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

Report Nos.: 50-335/88-29 and 50-389/88-29

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: November 6 - December 10, 1988

Inspector: Bruce A. Wilson for 1/13/89
G. L. Paulk, Senior Resident Inspector Date Signed

Approved by: Bruce A Wilson for 1/13/89
R. V. Crlenjak, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This inspection involved on site activities in the areas of Technical Specification 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, and surveillance activities.

Results: Of the areas inspected, one inspector followup item was identified in the area of installed diesel instrumentation calibration requirements as noted paragraph 6.

The deficiencies noted in paragraphs 3a (Jumper/Lifted Lead Program), 3b (Quench Tank Rupture Event), 4a (Caution Tag Program Implementation), and 6 (Linear Power Range Calibration) would normally be noted as a violation. Due to current enforcement policy, these deficiencies will not be noted as a violation since corrective actions have been addressed prior to close of this report period.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

Barrow, J., Fire Prevention Coordinator
*Barrow, J., Operations Superintendent
*Boissy, G., Plant Manager
*Buchanan, H., Health Physics Supervisor
*Burton, C., Operations Supervisor
Dawson, R., Asst. Plant Superintendent - Electrical
Dillard, T., Maintenance Superintendent
*Frechette, R., Chemistry Supervisor
*Harper, J., QA Supervisor
*Harris, K., St. Lucie Site Vice President
*Leppla, C., I&C Supervisor
Roos, N., Quality Control Supervisor
Sculthorpe, B., Reliability and Support Supervisor
*Sipos, R., Service Manager
West, D., Technical Staff Supervisor
White, W., Security Supervisor
Wilson, C., Asst. Plant Superintendent - Mechanical
*Wunderlich, E., Reactor Engineering Supervisor

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

*Attended exit interview

2. Plant Tours (Units 1 and 2) (71707 and 71710)

The inspector conducted plant tours periodically during the inspection interval to verify that monitoring 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 controlled in accordance with procedures, excess equipment or material was stored properly, and combustible materials 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 setting, 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 frequency of plant tours and control room visits by site management was noted to be adequate.

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 inspector conducted a complete walkdown in the accessible areas of the plant to verify that system lineups were in accordance with licensee requirements for operability, and equipment material conditions were satisfactory.

During this reporting interval, the inspectors verified compliance with limiting conditions for operations (LCO's) 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 were reviewed on selected occurrences as they happened. The inspector verified plant procedures were adequate, complete, and the correct revision. Instrumentation and recorder traces were observed for abnormalities.

At the end of this reporting period, Unit 1 had operated continuously for 84 days and Unit 2 for 374 days.

3. Plant Operation Review (Units 1 and 2) (71707)

The inspector, 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 inspector routinely observed operator alertness and demeanor during plant tours. During routine operations, control room staffing, control room access and operator performance and response actions were observed and evaluated. The inspector conducted random off-hours inspection 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. Control room annunicators status was verified. The inspector performed an in-depth review of the following safety-related tagouts (clearances):

Unit 1

Clearance No.	Description
1-11-71	DEH Filters
1-11-68	1B1 Blowdown HEX
1-11-64	1B Boric Acid Concentrator

a. Jumper/Lifted Lead Program Review

During a routine inspection, the inspector observed a temporary 0-600 psi gauge installed on the Unit 1 low pressure heater system at PX 11-17A1 downstream of valve 2-V11926. A review of licensee records

revealed no traceability as to the use of this temporary gauge. A search by the licensee revealed that no work order or temporary alteration control form was used to track this temporary alteration. The licensee removed the gauge after notification by the inspector. The inspector expanded the scope of the inspection to look more generically at how the implementation phase of the Jumper Control System is working as described in Administrative Procedure 0010124. A review of the active jumper log in the control room revealed the following deficiencies:

(1) Records required for procedure implementation verification included the Change Review Team (CRT) documentation of the continued use review for jumpers. A request for the CRT meeting minutes data indicated that the required six month review documentation is not maintained and in fact is routinely thrown out after two years. The CRT documentation review of continued use for jumpers does not serve as a QA record; however, it does indicate management involvement in reviewing long-term jumpers for potential permanent design recommendation review process and does not verify program implementation. AP 0010124 should be clarified to state specifically the records retrieval periodicity of the CRT minutes.

