SLSR1094.WP

REGION II

ATLANTA, GEORGIA

PLANT STATUS REPORT

ST. LUCIE

OCTOBER, 1994

PF/39

PLANT STATUS REPORT FOR ST. LUCIE (10/94)

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PART 1 - FACILITY DESCRIPTION

1.1 FACILITY/LICENSEE

FACILITY: St. Lucie Units 1 and 2
PLANT LOCATION: Hutchinson Island near Port St. Lucie, Florida
LICENSEE: Florida Power and Light Co. (Corporate Office in Juno Beach, Florida)

1.2 UTILITY SENIOR MANAGEMENT

CORPORATE:

J. L. Broadhead (Jim), Chairman of the Board and CEO
J. H. Goldberg (Jerry), President, Nuclear Division

SITE:

D. A. Sager (Dave) - St. Lucie Plant Vice President
C. L. Burton (Chris) - Plant General Manager
L. W. Bladow (Wes) - Nuclear Assurance Manager
H. F. Buchanan (Hank) - Health Physics Supervisor
R. L. Dawson (Bob) - Licensing Manager
D. J. Denver (Dan) - Site Engineering Manager
H. L. Fagley (Herman) - Construction Services Manager
P. L. Fincher (Pat) - Training Manager
R. J. Frechette (Bob) - Chemistry Supervisor
J. Marchese (Joe) - Maintenance Manager
W. L. Parks (Bill) - Reactor Engineering Supervisor
C. A. Pell (Ash) - Outage Manager
J. Scarola (Jim) - Operations Manager
J. A. West (Jeff) - Services Manager
D. H. West (Dan) - Technical Manager
C. H. Wood (Chuck) - Operations Supervisor

1.3 NRC STAFF

REGION II, Atlanta, GA:

S. D. Ebneter (Stew), Regional Administrator, (404) 331-5500
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D. M. Verrelli (Dave), Branch Chief, (404) 331-5535
K. D. Landis (Kerry), Section Chief, (404) 331-5509
R. P. Schin (Bob), Project Engineer, (404) 331-5561
A. R. Long (Becky), Project Engineer, (404) 331-4664

SITE:

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M. S. Miller (Mark), Resident Inspector, (407) 464-7822

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S. A. Varga (Steven), Director, Division of Reactor Projects-I/II, (301) 504-1403
J. A. Zwolinsky (John), Deputy Director, Division of Reactor Projects-I/II, (301) 504-1335
V. M. McCree (Victor), Acting Director, Project Directorate II-2, (301) 504-1485 [90 DAY DETAIL]
J. A. Norris (Jan), Senior Project Manager, Project Directorate II-2, (301) 504-1483

AEOD:

S. Israel (Sandy), Reactor Operations Analysis Branch, (301) 415-7573

1.4 LICENSE INFORMATION

	Unit 1	Unit 2
Docket Nos.	50-335	50-389
License Nos.	DPR-67	NPF-16
Construction Permit Nos.	CPPR-74	CPPR-144
Construction Permit Issued	7/1/70	5/2/77
Low Power License	NA	4/83
Full Power License	3/1/76	6/10/83
Initial Criticality	4/22/76	6/2/83
1st Online	5/17/76	6/13/83
Commercial Operation	12/21/76	8/8/83

1.5 PLANT CHARACTERISTICS

Description	Units 1 and 2
Reactor Type	Combustion Engineering PWR, 2-loop
Containment Type	Freestanding Steel w/Shield Building
Power Level	830 MWe (2700 MWt)
Architect/Engineer	Ebasco
NSSS Vendor	Combustion Engineering
Constructor	Ebasco
Turbine Supplier	Westinghouse
Condenser Cooling Method	Once Through
Condenser Cooling Water	Seawater

1.6 SIGNIFICANT DESIGN INFORMATION

1.6.1 REACTOR INTEGRITY

Reactor Pressure Vessel (RPV)

With the present fuel type and management policy, Unit 1 is expected to reach a 40-year RPV life. On this unit, the fuel type and management policy have been modified to make that RPV life

span possible. Presently, a program is evolving for RPV life extension beyond the projected 40 years, potentially to 60 years, via a flux reduction program. A flux reduction program has started with the addition of eight absorbers in core corner positions, performance of vessel fluence calculations, and determination of an optimum power profile for each core load. Calculations using current methodology and uncertainty predict a significant RPV life extension, but not to 60 years. Excore dosimetry installed for the current cycle [with planned removal in October, 1994] will be used to reduce calculation uncertainty.

Due to different design and construction characteristics, Unit 2 RPV life expectancy exceeds 60 years. Low leakage core designs are now used for economic reasons, however the low leakage designs provide even greater life expectancy.

Reactor Coolant Pressure Boundary

On this CE plant, ECCS-to-RCS injection points are isolated by at least two check valves and one closed MOV. High pressure safety injection (HPSI), low pressure safety injection (LPSI), and containment spray (CS) pumps' common containment sump suctions are isolated from the containment sump by one closed MOV in conjunction with a closed seismic piping system. The CS headers are isolated from containment by one closed MOV and a check valve in conjunction with a closed seismic piping system. CVCS has the normal complement of two automatic actuation isolation valves.

1.6.2 REACTOR SHUTDOWN

Reactor Protection System

The reactor protection system provides protection for the reactor fuel and its cladding by providing automatic reactor shutdowns (8 trips) based on input from reactor power, reactor coolant pressure, coolant temperature, coolant flow, steam generator pressure, and containment pressure. The RPS is a redundant four-channel system that operates on a two-out-of-four logic.

ATWS Protection

ATWS protection, outside the normal reactor protection system, is initiated via the ESF pressurizer pressure signal. It actuates by opening contactors in the output of the CEA MG sets, thereby interrupting control element assembly power at its source. This protection has been installed on both units per CE, the NSSS, recommendations.

Remote Shutdown Facilities

These facilities are located in the switchgear rooms beneath each unit's control room.

1.6.3 CORE COOLING

Feedwater System

The main feedwater pumps are motor driven with each delivering 50 percent of the flow required for full power.

Turbine Bypass/Steam Dump Capacity

Each unit has five steam bypass valves, providing 45 percent of total capacity.

Unit 1 has one atmospheric dump valve per train (two trains) and Unit 2 has two valves per train. Each unit has the capability of dumping nine percent steam flow to the atmosphere.

Auxiliary Feedwater System

There are two motor-driven pumps on each unit with 100 percent capacity per pump. There is one steam-driven pump on each unit with 200 percent capacity. Any of the three pumps can inject to either steam generator. Automatic initiation and faulted steam generator protection are provided by each unit's Auxiliary Feedwater Actuation System provided by the NSSS.

Emergency Core Cooling System

In each unit, there are two HPSI pumps and two LPSI pumps with no unit-to-unit cross-connections. One pump of each type per unit will handle a postulated LOCA. The LPSI pumps also provide decay heat removal as required when the unit is shut down.

Decay Heat Removal

As indicated above, the LPSI pumps also provide decay heat removal as required when the unit is shut down by taking suction from the RCS (hot legs), passing the fluid through the shutdown cooling heat exchangers, and returning it to the RCS (cold legs). The heat removing medium is CCW - discussed in section 1.7.6 below. Shutdown cooling flow path overpressure protection is provided by automatic isolation valves and various relief valves in the system.

1.6.4 CONTAINMENT

Pressure Control/Heat Removal

There are two containment spray pumps and four containment fan coolers available per unit to suppress pressure spikes and cool the containment. One CS pump and two fan coolers will handle a postulated LOCA. There are no unit-to-unit cross-connections. This engineered safety feature is automatically started by ESFAS.

Hydrogen Control

Containment hydrogen control post-LOCA is accomplished on each unit by two trains of hydrogen recombiners located on the operating deck inside containment. By elevating, in a controlled manner, the temperature of containment atmosphere flowing through the recombiner, the recombiner units recombine hydrogen and oxygen to form water, thus preventing the buildup of hydrogen to potentially explosive levels.

