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

Report Nos: 50-335/90-30 AND 50-389/90-30

Licensee: Florida Power & Light Co
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 20 - December 17, 1990

Inspectors: for S. A. Elrod, Senior Resident Inspector — 1/9/91 Date Signed

for M. A. Scott, Resident Inspector — 1/9/91 Date Signed

Approved By: R. V. Crlenjak, Section Chief, Division of Reactor Projects — 1/9/91 Date Signed

SUMMARY

Scope:

This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, and surveillance observations.

Results:

No violations or deviations were identified. Several problems occurred during the Unit 2 outage that delayed the unit's return to service; these are discussed in paragraph 3. One of the Unit 2 problems was resolved in part via an NRC granted waiver of compliance regarding the 2B component cooling water heat exchanger. On December 4, the 1A condensate pump began to have visible vibration problems requiring a slow, well-controlled power reduction. Operations were generally very conservative during this period.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Sager, St. Lucie Site Vice President
G. Boissy, Plant Manager
* J. Barrow, Operations Superintendent
J. Barrow, Fire Prevention Coordinator
R. Church, Independent Safety Engineering Group Chairman
* H. Buchanan, Health Physics Supervisor
C. Burton, Operations Supervisor
D. Culpepper, Site Juno Engineering Supervisor
R. Dawson, Maintenance Superintendent
* J. Dyer, Quality Control Supervisor
* R. Englmeier, Quality Assurance Superintendent
R. Frechette, Chemistry Supervisor
* C. Leppla, I&C Supervisor
L. McLaughlin, Plant licensing Superintendent
L. Rogers, Electrical Maintenance Supervisor
N. Roos, Services Manager
D. West, Technical Staff Supervisor
J. West, Mechanical Maintenance Supervisor
W. White, Security Supervisor
* G. Wood, Reliability and Support Supervisor
* E. Wunderlich, Reactor Engineering Supervisor

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

NRC Employees

* S. Elrod, Senior Resident Inspector
* M. Scott, Resident Inspector

* Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Site Activities

Unit 1 began and ended the inspection period at power - day 48 of power operation. Unit 1 reduced power on December 4 to swap from 1A to 1C condensate pump due to excessive 1A pump shaft vibration.

Unit 2 began the inspection period in day 51 of a maintenance and refueling outage. The reactor was taken critical on November 28 and low power physics testing was conducted. The unit was shut down on

November 30 to repair a 2A1 SIT relief valve and was restarted on December 2. On December 5, outage day 66, following one tentative start of the main turbine generator, its output breaker was closed for the second time - completing the outage. Unit 2 ended the period in day 11 of power operation.

3. Review of Plant Operations (71707)

a. Plant Tours

The inspectors periodically conducted plant tours 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 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 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 frequency of plant tours and control room visits by site management was noted to be adequate.

The inspectors routinely conducted partial walkdowns of ESF, ECCS, and support systems. Valve, breaker, and switch lineups and equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory: Unit 2 Containment, Unit 2 spent fuel pool and support equipment rooms, Unit 2 CCW heat exchanger 2B, Unit 1 and 2 ECCS spaces, and Unit 1 and 2 AFW pump rooms.

b. Plant Operations Review

The inspectors periodically 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. They observed and evaluated control room staffing, control room access, and operator performance during routine operations. The inspectors conducted random off-hours inspections to assure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. Except as noted below, no deficiencies were observed.

During this inspection period, the inspectors reviewed the following tagouts (clearances):

1-11-78 1B HPSI pump,

1-11-79 1B LPSI pump,

2-10-22 2A Spray pump discharge isolation valve, V7145, and

2-11-216 Unit 2 MSIV control air valves.

The Unit 2 outage end date slid from the November 25 target to December 2 for resolution of the following critical path problems:

2B CCW HX casing-to-tube-sheet weld leaks,

Leaking 2A1 SIT relief valve,

Water found in the main turbine lubricating oil,

RCS leakage into the pressurizer relief quench tank,

A main turbine lubricating oil leak and steam bypass control valve operational difficulties, and

Suspected main turbine rubbing.