(2) The clearance of jumpers and temporary alterations was inconsistent as noted on the jumper/lifted lead request log index sheets. Specifically, when a jumper is cleared the person removing the jumper is required to indicate the date removed and initial the log index sheet as required by step 8.10.3 of AP 0010124. Although the majority of the clearances were initialed correctly, many of the jumper removals were not initialed. A training review of AP 0010124 by all persons qualified to remove jumpers should assist in correcting this deficiency.

(3) A review of the active Control and Use of Jumpers and Disconnected Lead Requests for the jumper/lifted lead form (AP00101240) indicated inconsistencies in the Facility Review Group (FRG) approval process review documentation. An FRG approval, required prior to a Unit 1 jumper installation, was not signed by the Plant Manager (8-111). Several FRG approvals indicated a check where the Plant Manager signature should be (8-100, 8-101, 8-102). Most of the prior/past indications were not specific or marked. Some FRG reviews were indicated by the date of the FRG meeting and the FRG secretary initials. The inspector reviewed all the relevant FRG minutes and found them to indicate proper approvals. A more consistent FRG approval documentation process would be beneficial. Discussions with operators indicated uncertainty on what the different signoff methodologies meant or who was required to give the final approval signoff. The licensee committed to review this QA record documentation process and make changes as needed.

(4) No routine accountability audit is conducted to assure that the jumper/lifted lead tags originally hung on affected components are verified still in place. Accountability equipment audits are conducted for DANGER tags, (a similar system of control). This type of audit would assure positive control of temporary alterations in maintaining design interfaces of temporary alterations. The licensee committed to evaluate this concern.

During the above review process the following documents were reviewed:

(a) Unit 1 Jumper/Lifted Lead Logs
(b) Jumpers; 8-094, 8-100, 8-101, 8-102, 8-111, 8-117, 8-118
(c) QA Audits:

1) QSL-OPS-87-573 - Mode Changes and Plant Operating Status
2) QSL-OPS-88-601 - Tech Spec 3/4.5, Emergency Core Cooling Systems
3) QSL-OPS-88-616 - Performance Monitoring
4) QSL-OPS-87-528 - Inspection Test and Operating Status

(d) Procedures:

1) AP 0010124 - Jumper/Lifted Lead Procedure
2) 0005744 - Change Review Team Procedure (Non-QA)

Discussions held with plant management on the above concerns indicated that the inspector concerns will be expeditiously addressed. The inspector will follow up on the jumper/lifted lead program changes during future routine inspections.

b. Quench Tank Rupture Disc Event of November 1, 1988

(1) Background:

St. Lucie Unit 2 had been online for approximately eleven months prior to the event and two Quench tank related problems were being routinely dealt with by the Operations Department. First, a pressurizer code safety valve (there are three, with a lift setting of 2500 psia) was exhibiting a small amount of leakage into the Quench tank, requiring a routine cooling evolution to be performed approximately once per shift. During this cooling sequence, level in the Quench Tank is reduced by draining the contents to the Reactor Drain Tank and is replenished from the Primary Water System. This cooling evolution has been conducted once or twice per eight hour shift for the last several months. Verification that the leakage was not increasing over the cycle was ascertained through the calculation of RCS leak rates three times per week and the statistical trending of the Quench Tank cooling cycles per day.

The second problem being dealt with was the inability to supply a nitrogen purge to the Quench Tank through the nitrogen supply line due to a regulator malfunction. A long lead time was required to procure the necessary regulator parts. This problem was considered insignificant since nitrogen could be supplied to the Quench tank from another source; that being the Reactor Drain Tank purge system. To effect this lineup, the Reactor Drain Tank vent and the Quench Tank vent were simultaneously opened while the vent header isolation leaving containment was maintained closed. This effectively cross-tied the atmosphere of the two tanks.

