the main turbine during times when the attached (front standard) oil pump is unavailable (e.g., less than 1800 rpm turbine speed). The pump has two impellers on a common shaft. The impellers are made of bronze, and the licensee found bronze metal throughout the lube oil system.

The licensee installed a spare pump, rebuilt the failed pump, and cleaned the oil system using filtration systems. The auxiliary oil pump and oil systems were returned to service to support unit restart on March 12, 1995. The license concluded that the pump failure was caused by impeller impact due to a failure of a pin on the collar causing the impeller to move upwards and impact the pump casing. Root cause determinations are pending.

The inspectors reviewed this event by examining the failed pump, by observing repairs and replacement activities, and by monitoring oil cleanup evolutions. The inspectors noted the licensee established an ERT to followup on this item. The inspectors attended selected ERT meetings and discussed this item with the ERT leader and plant management personnel. The inspectors noted that future plans include root cause determination, potential system redesign, additional testing, and contacting other plants. The inspector concluded that the licensee, including ERT involvement, appropriately reviewed this failure.

6.2.2 Pressure Locking of Motor-Operated Valves

During the inspection period, the inspectors were informed of an issue relative to a RHR containment sump MOV pressure locking problem at another facility. Information Notice 95-14, Containment Sump Suction Gate Valve Susceptibility to Pressure Locking, was subsequently issued. The inspectors reviewed the IN and other related technical information to determine applicability at Turkey Point.

NRC Inspection Report No. 50-250,251/93-25, section 2.6 previously reviewed this item. That report documented review of previous industry information including NRC Information Notices, INPO

SOERs, and NRC Generic Letters. Further, licensee safety evaluations (JPN-PTN-SEMJ-89-066 and JPN-PTN-SEMP-94-034) were also reviewed. The NRC previously concluded that the licensee had appropriately addressed this pressure locking issue.

The inspectors reviewed this issue of MOV pressure locking and the specifics at Turkey Point for the Unit 3 and 4 RHR containment sump suction valves (MOVs-860A and B, and MOVs 861A and B). Per the above referenced safety evaluations, the licensee stated that these valves were excluded from having a specific engineering evaluation because the MOVs were appropriately vented. The licensee stated that MOVs-860A and B have an interdisc external relief line and that MOVs-861A and B have a 3/16-inch hole drilled in the downstream disc.

The inspectors reviewed plant drawings, walked down the MOVs in the plant, and discussed this item with engineers. The inspectors confirmed the venting arrangement for MOVs-860A and B; however, the arrangement for MOVs-861A and B could not be immediately confirmed. Neither the P&ID (5613/4-M3050) nor the valve vendor (Westinghouse) drawings (5610-M-1200-45 and 65) depicted this drilled hole in the valve disc. The inspectors also examined a spare disc in the central receiving facility warehouse and reviewed engineering data base information (e.g. TEDB). Based on the above, the inspectors could not confirm the existence of a drilled hole in the valve disc.

Based on these concerns, the licensee initiated a condition report (No. 95-168) and pursued this apparent discrepancy. The licensee located the original Westinghouse P&ID (drawing 5610-M-470-5). This drawing denoted a 3/16 inch hole drilled in one valve disc for MOVs-861A and B. Further, the licensee reviewed maintenance history and concluded these MOV discs have not been replaced. The licensee also reviewed current application for these valves, noting that they are susceptible to pressure locking during normal RHR shutdown cooling and no failures were identified. Also, the licensee stated that MOVs-861A and B are downstream of MOVs-860A and B, are therefore less susceptible to pressure locking during accident (containment sump) operation. The limitorque actuator has a capability of 500 ft-lbs which provides margin above the 220 ft-lbs requirement.

The licensee committed to addressing these apparent documentation issues for MOVs-861A and B in both the P&IDs and vendor drawings. In addition, the licensee stated that they would review other related documents to check for any additional problems.

The inspectors concluded that the licensee was responsive to the inspectors' questions and concerns, and that this issue was appropriately resolved. The inspectors intend to review longer term corrective actions in a future inspection.

6.2.3 ITE-Siemens Circuit Breakers

During storm recovery operations, licensee personnel noted a potential abnormality with stripped screws in the casing for model HE3 molded case spare circuit breakers manufactured by ITE-Siemens. The stripped screws are for the hold down bar for the trip cam assembly. These breakers were procured as safety-related from Farwell and Hendricks, and are used in 480 Volt AC MCC applications. They were stamped as date coded "0591", and manufactured in Wilmington, NC from 1986-1991. This deficiency could prevent the breaker from resetting, or cause inadvertent tripping.