1.6.5 ELECTRICAL POWER

Offsite AC

The station switchyard is connected to the transmission system by three independent 240 KV lines that share a right of way and interconnect with FPL's grid on the mainland approximately 10 miles West of the plant site. There are two independent offsite power feeds from the station switchyard to the emergency busses.

Onsite AC

Onsite AC power is provided by four EDGs (two per unit). EDGs are independent of other plant systems except vital DC power for control of starting. A Station Blackout (SBO) cross connection is installed and tested. This cross-connection serves the emergency busses directly and reduces cross-connect time to less than 15 minutes.

DC Power

Two trains of vital batteries per unit have been routinely tested for four-hour DC load profiles. Recently, due to cell replacement, they have been tested for three-hour battery capacity instead. The battery capacity test is harsher than the load profile test. There are four normal chargers per unit with swing chargers available for service. Non-safety batteries can be cross-connected to the safety-related swing bus if needed.

Instrumentation Power

Each unit has four inverters, two powered from each vital DC train, that provide four trains of instrumentation power.

Station Blackout Resolution Status

Unit 2 is a four-hour "DC coping" plant per the original license while Unit 1 is subject to the station blackout (SBO) rule of 10 CFR 50.63 requiring additional licensee action (unit-to-unit cross-connect of 4160V bus).

1.6.6 SAFETY-RELATED COOLING WATER SYSTEMS

Intake Cooling Water (Service Water)

Intake cooling water (ICW) for each unit originates in a common canal called the Intake Canal. The canal level varies with the tides since it is filled by a level difference between the Atlantic Ocean and the canal. One 16-foot and two 12-foot diameter pipes pass under the beach to connect the ocean and canal. The intake pipe ends in the Atlantic are covered by intake structures (rebuilt in 1991) intended to limit flow velocities, particularly vertical velocity, to reduce marine life entrapment. After use, ICW returns to the ocean through a Discharge Canal and under-beach pipes.

Each unit has two trains of ICW plus a swing pump that can be aligned to either train electrically and physically. The licensee has converted the deep draft ICW pumps from externally (water) lubricated to self-lubricated to increase reliability of the lubrication water source. The 100 percent (each) capacity pumps take suction from the intake canal via a canal intake structure using traveling screen debris protection. The intake canal structures adjacent to the ICW pump suctions are continuously injected with a hypochlorite solution to reduce marine growth in the associated piping and heat exchangers. Commencing 3/92, periodic injection of a clamicide at the intake structures, primarily to control marine growth affecting the turbine condensers, has also somewhat reduced marine growth affecting the ICW system.

The ICW pumps move water through two trains of heat exchangers that cool component cooling water (CCW) and two trains of heat exchangers that cool main turbine cooling water. During a postulated accident, water flow isolates from the turbine cooling heat exchangers. The discharge from the heat exchangers returns via the discharge canal to the ocean.

Increases in debris and silt in the heat exchangers during 1993 indicated that the intake canal needed dredging.

- As of September 1993, the utility was routinely cleaning main condenser waterboxes at reduced power and obtaining necessary dredging permits from the state and Corps of Engineers.

- The canal was dredged in December 1993 and January 1994 with immediate results of reduced waterbox fouling.

Closed Cooling Water Systems

Each unit has two trains of Component Cooling Water (CCW). The arrangement of two pumps and a swing pump mimics the ICW system.

The swing pump can be aligned to either train. The 100 percent (each) capacity pumps drive water through the CCW/ICW heat exchangers and then on to the heat loads, mainly the containment fan coolers and the shutdown cooling (decay heat) heat exchangers (which also can operate as containment spray heat exchangers). Additionally, CCW cools a variety of bearings, seals, and oil coolers for the HPSI, LPSI, and CS pumps. A non-safety-related portion of the CCW system cools reactor coolant pump seals and the spent fuel pool. This section isolates upon engineered safety features actuation.

1.6.7 SPENT FUEL STORAGE

Wet storage capability exists up to the year 2002 (Unit 2) and 2007 (Unit 1).

1.6.8 INSTRUMENT AIR SYSTEM

Instrument air compressors and driers, installed several years ago on each unit, provide all instrument air for Unit 2 and all but containment air for Unit 1. These have increased instrument air reliability. Unit 1 also has instrument air compressors inside containment.

1.6.9 STEAM GENERATORS

Each unit has two large steam generators (SGs) rather than the three or four usually seen. The licensee has begun to focus on a Unit 1 SG replacement in 1997. The SGs are under construction at the B&W Canada shops and a site organization is functioning.

1.7 EMERGENCY RESPONSE FACILITIES/PREPAREDNESS

Emergency Operations Facility:	10 miles West of site, I-95/Midway Rd. Exit
Technical Support Center:	Onsite, Adjacent to Unit 1 Control Room
Operational Support Center:	Onsite, 2nd floor of North Service Building

The last annual emergency preparedness exercise was held February 9, 1994. Two followup items were identified; one involving the definition of containment failure and one involving the need to demonstrate a protected area evacuation. An evacuation drill on September 30, 1994, satisfactorily demonstrated the accountability program. The next emergency preparedness exercise is scheduled for May, 1995.

Since St. Lucie site has a high probability of hurricanes, communications facilities were improved following the Turkey Point experience with Hurricane Andrew in August, 1992. Improvements include:

- High Frequency Auto-link with other FPL sites and NRC.
- Enhanced 900 MHZ System for site and mobile communications, with radios also in the licensee's EOF and county emergency facility.
- Cellular phones with hardened antennas.
- Hardened Local Government Radio antenna ties.

1.8 PRESENT OPERATIONAL STATUS (10/5/94)

Unit 1 is operating at 100% power and has been operating since a reactor startup on June 8 following a reactor trip on June 7.

Unit 2 is operating at 100 % power and has been operating since a reactor startup on July 15 following a July 14 shutdown to repair a stuck-closed trip circuit breaker.

Availability Factors:

	Unit 1	Unit 2
1991	81.0	100.0
1992	96.5	75.2
1993	74.0	71.8
1994 (through 8/94)	94.8	69.3
Cumulative (through 8/94)	77.3	82.4

1.8.1 UNIT 1 OPERATING HISTORY (Past Twelve Months)

Unit 1 operated continuously during the past 12 months with the following exceptions:

On November 1, 1993, Unit 1 experienced a dropped rod event due, apparently, to a loose power supply card. The CEA was recovered without incident.

On January 1, 1994, SALP period 10 ended.

On January 9, 1994, the unit was manually tripped when the 1B Main Feedwater Pump spuriously tripped. Post trip response was normal and the unit was returned to power on January 10. On the first attempt at restart, the reactor failed to achieve criticality by the time an all-rods-out condition was reached. The root cause was the use of outdated core physics curves, which were updated. The second attempt at startup was successful.

On March 28, 1994, Unit 1 experienced an automatic reactor trip when a maintenance foreman opened the generator exciter breaker. The worker had been issued a clearance on the Unit 2 exciter breaker and mistakenly entered the wrong unit's exciter control cubicle.

On April 2, 1994, the unit was returned to power; however, the unit automatically tripped on April 3 from 19% power while deenergizing a 4160 Volt non-vital bus to allow safe removal for maintenance of a failed startup transformer output breaker. The planned electrical lineup placed the A emergency bus on its EDG, which was running at a different frequency from the grid. The paralleled CEA MG sets, now with different frequency drivers, developed circulating currents, resulting in several tripped circuit breakers. A partial reactor trip tripped the turbine, which tripped the reactor. Unit 1 returned to power on April 4, 1994.

On June 6, 1994, Unit 1 tripped during a severe thunderstorm. The main transformer locked out the generator, causing a reactor trip, due to a phase differential on main generator transformer 1A. This occurred as a result of an approximately 8' length of flashing from an adjacent building which was blown across two phases of the 1A main transformer output. The licensee conducted inspections and tests of the 1A and 1B main transformers and the main generator, and performed repairs to the 1A main transformer. The reactor was taken critical on June 8; however, the licensee elected to remain off-line until repairs were completed to the 1A main transformer. Unit 1 was placed on line on June 11.

Unit 1 reduced power and entered mode 2 on August 28 to repair a DEH leak. The unit was returned to power approximately 18 hours later on the same date.