The weld repair of the casing-to-tube-sheet West end bimetallic weld on the 2B CCW HX was completed and hydrostatically tested on November 15. Its later-than-desired completion date delayed the return to service of the "B" train CCW/ICW systems and the critical systems that they support. This repair was discussed in IR 335,389/90-28 paragraph 5 and is further discussed in paragraph 5 below.

Subsequently, the 2B CCW HX East end casing-to-tube-sheet bimetallic weld developed a leak requiring repair (also discussed in paragraph 5 below). Its hydrostatic test was accepted on November 26.

Based on finding the second weld defect in the 2B CCW HX, the licensee requested a NRC temporary waiver of compliance to allow ascension to Mode 2 without the "B" train of ICW/CCW in operation. The request, detailed in FPL letter L-90-413, dated November 23, asked for a 5 day waiver, allowing operational checks of other systems and components while the HX repair proceeded. The request was verbally granted on November 23 and a confirming NRC letter was issued on November 26.

The licensee entered into the allowances of the above waiver at 5:00 p.m. on November 23 and completed repairs to the CCW HX at 6:00 a.m. on November 25 while in Mode 3. While under the conditions of the waiver, no TS LCOs were entered nor additional safety-related equipment taken out of service. This completes the implementation of this waiver of compliance.

Upon pressurizing the RCS and the SITs on November 27, the 2A1 SIT relief developed a slight nitrogen leak at the valve seat at pressure. The valve was replaced twice and was ultimately accepted on December 2.

During low power physics tests on November 28, the reactor engineering group observed a negative power anomaly, a 70 PCM drop in reactor power, which could not be immediately explained. It was resolved after one and a half days of investigation.

While in the vicinity of 0.001 percent power and performing low power physics testing in accordance with OP 0110052, Rev 10, Zero Power Physics Tests After Reload, the operations and reactor engineering staffs saw an apparent negative power anomaly, a 70 PCM power drop as seen on their power recorder, that could not be explained at the time. The reactor had been in a highly controlled and monitored state at the time that the anomaly had been noticed. Shutdown group B was stepwise being manually driven into the the core (29 to 22 inches above the LEL) while a constant dilution was occurring when the anomaly was detected on a reactor monitor/ recorder setup. The phase of testing was halted and the licensee began to investigate the possibly of a dropped CEA and/or a detached CEA.

As the additional investigative CEA testing and review of the data surrounding the happening proceeded, it was discovered that the operator had driven in the group when he thought he had driven an individual CEA for group height adjustment. The driving of the group of CEAs approximately two inches made it appear as though a single CEA of the group had dropped the remaining 22 inches to the bottom of the core (an approximate equivalent negative reactivity worth of the group downward motion). The inspector reviewed the computer data on the anomaly and agreed with the conclusions drawn. The data supported the fact of the minor operator error during the testing. The licensee's evaluation was thorough and complete, and they were considering a number of possible corrective actions.

On November 30, during bearing lubricating pump testing, excessive water was found in the turbine lubricating oil (4.8 percent concentration when the acceptable limit was 0.1 percent). On November 21, auxiliary steam had been brought from Unit 1 to Unit 2 to support preliminary turbine equipment testing. The water entered the oil from auxiliary steam being provided to the turbine's gland seals without the gland seal exhauster in service and with the lubricating oil vapor extractor in service. By December 1, the oil was replaced with fresh oil obtained from the Turkey Point plant.

On December 1, approximately 0.4 gpm quench tank inleakage was identified. The TS limit for identified leakage is 10 gpm. The

licensee spent over a day collecting and analyzing available data. The leakage was thought to be from the reactor gas vent system and/or a pressurizer safety valve. No further licensee action was deemed prudent.

On December 2, after the reactor had been taken critical the second time, the licensee had difficultly putting the main turbine generator on line due to an oil leak at the number 2 turbine bearing, and due to the five percent steam bypass valve, PCV 8801, not controlling properly. The leak was repaired, the valve was troubleshot (see paragraph 5 below), and the generator was brought on line the afternoon of December 3.

On December 4, the licensee performed the main turbine overspeed trip test. The test was performed after a minimum of ten hours on line and at 25 percent power. During the subsequent coastdown, rubbing was thought to have been noted and the roll down time was thought to have been less than normal.