The licensee initiated condition report No. 95-083 and evaluated the safety impact on the plant. The electrical maintenance group tested these breakers prior to installation, and no problems were found with the installed breakers. The licensee provided assurance that these breakers would not trip open during a seismic event by performing testing at the Farwell and Hendricks facility, using the Turkey Point seismic profile. The licensee concluded that no operability issues existed for the 56 installed breakers (23 of which are safety-related) in both units. These breakers would remain closed as required. The breakers may not reset if opened; however, the licensee inspected and tested the installed breakers and did not identify any problem with them. The vendor is reviewing for 10 CFR Part 21 applicability due to a possible manufacturing defect. The licensee also contacted NRC headquarters (vendor branch) and made an INPO network notification. Turkey Point received the majority of these suspect breakers.

The inspectors reviewed the licensee's condition report, the affected breaker list, the seismic test results, the operability assessment, and discussed this item with site engineering personnel. The inspectors concluded that the licensee acted appropriately in dealing with this issue. The inspectors intend to review the 10 CFR Part 21 issue in a future inspection.

6.2.4 Turkey Point Response to 10 CFR Part 21 Notification

The inspectors reviewed the licensee's response to a 10 CFR Part 21 notification, dated January 30, 1995, pertaining to non-conforming diodes utilized as spare parts for certain Westronics chart recorders. The licensee inspected their inventory and identified two cards that had the suspect diodes. Additionally, the licensee determined that one card containing this diode was utilized on Control Rod Bank C position and insertion limit recorder. The licensee plans to replace the two cards containing the non-conforming diodes from the inventory. Additionally, a work request was written for I&C to inspect the recorder associated with the Control Rod Bank C position and insertion limit. This application is non-safety related.

The inspectors verified corrective actions and concluded that the licensee appropriately responded to the 10 CFR Part 21 notification in a timely manner.

6.2.5 Letdown Orifice Isolation Valve Bolt Failure Analysis

On March 4, 1995, CVCS letdown orifice isolation valve CV-4-200A failed in the closed position (Refer to section 4.2.2 for additional information.), and the licensee's initial visual inspection by maintenance personnel revealed the failure of 4 1/2-inch bolts which attached the valve yoke to the operator base plate. The bolts were specified as commercial steel and were thought to be original plant equipment. The upper portions of the four bolts were retrieved from the operator and forwarded to the licensee's metallurgical laboratory for analysis.

Visual examination revealed varying degrees of plastic deformation to all four bolts. The licensee concluded that two of the bolts had been subjected to tensile loads and that the other two bolts had been subjected to both tensile and bending loads. The licensee cleaned the fracture surface of one bolt in acetone and then examined it with a scanning electron microscope. A second bolt was sectioned and examined with a light optical microscope revealing a normal microstructure. The licensee analyzed the chemical composition of a third bolt using optical emission spectroscopy and found that it satisfied the requirements for AISI-1010 low carbon steel. Rockwell hardness testing was also performed on this bolt, and it revealed an average strength of 98 ksi. (The approximate yield strength for the alloy in this condition was 90 ksi.)

Given the valve design, the causative cyclic stresses would have been experienced only when the valve was in the open position. The licensee determined that the valve was exercised less than 1,000 times throughout its life; however, the number of causative cycles appeared to be greater than this value by at least one order of magnitude.

The licensee concluded that the failure mechanism of the four bolts attaching the yoke to the operator base plate of valve CV-4-200A were high cycle fatigue followed by ductile overload. The ultimate root cause of the bolt failures and the potential applicability to other similar Copes-Vulcan valves is still under analysis and is currently scheduled to be completed by April 15, 1995. The plant uses similar valves and they would fail in the safe position consistent with their design, and they would remain in the safe position and intact due to the imposed spring load of 10,400 pounds force. (The design RCS pressure force is approximately 4,400 pounds force.) The licensee also tasked engineering with developing a long-term inspection plan and any necessary corrective actions for Copes-Vulcan air-operated valves installed at Turkey Point. This action item is currently scheduled to be completed by May 15, 1995. These two actions are documented in the licensee's condition report and are being tracked on the plant general managers action item tracking system. The licensee is also currently considering whether or not this problem could be a 10 CFR Part 21 issue regarding a potential design weakness involving the grade of bolts used in this application for this vintage valve and the forces induced by the shape of the diaphragm operator base plate.