1.8.2 UNIT 2 OPERATING HISTORY (Past Twelve Months)

Unit 2 operated continuously during the past 12 months with the following exceptions:

On October 31, 1993, power was reduced to 45% to extend the fuel cycle to February 15, 1994. The downpower lasted until mid December.

On November 2, 1993, Unit 2 was manually tripped when operators noted increasing generator hydrogen temperature. The cause for the noted condition was tied to a temperature control valve in the Turbine Cooling Water system which starved the generator hydrogen coolers of water. A contributor to this event was the operation of the system with only one pump while leaving both turbine lube oil coolers in service. The procedure in place at the time of the event did not recognize the potential for starving the hydrogen coolers of TCW in such a lineup.

On November 3, 1993, Unit 2 was returned to power and operated at approximately 45% until December 13, when power was increased to 100%.

On December 25, 1993, power was reduced to 30% in response to a condenser tube leak. Repairs were effected the same day and the unit was returned to 100% power.

On February 13, 1994, Unit 2 was shut down for the 1994 refueling outage. The outage lasted 65 days.

As a function of the outage, Unit 2 entered reduced inventory conditions twice. The first occurrence began February 19 and supported reactor disassembly, reactor coolant pump seal package replacement, and the installation of steam generator nozzle dams. The second occurrence commenced March 16 and supported reactor vessel reassembly, reactor coolant pump seal package replacement, and steam generator nozzle dam removal. Coolant inventory was controlled well during these evolutions.

On March 16, 1994, the licensee identified boron deposits indicative of leakage from one of four pressurizer steam space instrument nozzles. Licensee investigations identified unacceptable linear indications in three of four nozzle pressure boundary welds. The steam space nozzles were constructed of Inconel 690 and were installed in 1993 as replacements for existing Inconel 600 nozzles, which had been found to be cracked. The new nozzles were attached with Inconel 600-equivalent weld material, as 690-equivalent material was not approved for use at the time. The licensee determined that the indications were the result of Primary Water Stress Corrosion Cracking (PWSCC).

The licensee's corrective actions involved repairing all four nozzles by creating new pressure boundary welds at the exterior wall of the pressurizer. The new welds were of the Inconel 690-compatible material. During the repair efforts, region-based inspectors found that the overall repair effort was well controlled and that performance was good; however, one violation was identified involving incorrect bevel angles on two weld preps.

On March 18, Unit 2 experienced a six minute cessation of shutdown cooling when a misanalyzed clearance (tagout) resulted in automatic valve realignments that secured flow to one of two operating shutdown cooling trains. A second shutdown cooling loop was in operation at the time; however, operators stopped the operating pump as a precaution against damage after the unexpected valve realignments. Operators assessed the situation and restored shutdown cooling in six minutes.

Unit 2 completed the refueling outage and was returned to power on April 19, 1994.

On April 23, 1994, Unit 2 tripped due to a RPS cabinet manufacturer's wiring error which manifested itself during RPS troubleshooting. The wiring error existed since the original manufacture of the cabinet.

Following Unit 2 trip stabilization of April 23, 1994, the steam bypass control system operated unexpectedly, resulting in a rapid 7 degree cooldown and a resultant severe RCS shrink (pressurizer heaters deenergized on low pressurizer level). Prompt operator action was taken to secure the cooldown. Unit 2 was returned to power on April 26, 1994.

On July 9, 1994, Unit 2 turbine was shut down and reactor power reduced to Mode 2 because the 2B1 RCP lower oil level indication showed a leak. The sump was not leaking and an unusual failure in the indication system was determined to be the reason for the indication. The reactor was returned to mode 1 and the turbine started up on July 10, 1994.

On July 14, 1994, Unit 2 was shut down to allow repair of a stuck-closed trip circuit breaker. Operators did not follow Unit 2 Tech Spec LCO time requirements regarding shut down on July 14 to allow repair of a stuck-closed trip circuit breaker. The unit was restarted and placed on line on July 15, 1994, and has operated continuously since that date.

1.9 OUTAGE SCHEDULE AND STATUS

Unit 1's last refueling outage began on March 29, 1993, and ended on May 28, 1993. Major outage activities included: refueling; steam generator tube inspection and plugging; station blackout related electrical cross-tie testing; Containment pressure sensing lines labelling and capping; Containment integrity violation corrective action (penetrations identified, caps installed); safety-related breaker protective relays - rewired for "green slime"; HFA latching relays verified operable; post-accident containment water level monitoring system - magnetic reed switch system installed; Mod to stop auxiliary building exhaust fan upon SI installed; radiation monitors replaced for liquid release to CCW and batch liquid release system; safety-related motor bearing alarm setpoints reduced per vendor request; EDG fan drive modification to reduce vibration; and mechanical, electrical, and I&C systems maintenance.

The next Unit 1 outage is scheduled to start October 30, 1994. It is currently being planned for 38 days. Major activities include: refueling; reactor vessel nozzle and flange weld ISI inspection; installation of a permanent cavity seal ring [at end of outage]; replacing reed switches for several CEAs; integrated safeguards test; steam generator tube inspection and plugging; steam generator sludge lancing; repair of refueling water storage tank; several instances of reduced inventory/ mid-loop operations; replacement of ICW/CCW LOOP logic [HFA latching relays] with pull-to-lock switches; removal [collection] of Rx vessel neutron flux dosimetry; modification of EDG skids to allow access underneath; inspection of ECCS sump area; and mechanical, electrical, and I&C systems maintenance.

Unit 2's last refueling outage began on February 13, 1994, and ended April 17, 1994. Major outage activities included: refueling; steam generator tube inspection and plugging; low pressure turbine blading replacement; emergency diesel generator inspection; replacement of two reactor coolant pump mechanical seals; and mechanical, electrical, and I&C systems maintenance. The next Unit 2 refueling outage is scheduled for October, 1995.

PART 2 - PLANT PERSPECTIVE

2.1 GENERAL PLANT PERSPECTIVE

A SALP presentation was conducted on February 15, 1994, covering the SALP period of May 3, 1992, through January 1, 1994. The facility was rated category 1 in all functional areas for the second consecutive SALP period.

In June 1994, St Lucie was dropped from the NRC management list of good performers after experiencing five unit reactor trips in the first half of 1994.

2.2 SALP HISTORY (Past 2 SALP Periods)

The last SALP period, SALP Cycle 10, ended on January 1, 1994. The current SALP period ends on July 1, 1995.

ASSMT. PERIOD	OPS	RAD	MNT/SURV	EP	SEC	ENG/TECH	SAQV
5/1/89 - 10/31/90	1	1	2	1	1	1	1
11/1/90 - 5/2/92	1	1	1	1	1	1	1

ASSMT. PERIOD	PLANT OPS	MAINTENANCE	ENGINEERING	PLANT SUPPORT
5/3/93 - 1/1/94	1	1	1	1

2.3 SELECTED SALP AREA DISCUSSIONS

Since the assessment of the SALP period ending in January, 1994, there have been no events that should significantly change the overall assessment of this facility. A new corrective action program, the St. Lucie Action Report Star System, was implemented in July, 1994. This program will be used to identify, review, analyze, resolve, track, and close out all plant discrepant conditions. It is intended to provide increased emphasis in this area. The program is currently being run in parallel with other existing programs until it is debugged. Full

implementation is planned by the end of 1994. To date, 215 items have been identified and 59 of these have been closed.

Plant Operations

Operator performance has historically been excellent. Transients and off-normal situations have been handled well by the operators.

Increased Reactor Trips

Operators have responded well to 6 reactor trips since November, 1993. The dates and root causes are as follows:

11/2/93 Unit 2 manual trip due to high generator cold gas temperature. Operation of TCW system with one pump and two TLO heat exchangers, erratic temperature control valve operation were root causes of condition.

1/9/94 Unit 1 manual trip due to MFP trip. Cause of electrical malfunction leading to MFP could not be determined. Instrumentation deemed most probable causes for the trip were replaced. Autopsy of equipment inconclusive.