The reactor remained critical as the licensee investigated for potential problems. The licensee took one complete day to evaluate turbine data and pull inspection covers. The licensee concluded that the noise was unaccounted for and that it was probably not a real problem. The turbine was rolled to 550 rpm on December 5 with no problems; the coast down from this speed was normal. The turbine breaker was latched a second time since the reactor had been critical. By midday the plant was up to to 30 percent power and holding to establish secondary chemistry conditions for power operations with no extraneous problems.

The Unit 2 reactor was taken critical a second time on December 2. The applicable procedures were as follows:

OP 0030126, Rev 11, Estimated Critical Conditions and Inverse Count Rate Ratio,

OP 2-0030122, Rev 26, Reactor Startup, and

OP 2-0030221, Rev 12, Unit 2 Initial Criticality Following Refueling.

The core had been loaded this outage with low leakage fuel and this fuel load arrangement had a slightly positive MTC (3.8 PCM per degree F). Taking the reactor critical was very controlled with a reactor engineer, STA, and an additional SRO supporting the operations activity. The extra SRO was acting as reactivity manager during the evolution. Criticality was reached at 4:48 p.m. on November 2 with the critical position within the allowable tolerance band. There was minimal overshoot of the ECC position and the reactor was very stable at low power.

On December 3 after some minor problems which were indicated above (turbine lubricating water contamination, quench tank in-leakage investigation, etc.), the main turbine generator was rolled at 1:10 p.m. with no major difficulties. The applicable procedure was OP 2-0030124, Rev 40, Turbine Startup - Zero to Full Load. The turbine valve trip test was performed without problems at 550 rpm. The turbine was then relatched and speed increased. The turbine exhibited no noticeable vibration and the generator output breaker was closed at 2:43 p.m. with reactor power at approximately 11 percent.

On December 4, the 1A condensate pump/motor developed heavy vibration. The coupled shafts of the pump and motor were visibly moving in a radial direction. Within a short period on the same day, Unit 1 was down powered to 40 percent power so that failure of the 1A pump would not trip the plant and then the pump was secured.

Unit 1 has a spare 1C condensate pump and motor. Each of the three condensate pumps have a 50 percent plant capacity. Forty percent plant output would allow margin within which to maneuver the plant while realigning from the 1A pump to the spare 1C pump. At 40 percent power level and after the 1A pump had been stopped, the 1C condensate pump could be started. Prior to starting the 1C pump, it had to be connected electrically to the supply shared with the 1A motor.

For the sake of operational focus, Unit 1 was held at 40 percent until December 5 when Unit 2 was stable and holding at 30 percent power. The transfer from 1A to 1C condensate pump on December 5 was successful and Unit 1 resumed full power operation on December 6. Preliminary analysis indicated that 1A failure was caused by lower motor bearing failure for reasons not yet clearly identified.

c. Technical Specification Compliance

Licensee compliance with selected TS LCOs was verified. This included the review of selected surveillance test results. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, and switch positions, and by review of completed logs and records. Instrumentation and recorder traces were observed for abnormalities. The licensee's compliance with LCO action statements was reviewed on selected occurrences as they happened. The inspectors verified that related plant procedures in use were adequate, complete, and included the most recent revisions.

d. Physical Protection

The inspectors verified by observation during routine activities that security program plans were being implemented as evidenced by: proper display of picture badges; searching of packages and personnel at the plant entrance; and vital area portals being locked and alarmed.

Operations during this period were controlled and conservative.

4. Surveillance Observations (61726)

Various plant operations were verified to comply with selected TS requirements. Typical of these were confirmation of TS compliance for reactor coolant chemistry, RWT conditions, 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 properly, 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 following surveillance tests were observed:

AP 2-0010125A, Rev 20, Surveillance Data Sheets, Data Sheet 25, was satisfactorily completed for the Unit 2 hot leg injection header check valves V3524 and V3526. The surveillance tested the valves for backleakage from the RCS toward the RAB ECCS equipment.