The inspectors attended some of the licensee's ERT meetings, witnessed portions of the valve repair, reviewed the licensee's condition reports, and reviewed the licensee's metallurgical laboratory analysis results. The licensee's engineering efforts in evaluating this failure were aggressive and comprehensive. The inspectors plan to followup on the licensee's long-term corrective actions during future inspections.

6.2.6 Licensee/NRC Engineering Meeting

An FPL/NRC engineering meeting was conducted at the Turkey Point site on March 14, 1995. Representatives from the licensee's Turkey Point, St. Lucie, and corporate offices as well as representatives from the NRC's Turkey Point and St. Lucie resident inspector offices were in attendance. The following topics were discussed:

- industry issues including an update on the thermo-lag issue, an update on neutron embrittlement, the status of Generic Letter 89-10 for both Turkey Point and St. Lucie, and an update of the maintenance rule for both Turkey Point and St. Lucie;

- maintenance and operations support including a St. Lucie engineering overview, a Turkey Point self-assessment, the St. Lucie design basis documents, reduction in operator workarounds at both Turkey Point and St. Lucie, the Turkey Point instrument air upgrade, abandoned equipment at Turkey Point, and the Turkey Point EDG sequencer update; and

- FPL long-range plans including the licensee's plans to meet future power needs, life extension, the thermal uprate for Turkey Point, 24-month fuel cycles for both Turkey Point and St. Lucie, and dry fuel storage.

This meeting was beneficial in understanding current engineering issues.

6.2.7 Rosemount Pressure Transmitters

Plant Saint Lucie experienced problems with certain Rosemount pressure transmitters that had been inadvertently manufactured with Monel sensor isolation diaphragms instead of required

stainless steel material. Monel allows permeation of hydrogen into the sensor assembly which dissolves in the transmitter sealing oil. During system pressure changes, the dissolved hydrogen comes out of solution and potentially causes pressure transmitters to behave erratically. Rosemount determined that approximately 500 units of these pressure transmitters were released.

Turkey Point searched their records and determined that four of these pressure transmitters were received at the site. Two of these were within the stores, one was found in the I&C maintenance shop, and one was shipped to Plant Saint Lucie. There were no suspect transmitters installed in the plant. Additionally, a QC hold was placed on the three transmitters that are on site to prevent installation. The licensee plans to return the suspect transmitters to Rosemount.

The inspectors concluded that the licensee was aggressive in resolving this issue. Rosemount is planning a notification pursuant to 10 CFR 21 with regard to this issue.

6.2.8 Unit 4 Pressurizer Spray Valve Body-to-Bonnet Leak

Following a Unit 4 shutdown on March 6, 1995, to repair a failed letdown orifice isolation valve, licensee RCS leak inspections revealed a small body-to-bonnet leak (dry boric acid deposits only) on pressurizer spray valve PCV-4-455A. In order to facilitate the repair of this leak, the licensee was required to cool the plant down, and Mode 5 was reached on March 8, 1995. (Refer to section 4.2.2 for additional information.)

The licensee established freeze seals to isolate the valve for disassembly, inspection, and repair. Inspection revealed that there were no scratches or steam cuts on the seating surfaces, but there was inadequate crush on a flexitalic gasket. The gasket seating surface gap was found to be 0.103 to 0.106 inches in lieu of the required 0.090 to 0.100 inches. The licensee replaced the bonnet extension with a new part from stores to restore the flexitalic gasket sealing gap to within tolerances, changed the applicable procedure to increase the torque from 800-1,000 foot pounds, and performed cold re-torquing to make up for any relaxation.

The licensee also performed a review of the leakage history for this valve during the last seven years. Since 1988, pressurizer spray valve PCV-4-455A has had the following leaks:

Date	Leakage	Corrective Action
05-88	Packing leak	Valve overhauled.

Date	Leakage	Corrective Action
02-07-90	Dry boric acid on valve flange	Boric acid residue cleaned with demineralized water. No leakage found.
08-21-90 to 10-01-91	Body-to-bonnet leak	Valve overhauled and bonnet extension replaced during the dual unit outage.
05-04-93	Body-to-bonnet leak	Valve overhauled.
03-09-95	Body-to-bonnet leak	Valve overhauled and bonnet extension replaced. Condition report and nuclear problem report written.