3/28/94 Unit 1 automatic reactor trip when maintenance foreman mistakenly opened generator exciter breaker on wrong unit. Human error.

4/1/94 Unit 1 automatic trip due to inadequate electrical lineup which led to circulating currents between CEA MGs, resulting in TCB trips. Inadequate procedure review.

4/23/94 Unit 2 automatic trip caused by preexisting RPS cabinet wiring error. Fabrication flaw dating from original manufacture.

6/6/94 Unit 1 automatic trip due to main generator lockout when severe thunderstorm blew debris across main transformer output. Weather-related.

- While the number of reactor trips is high, given the timeframe in which they occurred, only the 11/2/93 and 4/1/94 trips appear to be related in that both involved review of unusual operating lineups.
- The human error-related trip of 3/28/94 did not involve operators.
- Two trips were related to equipment deficiencies; however, one involved a preexisting condition and one involved a spurious, non-repeatable, failure.

- The weather-related trip involved a piece of aluminum flashing, which was ripped from a building by high winds and blown across transformer terminals; it was not the result of a housekeeping problem.

- Operators performed well in responding to all trips, particularly the 4/23/94 trip, which was followed by a SBCS failure which resulted in an opening of 4 steam bypass control valves. Prompt operator action secured the ensuing cooldown.

- The two procedure-related trips may be indicative of a general lack of rigor in procedure review. The general topic of procedural adequacy is discussed below.

In conclusion, the recent increase in the number of reactor trips does not appear to be indicative of an overall declining level of performance; however, additional attention to the adequacy of operations procedures may be indicated. Operator performance following the trips has been good, and, in two cases, operators properly inserted manual trips in response to plant conditions. These actions indicated a good ability to quickly assess plant conditions and to take manual action prior to automatic action.

Other Operational Observations

A mispositioned valve was discovered on February 17, 1994. With Unit 2 in Mode 5 beginning a refueling outage, the licensee discovered that the Unit 2 auxiliary spray would not work because manual auxiliary spray isolation valve V2483 was mispositioned to locked-closed and had been in the incorrect position for about 13 months. Operators had positioned and independently verified the valve to be locked open in January, 1993. This was the first mispositioned valve since the June, 1991 SLIII for a mispositioned component cooling water valve. Management action in response to this event was swift and decisive. Disciplinary action was taken against the operators involved and management expectations with regard to independent verification was reiterated. The inspectors have noted a positive effect of the management actions on the general conduct of operations.

During the 1994 Unit 2 refueling outage, the licensee entered reduced inventory conditions twice. In both cases, preparations and operator performance was excellent.

On August 29, the resident inspector found that Unit 1 had the swing bus 1 AB aligned to DG 1A in order to permit work on expansion joints in the intake structure. IR 94-12 had found that this alignment had not been tested to verify the load shedding and sequencing feature. The licensee actions in the previous violation had focused on amending surveillance procedures to test these features during the next refueling outage and had not included measures to prevent placing the plant in this untested

alignment. This item is unresolved awaiting the completion of outage testing to determine the safety significance.

Management routinely makes conservative decisions regarding plant operations to the extent that they recognize the conservative path. An example was the decision to repair the Unit 1 shutdown cooling suction isolation valve body-to-bonnet leak even though the leak rate was a fraction of that allowed by TS. Another example was the decision to remain off-line while repairs were completed on the 1A main transformer. The slowness to shut down Unit 2 when TCB5 failed to trip was a noted exception from the historical performance.

The program for conduct of infrequently performed tests or evolutions at St. Lucie Plant has dramatically improved the performance of these activities by requiring special planning and management involvement prior to the test or evolution.

Procedural Adequacy

Recent inspections have noted a number of procedural deficiencies, requiring Temporary Changes (TCs) to be made before activities could proceed. While the majority of the TCs involved items of marginal safety significance, in several of these procedures, the existence of the deficiencies in question were clearly the result of inadequate review. One recent review error, involving a transpositional error of fuel assembly coordinates in the refueling Recommended Move List, contributed to an attempt to grapple two fuel assemblies simultaneously. As stated above, procedural inadequacy has been a contributor in two recent plant trips.

It has been noted that operators have correctly obtained TCs as required, as opposed to attempting work-arounds. This may be due, in part, to recent management efforts to reinforce expectations for procedure compliance and independent verification. However, the nature of the errors being identified suggests that attention be paid to the licensee's procedure review process.

Management Activities

Management has recently taken actions to refocus personnel attention on day-to-day activities. Trips to other sites by plant staff have been curtailed, as have visits by delegations from other organizations. All such activity is now subject to approval by the site vice-president. Additionally, the morning meeting format has been changed to include a more detailed discussion of plant operation and maintenance activities.

In response to recent concerns over the adequacy of the licensee's corrective action programs, site management has initiated a feasibility study on the topic of consolidating corrective actions programs. The stated goal is to reduce the number of individual programs in deference to a limited number of comprehensive

programs, thus reducing the probability of inadequately documenting or evaluating plant conditions. The adequacy of corrective actions has been implicated in several recent issues, including:

- The adequacy of surveillance testing of the units' swing ICW and CCW pumps, in light of previous NRC findings on the subject.

- Damage to Unit 2 PORV tailpipe supports incurred during a water hammer event in 1993. The damage was identified by NRC during an inspection during the 1994 Unit 2 outage. The licensee's inspections following the original event failed to address these tailpipes.

The licensee's approach to the issue appears to be sound and potentially far-reaching.

Conclusions

Although an increased number of challenges to plant operation have occurred in the recent past, operator performance and the general conduct of operations has remained strong. Management has been aggressive in addressing identifiable problems and their actions appear to be effective. Increased attention to the adequacy of normal operating and operational surveillance procedures appears to be warranted.

Maintenance

General

Maintenance/surveillance went from a SALP category 1 to a category 2 three SALP periods ago; this broad category had been brought down by some inattention to detail in the mechanical area. This area then improved significantly and during the last two assessment periods was again rated SALP category 1. Performance during this SALP period has not degraded.

Housekeeping is above average. Implementation of a Plant Manager's List and a material condition group reporting to the plant general manager has been effective in maintaining general plant condition and appearance. A team inspects the plant each week and generates a corrective action list that is reviewed each week. This program has resulted in significant rewards and has generally reversed degrading conditions.

Overall plant physical condition has been rated as good to excellent by several team inspections (e.g., MTI, OSTI, EDSFI, and Service Water), and recently by NRC managers. The housekeeping and general plant condition have been addressed with positive statements in recent SALP reports.

Since the units are located adjacent to the Atlantic Ocean, in a salt-laden atmosphere, the licensee has had to aggressively pursue exterior equipment maintenance. Painting and in some cases metalizing of exterior equipment and of equipment that is exposed to chlorides is a continuous aspect of the preventive maintenance scheme.

Unit 2 Outage Activities

Unit 2 outage activities were generally handled well. Maintenance activities were well-coordinated and were supported by engineers working out of the maintenance shops. Maintenance engineering involvement was instrumental in identifying and correcting a control wiring deficiency involving the Unit 2 swing ICW and CCW pumps which prohibited the pumps from load shedding properly. The problem had existed from unit construction.

Maintenance activities surrounding the repair of pressurizer level instrument steam space nozzles were found to be well controlled and performed. However, the NRC found two instances in which weld preps, accepted by the vendor's QC inspectors, possessed bevel angles outside of the specified tolerances. Additional review found that the bevel angles were satisfactory for work but that plant engineering had specified an unnecessarily restrictive tolerance.

Engineering

Major modifications have been few during the last several years. These included the redesign and repair of the cooling water ocean intake structure, SBO electrical wiring modifications, and changing ICW pump bearing water lubrication from external to self-lubricating. Also, the four Unit 2 pressurizer steam space instrument nozzles were replaced with upgraded material (on 3/25/93). The licensee installed the redesigned Unit 1 EDG radiator fan drivers in Spring 1993. Unit 1 steam generator replacement is being planned for 1997.

The last SALP discussed plant modifications without design approval. The licensee has taken positive measures to correct this practice.