OP 2-0810050, Rev 14, Main Steam/Main Feedwater Isolation Valve Periodic Test, was satisfactorily completed for the fast closure testing of the two MSIVs and the four MFIVs on Unit 2. The six valves were simultaneously closed with an injected MSIS signal.

OP 2-0410050, Rev 17, HPSI/LPSI Periodic Test, was satisfactorily completed on the 2A HPSI pump following extensive troubleshooting of the motor over a five week period. Paragraph 4 of IR 335,389/90-28 discussed the motor work in progress.

OP 2-0420050, Rev 22, Containment Spray and Iodine Removal System - Periodic Test, was satisfactorily completed on the 2A containment spray pump. IR 335,389/90-24 (paragraph 2.b.) discussed ECCS check valve slam problem correction efforts. The pump was started without any previously associated check valve slam due to operations staff preparation. The non-licensed operators involved with the test demonstrated good ALARA preparations before and during pump testing.

OP 2-0700050, Rev 21, Auxiliary Feedwater Periodic Test, satisfactorily tested the 2C AFW pump. The steam turbine driven pump smoothly came up to speed and the speed remained constant throughout the test. Pump data indicated that the pump was acceptable for pending operational mode changes.

Prior to the test, the handwheel of MV 08-03, the pump's trip and throttle valve, was found unlocked. The operator conducting the test recognized the status as being other than normal and brought it to the attention of the control room. This is an example of the turbine operator maintaining a questioning attitude. Unknown to the operator, the valve status had been properly changed to being unlocked. The status of the hand wheel lock had been previously entered in the control room's locked valve deviation log. The valve handwheel lock status did not affect normal valve function.

The surveillances observed were professionally performed and operational review was adequate.

5. Maintenance Observation (62703)

Station maintenance activities involving 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. Portions of the following maintenance activities were observed:

Work process sheets 5033 and 8740 as well as NPWO 5708/90 controlled 2B CCW HX repairs discussed in paragraph 6 below.

NPWO 7834/62 controlled work on Unit 2 steam bypass valves PCV 8802 and PCV 8803, while NPWO 7819/62 controlled work on PCV 8801. During initial turbine roll, the bypass valves were contributing to operational problems that caused the licensee to defer steam turbine operation. The 8802 and 8803 valves can bypass to the condenser 10 percent of the SG output steam flow, while the 8801 valve will bypass 5 percent of the SG output. The initial work on the 10 percent valves indicated that valve control was adequate. Valve 8801 was jittery around 50 to 75 percent open for unknown reasons. Continued use of the 8801 valve smoothed out its operation sufficiently to be acceptable to the operations staff for turbine roll. The valve controlled SG pressure well during the turbine restart.

Maintenance department observations of valve 8801 operation led to the suspicion that the valve's plug had been marred, causing undue resistance to valve operation. The observations were made by several disciplines with excellent interaction. A new NPWO was written to inspect the valve's internals during a future outage.

The overall maintenance effort was consistently well controlled.

6. Outage Activities (62703)

The inspector observed the following overhaul activity during the ongoing Unit 2 outage:

Paragraph 3 above and paragraph 5 of IR 335,389/90-28 discussed repair and initial hydrostatic testing of the 2B CCW HX. The initial test indicated a pinhole leak in the West end casing-to-tube-sheet bimetallic weld. The weld was shown on Yuba Heat Transfer Division drawing 75-N-013-1A-1AB. The licensee called in the HX vendor and another contractor to evaluate this potential generic issue. Corporate engineering took a "boat" sample of the weld area that included the weld defect for analysis at the corporate lab. The licensee generated the "evaluation of 2B CCW heat exchanger tube sheet/shell weld" (JPN-SPSL-90-2226) against NCR 2-428 to explain the mechanics of the weld problem and detail the intended weld repair.

The root cause of the evaluation indicated that a lack of fusion between the weld material and carbon steel of the shell of the HX had resulted in sufficient voiding in the weld to allow for the observed leakage. The root cause of the weld defect has been determined to be a fabricating defect, as proven by lab results. The stress induced due to retubing of the 2B HX, including the removal and reinstallation of the channel heads, as well as the subsequent hydrostatic testing was the reason for the small leak indicated. The HXs on unit one were of a different weld configuration. The 2A HX was not retubed to date.