(2) Event Chronology:

On November 1, 1988, Instrumentation and Control (I&C) technicians were installing a new Quench Tank level meter in the Unit 1 Control Room. The Reactor Operator at the controls was aware of the work. The Reactor Operator wanted to conduct an RCS Leak Rate determination and prior to data collection, wanted to cool the Quench Tank. The Level Meter for the Quench Tank was installed and operable when the cooling evolution was commenced; however, the high level alarm circuitry had not been reconnected. The Quench Tank normal operating procedure contains a section dealing with Quench Tank cooling but does not give specific guidance to ensure a consistent method for the drain and fill evolution. The Reactor Operator opened the drain valve to the Reactor Drain Tank and about six minutes later opened the fill valve to the Quench Tank after reaching a level that he did not wish to go below (45%). With the fill valve and drain valve simultaneously open he knew, and observed, that level in the Quench Tank would rise very slowly. Seven minutes later the Reactor Operator closed the drain valve, having cycled enough water through the tank to effect cooling. At this time the level was 49%. With the drain valve closed the tank filled more rapidly (112 gallons per minute).

At 1000 hours, the Reactor Operator had to leave the immediate control panel area of the Quench Tank controls to take electrical integrator readings. Before leaving the controls, he verified the level in the tank was below the high alarm setpoint. When he returned from the other section of the control board, (3 minutes later), he admittedly had lost track of the evolution with the Quench Tank. In this instance, the high level alarm for the new Quench Tank level meter did not function due to maintenance. The proper circuitry connections for the high level alarm on the new level meter had not been completed; however, the operator had assumed the installation was fully complete. The Quench Tank high pressure alarm was never received. Recorded traces of the event indicated that Quench Tank pressure never exceed 7 psig.

Several minutes after the high level alarm should have sounded, alarms were received indicating a problem with pressurizer level and the pressurizer code safety valves. The operators scanned their instruments and quickly realized that the Quench Tank level indicated full with pressure in the Quench Tank dropping to zero psig. The reactor cavity sump leakage recorder alarmed momentarily, indicating inleakge. Total leakage was estimated to be less than 20 gallons with the fluid being primary water, not reactor coolant. The operators on shift assumed the rupture disk had failed and notified Health Physics personnel to prepare for a containment entry for verification. The entry revealed that the Quench Tank rupture disk (85 psig setpoint) had failed. It was also noted that the installed relief valve on the tank was not gagged or otherwise prohibited from functioning. This relief is set to lift at 70 psig. It was not able to be determined if this relief valve lifted, or even if a true high Quench Tank pressure was ever achieved. It is the opinion of the Mechanical Maintenance Department Head that the daily cycling of the Quench Tank contents may have sufficiently fatigued the rupture disk so that when the water reached it and pressure started rising, it simply failed prematurely.

(3) Licensee Actions:

(a) Counseling of the involved Reactor Operator, his crew and the entire Operations Department was conducted either privately or through the publication of a night order reminding people that seemingly routine, low impact evolutions can and do result in more serious situations.

(b) The Quench Tank operating procedure is being enhanced to reflect current operation philosophy in regard to cooling evolutions and the need to review/use procedures even for routine evolutions was re-emphasized.

(c) Engineering has been asked to review the relieving adequacy of the Quench Tank relief valve for an overfill event.

(d) The pressurizer code safety valves had already been targeted for maintenance during the upcoming refueling outage.

(e) The Quench Tank rupture disk will be routinely changed out during refuelings to reduce the possibility of fatigue failure.

(f) The Quench Tank relief valve setting will be verified during the upcoming refueling outage.

(g) The licensee will investigate why the Unit 1 high pressure alarm for the Quench Tank is set at 10 psig; whereas, Unit 2 is set at 25 psig.

The inspector closely monitored the activities and followup of this event. The inspector will followup on the above corrective actions during future routine inspections.

4. Maintenance Observation (62703)

Station maintenance activities of 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; limiting conditions for operations 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 status of outstanding jobs and to assure the priority was assigned to safety-related equipment. The inspectors observed portions of the following maintenance activities:

Unit 2 fire protection system preservations work,

Unit 2 new fuel handling,

Unit 1 circulating water pump maintenance, and

Unit 1 fire protection system alarm circuitry maintenance.

a. Caution Tag Procedure Review

The inspector reviewed the Caution Tag Clearance Procedure for the facility as implemented by Administrative Procedure 0010135. The caution tag procedure specifies two systematic approaches to CAUTION TAG issuance/removal and control. One system includes operational caution tags controlled by the Nuclear Watch Engineer, Assistant Nuclear Plant Supervisor or Nuclear Plant Supervisor (NPS) and the other system is controlled by the Electrical Department specifically for the placement of caution tags on equipment grounding devices. The two systems are controlled for the facility by Administrative Procedure 0010135. At the conclusion of the inspection, the inspector noted the following weaknesses in program control that should be improved to prevent potential safety system inoperability:

(1) The two systems which control caution tag issuance and removal are non-communicative such that the NPS is not aware of caution tags issued by the electrical department. The potential exists for a grounding strap to be placed on a safety related system required for plant operability without NPS knowledge or control.

