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

Report Nos.: 50-335/86-07 and 50-389/86-06

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

Docket Nos.: 50-335 and 50-389 License Nos.: DPR-67 and NPF-16

Facility Name: St. Lucie 1 and 2

Inspection Conducted: March 11 - April 14, 1986

Inspectors: S. Guenther for 4/28/86
R. V. Crlenjak, Senior Resident Inspector Date Signed

S. Guenther for 4/28/86
H. E. Bibb, Resident Inspector Date Signed

Approved by: S. Guenther for 4/28/86
S. A. Elrod, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This inspection involved 245 inspector-hours on site in the areas of Technical Specification (TS) compliance, operator performance, overall plant operations, quality assurance practices, station and corporate management practices, corrective and preventive maintenance activities, site security procedures, radiation control activities, surveillance activities, and refueling activities.

Results: One violation was identified (paragraph 8).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*K. Harris, St. Lucie Vice President
D. A. Sager, Plant Manager
*J. H. Barrow, Operations Superintendent
T. A. Dillard, Maintenance Superintendent
*L. W. Pearce, Operations Supervisor
R. J. Frechette, Chemistry Supervisor
C. F. Leppla, Instrumentation and Control (I&C) Supervisor
P. L. Fincher, Training Supervisor
C. A. Pell, Technical Staff Supervisor (Acting)
E. J. Wunderlich, Reactor Engineering Supervisor (Acting)
*H. F. Buchanan, Health Physics Supervisor
*G. Longhouser, Security Supervisor
*J. Barrow, Fire Prevention Coordinator
J. Scarola, Assistant Plant Superintendent - Electrical
*C. Wilson, Assistant Plant Superintendent - Mechanical
*N. G. Roos, Quality Control Supervisor

Other licensee employees contacted included technicians, operators, mechanics, security force members, and office personnel.

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on April 18, 1986, with those persons indicated in paragraph 1 above. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve a violation or deviation. A new unresolved item is discussed in paragraph 9.

4. Plant Tours (Units 1 and 2)

The inspectors conducted plant tours periodically during the inspection interval to verify that monitoring equipment was recording as required, equipment was properly tagged, operations personnel were aware of plant conditions, and plant housekeeping efforts were adequate. The inspectors

also determined that appropriate radiation controls were properly established, critical clean areas were being controlled in accordance with procedures, excess equipment or material was stored properly and combustible material and debris were disposed of expeditiously. During tours, the inspectors looked for the existence of unusual fluid leaks, piping vibrations, pipe hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment, and instrument calibration dates. Some tours were conducted on backshifts.

The inspectors routinely conducted partial walkdowns of emergency core cooling systems (ECCS). Valve, breaker/switch lineups and equipment conditions were randomly verified both locally and in the control room. During the inspection period, the inspectors conducted a complete walkdown in the accessible areas of the Unit 2 diesel generators and the Units 1 and 2 component cooling water (CCW) systems to verify that the lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory. Additionally, flowpath verifications were performed on the following systems: Units 1 and 2 chemical and volume control systems, high and low pressure safety injection systems and ac/dc electrical distribution systems.

5. Plant Operations Review (Units 1 and 2)

The inspectors, periodically during the inspection interval, reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs, operating orders, standing orders, jumper logs and equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. During routine operations, operator performance and response actions were observed and evaluated. The inspectors conducted random off-hours inspections during the reporting interval to assure that operations and security remained at an acceptable level. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. The inspectors performed an in-depth review of the following safety-related tagouts (clearances):

1-1-10	Unit 1 pressurizer surge line sample valve (V-5204 has [had developed] dual indication),
1-1-109	1B charging pump (repack seals, change oil),
1-4-21	1A auxiliary feed pump discharge valve (replace wiring [to implement] EQ of MV-09-9),
1-4-25	Unit 1 CCW surge tank (replace sight glasses),
2-4-71	Unit 2 pressurizer/reactor level tubing connections (install level instrument for refueling),
2-4-78	Unit 2 station air penetration no. 8 (local leak rate test),

2-4-79 Unit 2 high pressure safety injection system (engineered safeguards test), and

2-4-80 2B intake cooling water pump (inspect/replace discharge expansion joint).

On April 12, 1986, the licensee took Unit 1 off-line to plug a leaking condenser tube. The reactor remained in mode 2 during the repair. On April 13, at 1:40 a.m., while returning the reactor to power, an automatic reactor trip was initiated by a high-high steam generator water level signal. Plant power was at 17 percent and increasing, when the turbine throttle/governor valve opened more than expected, causing steam generator level to swell. Steam generator level was being controlled manually utilizing the 15 percent bypass valves. This unexpected steam generator level change caused a high-high level signal which initiated a trip of the operating main feed pump and a loss of turbine load signal, which causes a reactor trip when power is above 15 percent. All systems functioned as designed and no low steam generator level resulted from the transient. The cause of the trip was reviewed, the resident inspector was notified and a reactor restart was commenced at 4:25 a.m. Full power was achieved at approximately 6:30 p.m. on April 13.