Engineering support to the plant has been good. Staff engineers were available and on-site throughout the Unit 2 outage to support PC/M work and were integral to the resolution of pressurizer steam space level instrumentation nozzle weld cracks. In fact, an engineer from site engineering was responsible for the identification of the boron deposits from the cracks. Engineering support was also noted in the leak repair of a Unit 1 shutdown cooling isolation valve body-to-bonnet leak. More recently, timely engineering support was noted in response to the weather-related damage to the 1A main transformer.

Recent reviews of the licensee's control of fuel quality indicated that Juno Nuclear Fuels and site Reactor Engineering personnel were heavily involved in reviews of vendor performance. Additionally, Reactor Engineering and Nuclear Fuels engineers have supported control room operators during plant startups and shutdowns.

Recent inspection has indicated that potential problems exist in the area of vendor technical manual control. Additional inspection is planned in this area.

Plant Support

Radiological Controls

The radiological control program continues to be effective with increased use of engineering controls and reduced respirator usage which were considered program strengths. External and internal exposures were well controlled. Worker adherence to RWPs and radiological procedures was excellent. The licensee continues to reduce the contaminated area, and personnel contamination events are consistently below goals. Audits were adequate; however, they tend to be compliance based. Management continued to support developmental training programs for health physics technicians.

The ALARA program was effective with several initiatives this period including use of robotics, new nozzle dams, and a reduction in microfiltration. The site HP organization maintains remotely controlled submersibles used both by St. Lucie and Turkey Point. The licensee has recently placed an order for two robots to perform inspections inside the containment biological shield at power.

Radiological controls for the Unit 2 outage were noteworthy. The licensee made extensive use of closed-circuit cameras to remotely provide HP coverage while maintaining dose rates ALARA. Good HP control of major evolutions, such as reactor vessel head lift, was also noted.

Emergency Preparedness

The licensee continues to maintain an effective EP program.

Security

Security upgrades made prior to the last SALP were notable. The licensee continues to maintain a very effective security program.

Fire Protection

The licensee continues to maintain an effective fire protection program.

Housekeeping

Housekeeping has been generally very good.

PART 3 - SIGNIFICANT EVENTS

3.1 SIGNIFICANT EVENTS BRIEFINGS (Past 12 Months)

Unit 1: None this period

Unit 2: Failure of a GE AK-25 Trip Circuit Breaker

3.2 ENFORCEMENT STATUS/HISTORY (Past 12 Months)

Currently, there are no escalated enforcement actions pending at St. Lucie.

The misalignment of bus 1AB to DG1A which could render the DG inoperable and the incorrect CR log entries in this issue are currently unresolved, awaiting refueling outage testing to determine safety significance. This item may be the subject of an enforcement conference.

PART 4 - STAFFING AND TRAINING

4.1 OPERATIONS STAFF - OVERALL (8/94)

Above average performance of the operations staff has been noted. Control room demeanor of personnel is above average.

Number of Shifts: (RCO, SRO) Six shift rotation, 8-hour shifts; (NPO, ANPO, SNPO) Five shift rotation, 8-hour shifts.

Number of SROs:	22 active/21 inactive* / 43 total
Number of ROs:	30 active/2 inactive/ 32 total
Total Licensed Operators:	52 active/23 inactive/ 75 total

* 3 SROs perform only RO duties and maintain SRO licenses active only for RO duties. This practice is being reviewed by RII operator licensing.

4.2 WORK FORCE (8/94)

	FPL	Contractor
Plant personnel (excluding disciplines below)	713	122
Training	63	0
Quality Assurance/ISEG/SPEAKOUT	49	0

Materials Management	46	0
Security	11	122
Site Engineering	42	0

4.3 OPERATOR QUALIFICATION/REQUALIFICATION PROGRAM (Past Two Years)

4.3.1 REQUALIFICATION PROGRAM

NRC-administered requalification exams were completed in October, 1992. Results were good - 9 of 12 RO's passed and 12 of 12 SRO's passed. Three of the RO's failed the written exam and one also failed the JPMs. The program was rated satisfactory. Requalification exams are currently in progress (10/94). To date, 20 of 24 SRO's and 17 of 20 RO's have passed all portions of the exams. Failures have included 5 written exams, 1 JPM, and 1 simulator failure.

4.3.2 INITIAL EXAMS

Previous initial operator exams were conducted on April 29, 1991. Six SRO upgrades were examined, and all six passed. Additional exams were completed October 25, 1991. Six operators, 2 SRO upgrades, and 1 instant SRO were examined. All passed. The last initial exam was given April 27 through May 1, 1992, to 6 SRO upgrades and 2 ROs, and all passed. A hot license class of 15 persons was started in late February, 1992 (14 still in class). The last initial exam was conducted in October 1993 - 10 of 10 prospective ROs passed. Initial exams are planned for October, 1994, with 3 ROs and 7 SRO Upgrades planned

4.3.3 GENERIC FUNDAMENTAL EXAM

On an NRC administered Generic Fundamental Exam on June 6, 1990, 6 of the 10 St. Lucie operators who took the exam passed. On February 6, 1991, 3 of 3 operators who took the exam passed. On June 6, 1991, one operator took the exam and passed. On February 10, 1993, all 12 operators who took the exam passed. One person took the exam on February 9, 1994, and passed. No further Generic Fundamental Exams have been taken.

4.4 PLANT SIMULATOR

The simulator is on site and fully certified to meet ANSI/ANS 3.5, 1985.

4.5 INPO ACCREDITATION

All training programs are maintaining INPO accreditation. The site specific simulator has been used for training since 1988 and has been fully certified for approximately 4 years. Eight separate NRC

inspections in the form of operator examinations at the simulator have found no serious problems.

PART 5 - INSPECTION ACTIVITIES

5.1 INSPECTION FOLLOWUP OPEN ITEMS SUMMARY (UNITS 1 AND 2 COMBINED) (10/6/94)

Division	Pre 93	Total	Change from Last Report
DRP	3	30	0
DRS	0	7	-3
DRSS	0	2	0
Totals	3	39	-3

Note: Each item that applies to both units is counted as one item.

5.2 MAJOR INSPECTIONS

IR-No.	Date	Type
89-02	1/89	RG-1.97
89-03	3/89	NDE
89-07	3/89	EQ
89-09	3/89	Design Control
89-24	10/89	Maintenance Team Inspection
89-27	11/89	EOP Followup
90-09	4-5/90	OSTI
91-03	2-3/91	EDSFI
91-18	9/91	MOV (no negative findings)
91-201	9-10/91	Service Water Inspection
92-14	7/92	Emergency Preparedness Program
92-17	7/92	EDSFI Followup
93-01	1/93	Check Valves
94-11	5/94	MOV Followup

5.3 PLANNED TEAM INSPECTIONS

None

5.4 INFREQUENT INSPECTION PROCEDURE STATUS

No core modules are overdue at this time.

5.5 SIMS STATUS - OPEN TMI ITEMS

There are no open TMI items.

ATTACHMENT 3

NRR OPERATING REACTOR ASSESSMENT

NRR ASSESSMENT FOR ST. LUCIE

October 1994

CURRENT ISSUES

-Seismic qualification of electrical and mechanical equipment (GL 87-02, USI A-46) issue on Unit 1 is still not resolved. The staff issued a letter in early 1994 providing a general framework of criteria which would resolve this issue. FPL responded in May 1994 restating their previous position and stating that they believe that further NRC requests for work, evaluations, or plant changes would provide no additional safety benefit to their nuclear facilities. The staff is considering performing a backfit analysis to determine the possibility of ordering FPL to implement additional actions or accept the licensees position. A third alternative being evaluated is performance of a site inspection to determine if any safety-significant issues exist in the areas of disagreement.

-Unit 1 will be replacing steam generators in 1997. The licensee is well into planning for the event.

-An alternative approach to the resolution of the Thermo-Lag issue was proposed by FPL, however, the staff did not pursue review of this performance based approach based on Commission direction of this issue. The licensee is scheduled to submit to the staff by early November 1994 a schedule and method for resolution of the Thermo-Lag issue.

-The plant continues to perform well. The latest SALP evaluation had ratings of 1 in all categories.