In addition, the licensee generated a condition report (No. 95-194) to review this issue and ensure adequate corrective action, and a root cause analysis and nuclear problem report are currently scheduled for completion by April 14, 1995. The licensee also plans to revise the mechanical maintenance procedures for Copes-Vulcan valves to ensure that gasket dimensions are within tolerances, to review the work order history for other pressurizer spray valves for repetitive leakage problems and establish a corrective action plan, and to add the requirement for a condition report to require a root cause investigation of any non-isolable leakage.

The inspectors observed portions of the establishment of the freeze seal and reviewed the applicable documentation for valve troubleshooting and repair. The licensees efforts in evaluating and repairing this problem were aggressive and comprehensive.

6.2.9 (Closed) URI 50-250,251/94-03-01, Technical Specification Interpretation Regarding Containment Isolation Valves

This issue concerned interpretation and applicability of Technical Specification 3.6.4, Containment Isolation Valves, for an event at Turkey Point in February 1994. The Unit 3 ECC CCW outlet valve (CV-3-2907) had a large packing leak. The valve is air-operated, fails open on an actuation signal, is a non-automatic CIV, and is part of closed loop system that penetrates containment. The licensee made repairs to the valve and did not consider CV-3-2907 to be a CIV as referenced in the technical specification.

This issue was reviewed by NRC regional and headquarters personnel. The NRC concluded that the licensee took appropriate action to correct the valve problem. Further, the issue relative to this CIV, its technical specification applicability, and

interpretations remains questionable. To address this, the licensee developed Technical Specification Position Statement No. 94-006 dated March 8, 1995. This PNSC approved document, stated that only CIVs which are either phase A, phase B, or containment ventilation isolation valves (per UFSAR Table 6.6-3) are applicable to technical specification 3.6.4. Further, PC/M No. 89-581, Revision 1, updated the UFSAR sections for CIVs, and the licensee intends to issue this during the next UFSAR revision.

Based on the NRC headquarters and regional reviews, on the UFSAR revision, and on the position statement; this URI is resolved and closed.

6.2.9 Monthly Operating Report

The inspectors reviewed the February 1995 monthly operating report and determined it to be complete and accurate.

7.0 Plant Support (71750)

7.1 Inspection Scope

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.

7.2 Inspection Findings

7.2.1 Unit 4 Containment Tours

During the Unit 4 forced outage (section 4.2.2), the inspectors made several containment tours. On March 7, 1995, with Unit 4 in Mode 3, the inspectors toured the containment checking for fluid leaks. The inspectors reviewed completed procedure OP-0206.7, Containment Visual Leak Inspection, which was performed at 11:00 p.m. on March 6, 1995. The inspectors verified that the licensee's results and findings were accurate, with one exception. The inspectors noted a leak emanating from the lagging under MOV-3-865A (3A accumulator outlet valve). Subsequent inspections determined the leak source to be a combination of an identified packing leak on CV-4-851A and an unidentified leak on a swagelock fitting on the packing leakoff line. The licensee repaired all these leaks.

The inspectors noted very good radiological controls during all entries. Overall containment cleanliness and housekeeping was also very good.

7.2.2 Aquatic Algae Radioactive Contamination

As followup to the March 8-9, 1995, canal algae intrusion event (Refer to section 4.2.4 for additional information), the licensee determined that radioactivity was present. Radioisotopic analyses noted low levels of activated corrosion products, primarily Manganese-54. The state of Florida was informed, and on March 21, 1995, the licensee made a 10 CFR 50.72 notification to the NRC. The state of Florida also sampled the algae and results were similar. Since 1994, the licensee had been transporting this algae and other biological material from screen and strainer backwashes to the South Dade County landfill. This was to conform to state regulations pertaining to waste disposal (non-radioactive). Past and recent surveys of the landfill have not detected any radioactivity.

The inspectors discussed this issue with licensee personnel, observed selected isotopic analyses and results, and discussed this with NRC regional and headquarters specialists. The inspectors monitored the NRC notification, and intend to continue to follow this issue. Further, NRC Inspection Report 50-250,251/95-05 also addressed this issue.

7.2.3 Practice Drill and Annual Emergency Preparedness Exercise

In order to test the emergency facilities including the control room (simulator), the on-site TSC and OSC, and the off-site EOF during this inspection period; the licensee conducted a practice drill (Refer to section 7.2.2. of NRC Inspection Report No. 50-250,251/95-04 for additional information.) on March 16, 1995, and an annual emergency preparedness drill on March 22, 1995. The licensee also critiqued each drill.