6. Technical Specification Compliance (Units 1 and 2)

During this reporting interval, the inspectors verified compliance with limiting conditions for operation (LCO) and results of selected surveillance tests. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, switch positions, and review of completed logs and records. The licensee's compliance with LCO action statements was reviewed on selected occurrences as they happened.

7. Maintenance Observation

Station maintenance activities on selected safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review; LCOs were met, activities were accomplished using approved procedures, functional tests and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; and radiological controls were implemented as required. Work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment. The inspectors observed portions of the following maintenance activities (Plant Work Orders):

PWO-2627 Unit 2 main feedwater valve HCV-092B (add oil and precharge accumulator),

PWO-2628 2B diesel generator - 12 cylinder (idler pulley bolts broken), and

PWO-3612 Valve 1-SE-05-1B (excessive leakage for LLRT).

A problem was recently identified at another facility relating to bolt and nut failures caused by flame heating to aid in disassembly. In response to that finding, the licensee performed an investigation to determine if similar practices/failures existed at St. Lucie. The licensee's quality control (QC) inspectors questioned several mechanical inspectors who had witnessed work performed and were familiar with mechanical work practices during normal plant operations and outages. The only practice noted was that of using a cutting torch to remove "frozen" bolts or nuts. Since bolts and nuts removed by this process are rendered unusable, new materials are used during reassembly. Additionally, the QC department inspected a total of 1507 nuts on safety-related pressure retaining components on both units. No evidence of cracking or flame heating was found. The following is a list of the systems/components inspected:

- 1A and 2A auxiliary feedwater pumps,
- 1B and 2B auxiliary feedwater pumps,
- 1C and 2C auxiliary feedwater pumps,
- 1A and 2A train main steam safety relief valves,
- 1B and 2B train main steam safety relief valves,
- Steam dumps HCV-08-2A and 2B, and
- 1A main steam check valve.

8. Review of Nonroutine Events Reported by the Licensee (Units 1 and 2)

The following Licensee Event Reports (LERs) were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events which were reported immediately were also reviewed as they occurred to determine that the TSs were being met and that the public health and safety were of upmost consideration.

The following four LERs address missed surveillances and are considered closed:

a. LER 335/85-08: On September 29, 1985, the 25 percent time extension for the Unit 1 quarterly main steam isolation valve (MSIV) part-stroke surveillance test specified in TS 4.7.1.5 was exceeded. On October 7, 1985, the assistant nuclear plant supervisor (ANPS) performed a routine review of the surveillance scheduling procedure and noticed that the MSIV part-stroke surveillance had not been signed off. In an effort to determine whether the test had indeed been missed, the ANPS contacted the QC department to determine whether the surveillance test procedure had been processed. QC verified that a completed MSIV surveillance test procedure had not been processed. The ANPS immediately directed the operators to perform the missed surveillance. The plant remained at normal full power throughout the event. In summary, the error was identified by the licensee eight days after the expiration of the required time interval. Satisfactory completion of the required surveillance indicated that the MSIVs were operable during the period.

b. LER 389/86-03: On January 13, 1986, the licensee's QC department notified the I&C department that the 25 percent time extension for the performance of the auxiliary feedwater actuation system (AFAS) actuation surveillance testing had expired. Unit 2 TS Table 4.3-2 requires a monthly surveillance of the AFAS logic when the unit is in modes 1, 2, or 3. The AFAS logic surveillance had last been performed on December 3, 1985. Taking into account the 25 percent (seven-day) allowed extension, the surveillance was required to be completed no later than January 10, 1986. Following discovery of the missed surveillance, the I&C department made arrangements to immediately perform the required testing. The licensee performed the surveillance January 13, 1986. The results were satisfactory. The unit remained at full power during this period of time. In summary, the error was identified by the licensee three days following the expiration of the required time interval. The operators retained the capability of manually initiating the system from the control room. Satisfactory completion of the surveillance indicated that the AFAS was operable during the period.

c. LER 389/86-04: On February 10, 1986, reactor engineering personnel noted that the maximum allowable surveillance interval for the calculation and adjustment of fixed incore alarm setpoints, as required by Unit 2 TS 4.2.1.4, had been exceeded. Taking into account the 31-day requirement of the TS plus the 25 percent (seven-day) allowable extension, the surveillance was required to have been completed no later than February 7, 1986. Prior to February 10, the last previous incore alarm setpoints had been entered on December 30, 1985. Had the surveillance been performed, the incore alarm setpoints would have been updated using the January 28, 1986 core flux map. A review of the January 28 core flux map indicated that of the 224 new detector alarm setpoints, 11 would have been more restrictive than the December 30 setpoints. All 11 of the more restrictive setpoints were within two percent of the December 30 setpoints.