Contact:

Jan A. Norris
504-1483

August 12, 1994

ST LUCIE

Recent Significant Events/ Findings

Date	Cause	Identified	Event/Finding
11/2/93	Operating procedures	Licensee	Unit 1 manual trip - abnormal turbine cooling water lineup at reduced power
1/1/94	-	-	SALP period ended
1/9/94	Equipment failure	licensee	Manual trip - feed pump control circuit failure
2/8/94	-	-	TPPR Conducted
2/17/94	Operator error	Licensee	Mispositioned valve discovered. Aux. pressurizer spray isolation valve had been locked closed (vice open) since 3/27/93.
2/28/94	Procedure & operator error	Licensee / NRC	Inadequate grappling of a fuel assembly caused by error in Recommended Move List and operator error in following procedure (IR 94-09). Two related TS interpretation questions: Adequacy of a single operator on refueling bridge during core alterations; and required level of review and approval of Recommended Move List.
3/7/94	Management decision	NRC	A nonconservative licensee entry into a TS LCO action statement for 1A EDG fuel oil tank level was identified by the NRC (IR 94-09).
3/16/94	Equipment failure	Licensee	A pressurizer instrument nozzle that had been repaired a year ago was found leaking. Failure a year ago was in Inconel 600 nozzle. The repair used an Inconel 690 nozzle and Inconel 182 shielded metal arc weld material. The repair was inspected by NRC, with 1 VIO for incorrect weld rod size. Current failure attributed to PWSCC of Inconel 182 shielded metal arc weld material. A new mod (re-using the Inconel 690 nozzles and an external Inconel 690 weld) is being inspected by NRC (Crowley/Coley).

3/16/94	Engineering error	NRC	Regional inspector had two violations: 1) corrective action for an 11/24/92 water hammer event was done without documented instructions or procedures, resulting in operating until 3/94 with five snubbers on the SRV and PORV tailpipes inoperable. 2) Failure to write a nonconformance report for a damaged pipe support in March 1994.
3/28/94	Maintenance error	Licensee	Unit 1 auto reactor trip. Maintenance foreman opened generator exciter breaker - on wrong unit. Operators had clearance on Unit 2.
3/29/94	Equipment failure	Licensee	Licensee discovered body-to-bonnet leak on non-isolable ten-inch shutdown cooling isolation valve. Leak rate about two drops/second (TS-allowable). Licensee installed exterior clamp and leak repair compound on valve.
4/2/94	Equipment failure	Licensee	Startup transformer output breaker mechanically fails to open. Bkr returned to mfgr for analysis.
4/3/94	Personnel Error (Lack of sufficient depth in review of procedure change)	Licensee	Unit 1 auto reactor trip from 19% power while deenergizing the 4160 Volt non-vital bus to allow safe removal of the failed SU Tx output breaker for maintenance. The isolation placed the A emergency bus on the EDG, which was running at a different frequency from the grid. The paralleled CEA MG sets, now with different frequency drivers, developed circulating currents and several tripped circuit breakers. A partial reactor trip tripped the turbine, which tripped the reactor.
4/3/94	Personnel error	Licensee	During testing for Unit 2 modifications the licensee discovered that the 4160 V [AB Bus] swing bus components [C ICW Pump and C CCW Pump] would not strip from the bus upon undervoltage if the bus were aligned to the B bus. A missing jumper wire in the switchgear (from initial construction) was the proximate cause. (SL4, Inadequate Corrective Action for 1992 NRC VIO for inadequate surveillance test - IR 94-12)

4/7/94	Personnel error	NRC	Contractor personnel made and contractor QC accepted pressurizer nozzle weld prep that did not meet procedural requirements for bevel angle. Licensee engineering had specified overly tight tolerances. (IR 94-10)
4/16/94	Equipment failure	Licensee	Cracked weld in RCS pressure boundary - 3/4 inch instrument line attached to 2B1 12-inch safety injection header. Licensee accomplished weld repair using SI-to-loop check valve for isolation. (IR 94-12)
4/21/94	Operator inattentive ness	Licensee	Unit 2 reactor power increased from 26 to 31% due to positive MTC and operator inattentiveness. (IR 94-12)
4/23/94	Mfg. error	Licensee	Unit 2 auto reactor trip from 30% power caused by RPS cabinet wiring error for trip bypass circuit, from original unit construction. (IR 94-12)
4/23/94	Equipment failure	Licensee	Following unit 2 trip, steam bypass system operated unexpectedly and dropped RCS temp by seven degrees F, pressurizer heaters turned off. Prompt operator action was taken. Extensive mechanical repairs were required. Unit 2 was returned to power on April 26, 1994. (IR 94-12)
6/6/94	Equipment failure	licensee	Unit 1 trip from 100% power during a severe thunderstorm when the main transformer locked out the generator, causing a reactor trip. The lockout occurred due to a phase differential on main generator transformer 1A. This occurred as a result of an approximately 8' length of flashing, from an adjacent building, which was blown across two phases of the 1A main transformer output. The reactor was taken critical on June 8; however, the licensee elected to remain off-line until repairs were completed to the 1A main transformer. Unit 1 was placed on line on June 11.

7/9/94	Equipment failure	Licensee	Unit 2 turbine was shut down and reactor power reduced to Mode 2 because the 2B1 RCP lower oil level indication showed a leak. The sump was not leaking and an unusual failure in the indication system was determined to be the reason for the indication. After repair, the reactor was returned to Mode 1 and the turbine started up on July 10, 1994. (IR 94-15)
7/14/94	Equipment failure	Licensee	During surveillance test, TCB 5 failed to open. It had stuck shut. A broken piece of bakelite had fallen into the trip mechanism.
7/14/94	Personnel Error	NRC	Operators did not follow Unit 2 Tech Spec LCO time requirements regarding shut down on July 14 to allow repair of a stuck-closed trip circuit breaker. The unit was restarted and placed on line on July 15, 1994. (IR 94-15)
8/12/94	personnel Error	NRC	The licensee was unloading new fuel for Unit 1 with a hoist grapple that was missing the safety latch sleeve locating pin. The safety sleeve functioned by friction only.

NRC CONCLUSION: The mispositioned valve and water hammer occurred over a year ago. None of the above personnel errors are similar. These events and findings may be precursors to declining performance. Further very close inspection and assessment is required.

August 12. 1994

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3/16/94	Engineering error	NRC	Regional inspector had two violations: 1) corrective action for an 11/24/92 water hammer event was done without documented instructions or procedures, resulting in operating until 3/94 with five snubbers on the SRV and PORV tailpipes inoperable. 2) Failure to write a nonconformance report for a damaged pipe support in March 1994.
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IPSCO001 INSPECTION FOLLOW-UP SYSTEM-POWER REACTOR REPORT NUMBER 1 02/21/95
SITE ITEM LIST PAGE 1
SORTED BY REPORT NUMBER