The maintenance staff repaired the west end weld joint, 17 inches of total reweld, and hydrostatically retested the joint (ASME Section IX inspection report number M90-4402). There were some site internal problems indicated on welder qualification which were ironed out between the engineering staff and the ANII as described in NCR 2-435. The site QC staff was present through all stages of the weld repair.

The above testing induced or was a factor in the occurrence of a second weeping leak in the tube sheet bimetallic weld on the east end of the same 2B HX. Corporate engineering generated a revision to the above evaluation, JPN-SPSL-90-2226, against a new NCR (2-434) for the new defect prior to submitting the waiver request to the NRC discussed in paragraph 2 above. The replaced weld length in the area of this defect was 27 inches.

After the weld repair of the east end weld, the HX was subjected to a third hydrostatic test (ASME Section IX inspection report number M90-4427) which the bimetallic joint passed. Both bimetallic welds were examined visually at hydrostatic test pressure for signs of leakage and none were in evidence. The licensee has stated that the weld issue will be revisited at the next outage. The NRC plans to review the technical aspects of the overall HX problem, identified as IFI 335,389/90-30-01, Followup on 2B CCW HX Bimetallic Welds.

During the latter stages of the Unit 2 outage, with the reactor in Mode 3 and system pressure at 1600 psig, a reactor gas vent system one inch

outside diameter pipe developed a through-wall leak. The leak was identified during a normal operations staff walk down of pressurized piping and was isolable. The pinhole leak was mid-span in a straight run (approximately 24 inches) of pipe; not near a weld joint or a bend. Steam had been seen blowing out of the lagging surrounding the pipe. The piping was upstream of the pressurizer side of valve V1460 as seen in drawing 2998-G-078, sheet 107. The section of pipe was removed for destructive analysis by the corporate engineering staff. NPWO 3414/62 and NCR 2-437 controlled the replacement and root cause determination. Results indicated that the cause for the leak was chloride induced stress corrosion cracking. The NCR stated that chlorides were thought to have gotten on the pipe during original construction and this occurrence was an isolated event.

The above problems were expected during the life of the plant and were properly identified by the licensee.

7. Exit Interview (30703)

The inspection scope and findings were summarized on December 20, 1990, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
389/90-30-01	open	IFI - Followup on 2B CCW HX Bimetallic Welds, paragraph 6.

8. Abbreviations, Acronyms, and Initialisms

ACRS	Advisory Committee on Reactor Safety
AFW	Auxiliary Feedwater (system)
ALARA	As Low as Reasonably Achievable (radiation exposure)
ANII	Authorized Nuclear Inservice Inspector
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ATTN	Attention
CCW	Component Cooling Water
CEA	Control Element Assembly
CFR	Code of Federal Regulations
DPR	Demonstration Power Reactor (A type of operating license)
ECC	Estimated Critical Condition
ECCS	Emergency Core Cooling System
ESF	Engineered Safety Feature
gpm	Gallon(s) Per Minute (flow rate)
HPSI	High Pressure Safety Injection (system)
HX	Heat Exchanger

I&C	Instrumentation and Control
ICW	Intake Cooling Water
IFI	[NRC] Inspector Followup Item
IR	[NRC] Inspection Report
LCO	TS Limiting Condition for Operation
LEL	Lower Electrical Limit
LPSI	Low Pressure Safety Injection (system)
MFIV	Main Feed Isolation Valve
MSIS	Main Steam Isolation Signal
MSIV	Main Steam Isolation Valve
MTC	Moderator Temperature Coefficient
MV	Motorized Valve
NCR	Non Conformance Report
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
OP	Operating Procedure
PCM	PerCent Milli (0.00001)
PCV	Pressure Control Valve
psig	Pounds per square inch (gage)
RAB	Reactor Auxiliary Building
RCS	Reactor Coolant System
Rev	Revision
rpm	Revolutions per Minute
RWT	Refueling Water Tank
SG	Steam Generator
SIT	Safety Injection Tank
SRO	Senior Reactor [licensed] Operator
SSER	Supplemental Safety Evaluation Report
STA	Shift Technical Advisor
TS	Technical Specification(s)