d. LER 389/86-05: On March 10, 1986, a licensee QC inspector reviewing the surveillance testing log noted that the time limit for the performance of the semi-annual engineered safety features actuation system (ESFAS) relay surveillance required by Unit 2 TS Table 4.3-2 had expired. This surveillance verifies that the desired components operate/actuate correctly when the individual ESFAS subgroup relays function. The due date for the next performance of the test was December 29, 1985; the 25 percent time extension expired on February 13, 1986. Preparations were made and the surveillance was completed on March 10. In summary, the error was identified by the licensee 31 days following the expiration of the required time interval. Successful completion of the test on March 10 demonstrated that the system was operable during the time period in question.

These LERs represent four examples of missed surveillances which occurred over a six month period and together are indicative of a programmatic/ implementation failure in the licensee's procedures for the tracking and scheduling of surveillance testing. This is a violation (335/86-07-01, 389/86-06-01).

The following LER addresses a problem with the Unit 1 iodine removal system and is considered closed:

e. LER 335/86-03: On February 14, 1986, while operating at 100 percent power, a licensee review of plant operating logs revealed an unexpected increase in the level of the sodium hydroxide (NaOH) addition tank. NaOH is used as an additive in the containment spray system to aid in iodine removal. The NaOH tank was sampled and the concentration was found to be 26.1 percent. This was below the TS 3.6.2.2.a limit of 30 percent. The iodine removal system was declared out of service at 11:00 a.m. While preparations were made to restore the proper NaOH concentration, the cause of the increase in tank level was investigated. It was determined that leaking check valves allowed water from the refueling water tank (RWT) to leak into the NaOH tank, reducing the NaOH concentration. A flush of the check valves with demineralized water was not effective in reseating the check valves. When the check valves were disassembled and inspected, debris was found on the seating surfaces of the check valves and it was discovered that the check valves had been installed upside-down during plant construction (flow orientation, however, was correct). The check valves are two inch, Borg Warner, 1500 psi, Y-type, lift check valves and are spring loaded. The spring loading feature ensures that the valves will function as designed no matter what the installed orientation. Therefore, the fact that the valves were installed upside-down did not prevent them from performing their intended safety function. Rebuilding the check valves was effective in stopping back-leakage from the RWT to the NaOH tank. While work on the check valves was progressing, the NaOH tank was partially drained and refilled with concentrated NaOH to a level of 4058 gallons by local sight glass indication (minimum level by TS is 4010 gallons). The NaOH tank was declared back in service at 1:17 p.m. on February 17, 1986, before the 72 hour time limit imposed by the TS. The control room level indication was thought to be erroneous, because of a discrepancy between the sight glass and control room (remote) indication readings. The sight glass is a direct reading positive indicator whereas the remote level indicator is an electrical instrument composed of differential pressure transmitters and meters which are both susceptible to failures and miscalibrations. When the I&C personnel began work on the remote level indication for the NaOH tank, they found nothing wrong with the instrument loop. Further investigation revealed that the sight glass level indication was in error. The error was caused by the different fluid densities in the

sight glass and the bulk of the NaOH tank. When the NaOH tank was refilled, the sight glass retained a volume of much less concentrated NaOH. This reduced density caused the sight glass to read a higher level than actual tank level. After draining and refilling, the sight glass agreed with the remote indication of 3750 gallons. The NaOH tank was again placed out of service at 1:00 p.m. on February 19, 1986. By 5:15 p.m. that same day, level was restored to 4100 gallons and the system was returned to service.

Since the level indication used to return the NaOH tank to service on February 16 was inaccurate, the NaOH tank had not been properly restored to service. The NaOH tank was out of service for 128 hours instead of the 72 hours allowed by the TS. This is a violation of TS 3.6.2.2. After completing an in-depth review, the inspector determined that the licensee demonstrated the appropriate engineering judgement in believing that the local (sight glass) NaOH tank level indication was the actual tank level when compared to the remote level instrument in the control room. The unusual circumstance which resulted in an inaccurate local level reading would not normally be detected when making checks of a sight glass to ensure that the level indication was correct. Additionally, the licensee implemented appropriate and timely actions to resolve the discrepancy between the local and remote level indications which resulted in the final determination that the remote level instrument was, in fact, indicating correctly and the sight glass was not. In summary, in accordance with 10 CFR 2, Appendix C, IV.A, a Notice of Violation will not be issued.

9. Physical Protection (Units 1 and 2)

The inspectors verified by observation and interviews during the reporting interval that measures taken to assure the physical protection of the facility met current requirements. Areas inspected included the organization of the security force, the establishment and maintenance of gates, doors, and isolation zones in the proper conditions, access control and badging and adherence to procedures.