SITE: ST LUCIE 050-00335 ST LUCIE 1 STATUS: OPEN SEVERITY:
050-00389 ST LUCIE 2 REPORT FROM: TO:
REPORT ON: ALL ITEMS

ABBR	OPNG I/R (IFS NBR)	SEQ	TYPE	P21/LER LOG NBR	LATEST REPORT	SEV/ SPL	REPORT TRANSMTL	STS	CLOSEOUT PROJ/ACT*	CLSOUT ORG	TITLE
STL1	91-011	1	VIO	95-04C		3/1	05/17/1991	O		2232	FAILURE TO MAINTAIN THE OPERABILITY OF THE U
STL2	91-011							O			
STL1	91-011	2	VIO	95-04C		3/1	05/17/1991	O		2232	FAILURE TO VERIFY VALVE POSITIONS IN PRESCRI
STL2	91-011							O			
STL1	92-018	2	IFI	APRIL 95	94-013	95-04C	10/21/1992	O		2232	EVALUATE ADEQUACY OF ACCIDENT PREPARATIONS P
STL2	92-018				94-013			O			
STL1	93-001	1	URI		93-001		02/23/1993	O		2313	OPERABILITY DETERMINATION OF VALVES PER GL 9
STL2	93-001				93-001			O			
STL1	93-012	1	VIO	APRIL 95	95-04C	4/1	06/21/1993	O	09/30/1993	2232	INADEQUATE LPSI PUMP MAINTENANCE PROCEDURE C
STL2	93-025	1	IFI				12/01/1993	O		2313	REVIEW OPERABILITY OF UNIT 2 MOV MV-08-13 DU
STL2	93-378*		LER	93-007-00	MAY 95		05/21/1993	O	95-07C	2232	MANUAL REACTOR TRIP AFTER THE SIMULTANEOUS D
STL1	93-379*		LER	93-005-00	95-04C		05/30/1993	O		2232	SHUTDOWN REQUIRED BY TS DUE TO AN UNLATCHED
STL2	93-999*		LER	93-008-00	MAY 95	95-04C	11/02/1993	O		2232	MANUAL REACTOR TRIP DUE TO HIGH GAS TEMPERAT
STL1	94-004	1	IFI	95-03C			03/04/1994	O		2412	DEFINITION OF CONTAINMENT FAILURE
STL2	94-004							O			
STL2	94-008	1	VIO	95-02C		4/1	04/08/1994	O		2312	FAILURE TO FOLLOW CORRECTIVE ACTION PROCEDUR
STL2	94-008	2	VIO	95-02C		4/1	04/08/1994	O		2312	INADEQUATE INSPECTION & EVALUATION OF WATERH
STL1	94-008	3	URI	95-02C			04/08/1994	O		2312	QUALITY LEVEL OF PORV AND SRV DISCHARGE PIPI
STL2	94-008							O			
STL1	94-010	1	VIO			4/1	04/28/1994	O		2312	FAILURE TO MEET WELD PREP DIMENSIONAL TOLERA
STL1	94-011	1	VIO			4/1	06/02/1994	O		2313	INADEQUATE CORRECTIVE ACTION FOR MOVS WHICH
STL1	94-011	2	IFI				06/02/1994	O		2313	INADEQUATE RECOGNITION OF MOV TEST PRESSURE

1

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INFORMATION ON THIS PAGE IS FOR O F F I C I A L U S E O N L Y .
INSPECTION FOLLOW-UP SYSTEM-POWER REACTOR REPORT NUMBER 1
SITE ITEM LIST
SORTED BY REPORT NUMBER

SITE: ST LUCIE 050-00335 ST LUCIE 1
050-00389 ST LUCIE 2
STATUS: OPEN SEVERITY:
REPORT FROM: TO:
REPORT ON: ALL ITEMS

ABBR	OPNG I/R (IFS NBR)	SEQ	TYPE	P21/LER LOG NBR	LATEST REPORT	SEV/ SPL	REPORT TRANSMTL	STS	CLOSEOUT PROJ/ACT*	CLSOUT ORG	TITLE
STL1	94-011	3	IFI				06/02/1994	O		2313	LACK OF INSTRUCTIONS OR GUIDANCE FOR TRENDIN
STL1	94-012	1	VIO	Closed 95-09		4/1	05/20/1994	O		2232	INADEQUATE CORRECTIVE ACTION FOR PREVIOUS VI
STL2	94-012							O			
STL1	94-013	2	DEV	95-04C			06/27/1994	O		2232	INADEQUATE EMERGENCY SUPPLIES IN CONTROL ROO
STL2	94-013							O			
STL1	94-019	2	URI				10/20/1994	O		2321	ACCEPTABILITY OF MAINTAINING AN SRO AS AN RO
STL2	94-019							O			
STL1	94-019	3	IFI				10/20/1994	O		2321	CONFLICTING PROCEDURAL GUIDANCE FOR ACTIVE L
STL2	94-019							O			
STL1	94-021*		LER	93-009-00	may-		11/17/1993	O	95-07C	2232	ENGINEERED SAFETY FEATURES ACTUATION DUE TO
STL1	94-022	1	VIO	Closed 95-04		4/1	11/25/1994	O		2232	INADEQUATE CORRECTIVE ACTIONS TO NRC VIOLATI
STL1	94-022	2	VIO	Closed 95-09		4/1	11/25/1994	O		2232	IMPROPER MODIFICATION OF CONTROL ROOM LOGS
STL1	94-024	2	VIO	95-04C		4/1	12/14/1994	O		2232	INADEQUATE PROCESS FOR CHANGES TO VENDOR TEC
STL2	94-024							O			
STL1	94-063*		LER	94-002-00	94-24C		01/13/1994	O		2232	INADVERTENT LOAD SHED OF THE 1A3 4160 VOLT B
STL2	94-077*		LER	94-001-00	95-01C		02/17/1994	O		2232	PRESSURIZER AUXILIARY SPRAY OUT OF SERVICE C
STL2	94-110*		LER	94-002-00	95-04C		03/16/1994	O		2232	PRESSURIZER INSTRUMENT NOZZLE WELD CRACKING
STL2	94-115*		LER	93-005-00	95-04C		01/12/1993	O		2232	HIGH REACTOR COOLANT PUMP VIBRATION RESULTIN
STL1	94-138*		LER	94-003-00	95-01C		04/23/1994	O		2232	AUTOMATIC REACTOR TRIP DURING FUNCTIONAL TES
STL2	94-169*		LER	94-003-00	2-thru 95-01C			O		2232	AUTOMATIC REACTOR TRIP DURING FUNCTIONAL TES
STL2	94-230*		LER	94-004-00	95-07C		06/28/1994	O		2232	PLANT VENT WIDE RANGE GAS MONITOR OUT OF SER

SITE: ST LUCIE 050-00335 ST LUCIE 1 STATUS: OPEN SEVERITY:
050-00389 ST LUCIE 2 REPORT FROM: TO:
REPORT ON: ALL ITEMS

ABBR	OPNG I/R (IFS NBR)	SEQ	TYPE	P21/LER LOG NBR	LATEST REPORT	SEV/ SPL	REPORT TRANSMTL	STS	CLOSEOUT PROJ/ACT*	CLSOUT ORG	TITLE
STL1	94-300	1	IFI				11/17/1994	O		2324	PROCEDURAL GUIDANCE FOR REMOVAL OF RCPS PRIO
STL2	94-332*		LER	94-006-01	94-24C		07/14/1994	O		2232	TRIP CIRCUIT BREAKER FAILURE DUE TO A BROKEN
STL1	94-376*		LER	94-008-00	95-04C		11/04/1994	O		2232	INADVERTENT CONTAINMENT ISOLATION SIGNAL
STL1	95-004*		LER	94-010-00	95-09C		11/24/1994	O		2232	INADVERTENT B TRAIN ENGINEERED SAFEGUARDS FE
STL1	95-005*		LER	94-009-00	95-09C		11/22/1994	O		2232	INADVERTENT SAFETY INJECTION ACTUATION SIGNA

TOTAL OPEN ITEMS 48
TOTAL OPEN SEQUENCES 37

*IF ITEM IS OPEN, THE PROJECTED CLOSEOUT DATE IS SHOWN
IF ITEM IS CLOSED, THE ACTUAL CLOSEOUT DATE IS SHOWN

IFSC0001 INSPECTION FOLLOW-UP SYSTEM-POWER REACTOR REPORT NUMBER 1 01/09/95
SITE ITEM LIST PAGE 1
SORTED BY REPORT NUMBER