(2) The index of operational caution tags is only maintained in the control room; whereas, the electrical department caution tag index is maintained only in the electrical department.

(3) The caution tag procedure does not require any type of routine audit or verification of caution tag status in the field. (The danger tag system does require an audit function.) Some caution tags were issued in the 1984/85 timeframe.

(4) Caution tags which remain in force for more than one month are required by step 7.3 of the implementing procedure to be statused and reported to the operations supervisor. Discussions with the operations supervisor indicated that the status of electrical department caution tags is not routinely discussed with operations.

(5) The caution tag itself is not adequately human engineered for proper usage. All tags issued require additional write-in blocks added by the person using the tag to state "tag #____ and Location ____" requirements. The caution tag is a generic Florida Power and Light Company tag used at various types of facilities. The general description on the tag may be appropriate at a less controlled facility, however, to assist operator and maintenance personnel, it would be advantageous to re-format the caution tag data to be more human factors oriented.

b. Confined Workplace Entry Program

The inspector reviewed the licensee's program established to meet the minimum requirements to ensure that safe measures and precautions are incorporated and accomplished prior to personnel entry into confined work spaces. Administrative Procedure 0010505 implements the programmatic requirements related to licensee personnel only. Contractor personnel are controlled by the respective contractor industrial safety manual. The two programs do not communicate with each other and share no common management controls.

During a tour on December 6, 1988, the inspector observed an open underground pipe/cable chase near the Unit 2 diesel building with a contractor confined space entry permit tag posted without the safety officer verification signature and four days out-of-date. The entry permit is required to be updated each shift of work progress. This specific permit was dated December 2, 1988. Discussions with the licensee safety officer revealed a lack of full awareness of how the contractor confined space entry program works. Followup discussions revealed that the contractor program had been changed at some time in the past, deleting the requirement for the safety officer verification signature. Also, the permit being used (and observed by the inspector) was actually the wrong type permit since a new permit

was previously issued by the contractor. No procedure or instruction was available for inspector review which describes how the contractor controls its program.

The inspector reviewed the overall licensee and contractor programs further and noted the following deficiencies:

(1) Contractor controls for the confined work space entry program used within the site were inadequate, with minimal controls for program implementation or verification.

(2) No traceability of confined space work activities ongoing or completed could be determined as not one person onsite knew what was scheduled. No index or controls existed to determine confined space activities. Each department foreman is responsible for work his staff performs or each contractor foreman is responsible for his work activities. The licensee safety officer maintains no controls over either of these evolutions.

(3) Failure to communicate between licensee and contractor safety officers on work activities could potentially jeopardize plant or personnel safety.

This overall program should be evaluated by licensee management to ensure satisfaction with program implementation.

5. Physical Protection (Units 1 and 2) (71881)

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, that access control and badging was proper, and procedures were followed.

6. Surveillance Observations (61726)

During the inspection period, the inspectors verified plant operations in compliance with selected technical specifications (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, limiting conditions for operations 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 and/or reviewed the following surveillances:

a. I&C Procedure 1-1220052; Unit 1 Nuclear Instrumentation Monthly Calibration

b. Operating Procedure 1-2200050; Unit 1 Diesel Generator Periodic Test

The resident inspector observed the annual fire emergency drill on December 7, 1988. The drill involved the response of local city fire department personnel in conjunction with the plant fire brigade. The annual drill is used by the licensee to evaluate; the response of offsite emergency personnel, plant access control to the affected site area, verification of the agreement of mutual understanding for response between local emergency organizations and the licensee, and the overall coordination in combating the casualty by site and offsite personnel. The fire brigade responded to the fire scene with proper equipment within seven minutes of the fire alarm with offsite emergency personnel responding within 10 minutes of being notified. The drill was considered successful by the licensee and offsite personnel alike. The inspector identified no significant deficiencies.