On April 9, 1986, while performing a routine plant tour, the resident inspector noted that access could be gained to the piping trenches which run underground to the Unit 1 condensate storage tank (CST). The inspector noted that one section of a metal grating, which covers the trench within the CST structure, was removed, permitting access to the trench. The CST is in a security area to which access is controlled with a locked door and card reader. On April 10, 1986, the inspector returned to the area outside the CST structure to complete his inspection. At this time, he noted that one concrete cover was removed from the top (ground level) of the piping trench outside of the CST area and access could be gained to the CST structure by way of the trench. The site security supervisor was notified of the potential security failure and he immediately dispatched a security officer

to the area. Subsequent investigation by the licensee revealed that a breach of the security area did exist and a guard was posted at the unauthorized opening. Until the NRC Region II security staff completes an inspection/review of this matter, this item is unresolved (50-335/86-07-02).

10. Surveillance Observations

During the inspection period, the inspectors verified plant operations in compliance with selected TS requirements. Typical of these were confirmation of compliance with the TS for reactor coolant chemistry, refueling water tank, containment pressure, control room ventilation, and ac and dc electrical sources. The inspectors verified that testing was performed in accordance with adequate procedures, test instrumentation was calibrated, LCOs were met, removal and restoration of the affected components were accomplished, test results met requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel. The inspectors observed all aspects of the following surveillances:

- 1-0700051, Rev. 0 — Auxiliary Feedwater Actuation System Monthly Functional Test, and
- 2-0010125, Rev. 16 — Schedule of Period Tests, Checks, and Calibrations (check sheet 1, April 1 - 8).

Portions of the following surveillance were also observed:

- 2-0010125, Rev. 16 — Schedule of Periodic Tests, Checks, and Calibrations (data sheet 3, monthly containment and shield building integrity check).

11. Preparations for Refueling - Unit 2

In preparation for the second refueling of Unit 2, several procedures were reviewed in order to assure technical adequacy and proper administrative control of refueling activities. The following areas were addressed:

a. Receipt, inspection, and storage of new fuel.

b. Fuel handling, transfer, and core verification.

c. Inspection of fuel to be reused; fuel assembly inspection using underwater video system.

d. Periodic monitoring of spent fuel pool cooling parameters and consideration of contingency cooling methods.

e. Fuel sipping operations.

f. Core and fuel bundle reconstitution.

g. Handling and inspection of other core internals.

In addressing the preceding areas, the following licensee procedures were reviewed:

Procedure No.	Rev.	Title
2-0110022	2	Coupling and Uncoupling of CEA Extension Shafts
2-1600022	1	Unit 2 Refueling Operations
2-1600023	6	Refueling Sequencing Guidelines
2-1610020	7	Receipt and Handling of New Fuel
2-1630021	3	New Fuel Elevator Operation
2-1630022	3	Spent Fuel Handling Machine Operation
2-1630023	1	Fuel Transfer System Operation
2-1630024	4	Refueling Machine Operation
2-1630025	0	CEA Change Fixture Operation
2-1630027	1	Dry Sipping of Irradiated Fuel Assemblies
2-1630028	6	New Fuel Handling Crane Operation
2-0010250	1	Guidelines for Use of the Unit 2 High Density Spent Fuel Racks
2-M-0036	5	Reactor Vessel Maintenance-Sequence of Operations
2-1240061	0	Installation and Removal of the Movable Incore System
2-1600030	2	Accidents Involving New or Spent Fuel
2-0350020	4	Fuel Pool Cooling and Purification System-Normal Operation
2-0350030	1	Fuel Pool Cooling System - Off Normal Operation
2-1110038	0	Off Normal Operation of the Fuel Building Effluent Monitor

All reviewed procedures were found to be technically accurate and properly controlled by plant management. This review has established licensee compliance with the TSs which require that written procedures be established covering refueling operations.

Along with the procedure reviews, the licensee's 10 CFR 50.59 safety evaluation for the cycle 3 reload was reviewed to ascertain whether an additional, more comprehensive NRC/NRR review may be required prior to reload. The conclusions of the report were that no TS changes would be required to implement the Unit 2 cycle 3 reload and no unresolved safety questions exist pertaining to the reload.

12. Refueling Activities - Unit 2

During primary side flood-up after installation of the steam generator nozzle dams, the licensee noted that there was a two gallon per minute leak past the 2A2 steam generator cold leg wet dam. The dams had been installed to permit eddy-current testing of the steam generator tubes while proceeding with refueling operations. At the close of this reporting period, the licensee was draining the reactor system to a level which would permit removal and repair of the faulty dam. Follow-up of refueling activities will continue during the next two reporting periods.