The inspectors observed and participated in these activities, and the inspectors concluded that the licensee adequately tested its emergency facilities and activated its emergency plan. Drill critiques were effective in identifying issues and providing feedback to the participants. (Refer to NRC Inspection Report No. 50-250,251/95-07 for additional information.)

7.2.4 Offsite Notification Due to Fatal Car Crash

At about 11:30 p.m. on March 24, 1995, a fatal car crash occurred on the Turkey Point access road within the owner controlled area. The licensee reported this to NRC per 10 CFR 50.72, section (b)(2)(2ii) and notified the senior resident at home. The individual was not an FP&L employee or a contractor worker at Turkey Point. Local law enforcement personnel investigated the event.

The inspectors reviewed licensee actions and deemed them to be appropriate.

8.0 Exit Interview

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 24, 1995. (Refer to section 1.0 for exit meeting attendees.) The areas requiring management attention were reviewed. 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. The inspectors had the following findings:

Item Number	Status, Description, and Reference
50-250,251/95-06-01	(Closed) NCV - Missed Operator Round; Failure to Follow OSP (section 4.2.5)
50-250,251/95-06-02	(Closed) NCV - Inadequate Definition of RCS Loops Filled; Failure to Meet Technical Specification 3.4.1.4.1 (section 4.2.3)

Additionally, the following previous items were discussed:

Item Number	Status, Description, and Reference
50-250,251/95-04-01	(Closed) URI - Missed Operator Round (section 4.2.5)
50-250,251/94-03-01	(Closed) URI - Technical Specification Interpretation Regarding Containment Isolation Valves (section 6.2.9)
LER 50-250/95-002	(Closed) LER - Inadequate Definition of RCS Loops Filled (section 4.2.3)

9.0 Acronyms and Abbreviations

AC	Alternating Current
ADM	Administrative
AFW	Auxiliary Feedwater
AISI	American Iron and Steel Institute
ALARA	As Low As Reasonably Achievable
a.m.	Ante Meridiem
amp	Ampere
ANPO	Associate Nuclear Plant Operator
ANPS	Assistant Nuclear Plant Supervisor
CC	Cubic Centimeters
CCW	Component Cooling Water
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
CIV	Containment Isolation Valve
CV	Control Valve

CVCS	Chemical Volume Control System
ECC	Emergency Containment Cooler
EDG	Emergency Diesel Generator
e.g.	For Example
EOF	Emergency Offsite Facility
ENS	Emergency Notification System
ERDADS	Emergency Response Data Acquisition and Display System
ERT	Event Response Team
°F	Degrees Fahrenheit
FCV	Flow Control Valve
FPL	Florida Power and Light
ft-lbs	foot pounds (torque)
GL	Generic Letters
GMM	General Maintenance - Mechanical
gpm	Gallons Per Minute
HP	Health Physics
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IN	(NRC) Information Notice
JPN	Juno Project Nuclear (Nuclear Engineering)
Ksi	1000 pounds per square inch
KV	Kilovolt
LCO	Limiting Condition for Operation
LCV	Level Control Valve
LER	Licensee Event Report
LS	Level Switch
LT	Level Transmitter
MCC	Motor Control Center
MOV	Motor-Operated Valve
NCV	Non-Cited Violation
NPO	Nuclear Plant Operator
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NWE	Nuclear Watch Engineer
ONOP	Off-Normal Operating Procedure
OP	Operating Procedure
OSC	Operational Support Center
OSP	Operations Surveillance Procedure
P21	10 CFR Part 21
PAHM	Post-Accident Hydrogen Monitor
PC/M	Plant Change/Modification
PCV	Pressure Control Valve
P&ID	Piping and Instrumentation Diagram
p.m.	Post Meridiem
PMM	Preventive Maintenance - Mechanical
PNSC	Plant Nuclear Safety Committee
PSA	Probabilistic Safety Assessment
psig	Pounds Per Square Inch Gauge
PTN	Project Turkey Nuclear
PWO	Plant Work Order

PWR	Pressurized Water Reactor
QA	Quality Assurance
QC	Quality Control
RCS	Reactor Coolant System
RHR	Residual Heat Removal
rpm	Revolutions Per Minute
SEMP (J)	Safety Evaluation Mechanical - Juno
SME	Surveillance Maintenance - Electrical
TEDB	Total Equipment Data Base
TP	Temporary Procedure
TPCW	Turbine Plant Cooling Water
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item