During the observation of I&C Procedure Number 1-1220052, Unit 1 Linear Power Range Safety and Control Channel Monthly Calibration, the inspector noted several deficiencies that should be addressed by the licensee as noted below:

a. The tolerance value of ± 3 millivolts specified throughout the procedure for channel operating voltage settings cannot be met. Channel operating voltage fluctuations were observed in the tenths of volts. The craft and appropriate management personnel were aware of this difference; however, no procedural change or appropriate discussions with the nuclear instrumentation supplier have occurred to see if the tolerance band can be relaxed. The tolerance band was originally specified by the vendor.

b. Several procedural steps were out-of-order and if the procedure was used precisely on one occasion a potential plant perturbation could occur. The craft personnel were aware of these procedural step deficiencies and worked around them due to their knowledge of system operation.

(1) Step 2 of procedure section 9.1 states that for the control cabinets; in the Power Ratio Calculator, place the toggle switch for the channel under test in the OUT position. A note following this step refers the technician running the surveillance to a step in the precaution section of the main procedure which states that the technician must ensure the reactor regulating system is not selected to the channel being calibrated. Failure to correctly do this note could lead to significant plant perturbations. The craft and management responsible for this procedure realized this could occur. The step should be written as a CAUTION statement prior to this step

to assure the proper order of conduct for other craft not fully aware of this step significance.

(2) The technician conducting the procedure is required, as a first step, to verify that 15% Low Power Feedwater Control Valves LCV-9005 and LCV-9006 are in manual. In the actual procedure format this step is noted after procedural step 2 section 9.1. The procedure should reflect actual procedure conduct and order.

(3) Step 9.22 should directly follow step 9.19 since 9.22 is the criteria for success recorded in step 9.19. Failure to have these steps near each other in the procedure led to confusion on what step 9.22 was trying to prove.

c. During the calibration of the "C" safety channel, the inspector noted that the Loss of Load trip alarm initiated. This alarm did not initiate during the calibration of the A, B, or D safety channels. Neither the technicians or appropriate management on the scene could explain why this occurred. This phenomenon should be evaluated for potential "C" channel problems. The procedure does not require abnormalities to be checked when not required by the procedure signoffs; however, the inspector expects common engineering judgement to prevail and abnormalities be noted and corrected.

The inspector had several management meetings with appropriate management and corrective actions were taken to address the above concerns. Routine inspection followup will be scheduled.

The inspector observed the performance of surveillance 1-2200050 (revision 42), Emergency Diesel Periodic Test, for the "1A" diesels. The test went smoothly with only minor discrepancies. At the point where the "1A" diesels had just been started, an operator failed to start a stop watch as required by the procedure and the diesels were stopped. The test was re-initiated at the diesel start step in the procedure (section 8.1.17) within one and one-half hours of halting the test. No reverification of previous steps were made prior to the diesel start step; the unit operator who had left the diesel cubicle briefly looked over the diesel cubicle prior to restart. The remainder of the test went without incident. The system engineer who was present for the test submitted eight work requests on minor problems with the diesels such as fitting leaks.

The inspector determined that a number of local temperature gages used during the test as equipment status indicators were not in calibration program. Other compliance related gauges are in a calibration program. Lubrication oil and cooling water (LO & CW) gauge data was taken during the test on a form that indicated minimum/maximum figures used as guidelines only and do not represent acceptance criteria; the system engineer does use the LO & CW data to trend overall unit performance. Thermocouples used in a pyrometer arrangement to take diesel cylinder exhaust temperatures were not in a calibration program; the meter

thermocouple system could be tested together but are only operationally checked during use. The system engineer utilizes the readings to indicate failed cylinder valves, (ie., a dead cylinder whose temperature would be significantly less than the other cylinders). The thermocouple system used in that manner (on or off), would not necessarily require calibration. With the precautions and limitations section of the test procedure (section 4.8) two temperature instruments are addressed; these instruments may be in a calibration program. The inspector will review the use and calibration status of the above instrumentation in the future. The licensee committed to review diesel instruments that should be covered by a calibration program. Until this review can be accomplished, this issue will remain an inspector followup item, Inplant Diesel Instrumentation, 50-335, 389/88-29-01.

7. Exit Interview (30703)

The inspection scope and results were summarized on December 16, 1988, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed above. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description
50-335,389/88-29-01	IFI - Inplant Diesel Instrumentation Calibration (paragraph 6)