SITE: ST LUCIE 050-00335 ST LUCIE 1
050-00389 ST LUCIE 2
STATUS: OPEN SEVERITY:
REPORT FROM TO:
REPORT ON: ALL ITEMS

ABBR	OPNG I/R (IFS NBR)	SEQ	TYPE	P21/LER LOG NBR	LATEST REPORT	SEV/ SPL	REPORT TRANSMTL	STS	CLOSEOUT PROJ/ACT*	CLSOUT ORG	TITLE
STL1	91-011	1	VIO			3/1	05/17/1991	0			2232 FAILURE TO MAINTAIN THE OPERABILITY OF THE U
STL2	91-011							0			
STL1	91-011	2	VIO			3/1	05/17/1991	0			2232 FAILURE TO VERIFY VALVE POSITIONS IN PRESCRI
STL2	91-011							0			
STL1	92-018	2	IFI		94-013		10/21/1992	0	95040		2232 EVALUATE ADEQUACY OF ACCIDENT PREPARATIONS P
STL2	92-018				94-013			0			
STL1	93-001	1	URI		93-001		02/23/1993	0			2313 OPERABILITY DETERMINATION OF VALVES PER GL 9
STL2	93-001				93-001			0			
STL1	93-012	1	VIO			4/1	06/21/1993	0	09/30/1993		2232 INADEQUATE LPSI PUMP MAINTENANCE PROCEDURE C
STL2	93-025	1	IFI				12/01/1993	0			2313 REVIEW OPERABILITY OF UNIT 2 MOV MV-08-13 DU
STL2	93-378*		LER	93-007-00			05/21/1993	0			2232 MANUAL REACTOR TRIP AFTER THE SIMULTANEOUS D
STL1	93-379*		LER	93-005-00			05/30/1993	0	95040		2232 SHUTDOWN REQUIRED BY TS DUE TO AN UNLATCHED
STL2	93-999*		LER	93-008-00			11/02/1993	0	95040		2232 MANUAL REACTOR TRIP DUE TO HIGH GAS TEMPERAT
STL1	94-004	1	IFI				03/04/1994	0			2412 DEFINITION OF CONTAINMENT FAILURE
STL2	94-004							0			
STL2	94-008	1	VIO			4/1	04/08/1994	0			2312 FAILURE TO FOLLOW CORRECTIVE ACTION PROCEDUR
STL2	94-008	2	VIO			4/1	04/08/1994	0			2312 INADEQUATE INSPECTION & EVALUATION OF WATERH
STL1	94-008	3	URI				04/08/1994	0			2312 QUALITY LEVEL OF PORV AND SRV DISCHARGE PIPI
STL2	94-008							0			
STL1	94-010	1	VIO			4/1	04/28/1994	0			2312 FAILURE TO MEET WELD PREP DIMENSIONAL TOLERA
STL1	94-011	1	VIO			4/1	06/02/1994	0			2313 INADEQUATE CORRECTIVE ACTION FOR MOVS WHICH
STL1	94-011	2	IFI				06/02/1994	0			2313 INADEQUATE RECOGNITION OF MOV TEST PRESSURE

FF/38

STL1	94-011	3	IFI			06/02/1994	0	2313 LACK OF INSTRUCTIONS OR GUIDANCE FOR TRENDIN
STL1	94-012	1	VIO	STAR 179 match IEI will find	4/1	05/20/1994	0	2232 INADEQUATE CORRECTIVE ACTION FOR PREVIOUS VI
STL2	94-012						0	
~~STL1~~	~~94-013~~	2	DEV			06/27/1994	0	2232 INADEQUATE EMERGENCY SUPPLIES IN CONTROL ROO
~~STL2~~	~~94-013~~						0	
STL1	94-019	2	URI	Awaiting J. Mowman		10/20/1994	0	2321 ACCEPTABILITY OF MAINTAINING AN SRO AS AN RO
STL2	94-019						0	
STL1	94-019	3	IFI			10/20/1994	0	2321 CONFLICTIMG PROCEDURAL GUIDANCE FOR ACTIVE L
STL2	94-019						0	
STL1	94-021*		LER	93-009-00		11/17/1993	0	2232 ENGINEERED SAFETY FEATURES ACTUATION DUE TO
STL1	94-022	1	VIO		4/1	11/25/1994	0	2232 INADEQUATE CORRECTIVE ACTIONS TO NRC VIOLATI
STL1	94-022	2	VIO		4/1	11/25/1994	0	2232 IMPROPER MODIFICATION OF CONTROL ROOM LOGS
~~STL1~~	~~94-024~~	2	VIO	95-04C	4/1	12/14/1994	0	2232 INADEQUATE PROCESS FOR CHANGES TO VENDOR TEC
~~STL2~~	~~94-024~~						0	
~~STL1~~	~~94-053*~~		LER	~~94-002-00~~	94-24C	01/13/1994	0	2232 INADVERTENT LOAD SHED OF THE 1A3 4160 VOLT B
STL2	94-077*		LER	94-001-00 Seam		02/17/1994	0	2232 PRESSURIZER AUXILIARY SPRAY OUT OF SERVICE C
~~STL2~~	~~94-110*~~		~~LER~~	~~94-002-00~~ (95-04C)		03/16/1994	0	2232 PRESSURIZER INSTRUMENT NOZZLE WELD CRACKING
~~STL2~~	~~94-115*~~		~~LER~~	~~93-005-00~~ (95-04C)		01/12/1993	0	2232 HIGH REACTOR COOLANT PUMP VIBRATION RESULTIN
STL1	94-138*		LER	94-003-00		04/23/1994	0	2232 AUTOMATIC REACTOR TRIP DURING FUNCTIONAL TES
STL2	94-169*		LER	94-003-00 Schin			0	2232 AUTOMATIC REACTOR TRIP DURING FUNCTIONAL TES
STL2	94-230*		LER	94-004-00		06/28/1994	0	2232 PLANT VENT WIDE RANGE GAS MONITOR OUT OF SER
STL1	94-300	1	IFI			11/17/1994	0	2324 PROCEDURAL GUIDANCE FOR REMOVAL OF RCPS PRIO
~~STL2~~	~~94-332*~~		~~LER~~	~~94-006-01~~ 94-24C		07/14/1994	0	2232 TRIP CIRCUIT BREAKER FAILURE DUE TO A BROKEN
~~STL1~~	~~94-349*~~		~~LER~~	~~94-006-00~~ 94-25C		10/23/1994	0	2232 CONTAINMENT INTEGRITY OUTSIDE OF FSAR ASSUMP
STL1	94-376*		LER	94-008-00		11/04/1994	0	2232 INADVERTENT CONTAINMENT ISOLATION SIGNAL
STL1	94-380*		LER	94-006-01 94-25C		10/23/1994	0	2232 CONTAINMENT INTEGRITY OUTSIDE OF FSAR ASSUMP
STL1	95-004*		LER	94-010-00		11/24/1994	0	2232 INADVERTENT B TRAIN ENGINEERED SAFEGUARDS FE

~~STL1 94-25 1 NCV (closed)~~ 2232 - Inadequate Design Control

STL1	95-005*	LER	94-009-00	11/22/1994	0	2232 INADVERTENT SAFETY INJECTION ACTUATION SIGNA

TOTAL OPEN ITEMS	50
TOTAL OPEN SEQUENCES	39

*IF ITEM IS OPEN, THE PROJECTED CLOSEOUT DATE IS SHOWN
IF ITEM IS CLOSED, THE ACTUAL CLOSEOUT DATE IS SHOWN

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

September 19, 1994

MEMORANDUM TO: Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects I/II, NRR

FROM: Bruce A. Boger, Acting Director
Division of Reactor Projects, RII

SUBJECT: REQUEST FOR ASSISTANCE IN ADDRESSING ISSUES REGARDING ST LUCIE UNITS 1 AND 2 REFUELING PROCEDURES (TIA 94-023)

St. Lucie Inspection Report 94-09 contains two items which are unresolved (Attachment 1) pending Technical Specification (TS) interpretations. The licensee had dissenting comments on these issues, as noted in the inspection report Exit Interview paragraph. The two items are:

1. URI 389/94-09-02, Adequacy of a single operator on the refueling bridge during core alterations - paragraph 4.a

   This URI involves interpretation of Unit 2 TS 6.2.2.d, which states:

   > "All CORE ALTERATIONS shall be observed by a licensed operator and supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation. The SRO in charge of fuel handling normally supervises from the control room and has the flexibility to directly supervise at either the refueling deck or the spent fuel pool."

   During the St. Lucie Unit 2 fuel shuffle, on March 1, 1994, the licensee had stationed one [licensed] operator on the refueling bridge to perform refueling operations. This single licensed person, who was in constant communication with the refueling control desk in a control room annex, was performing actual refueling operations, which included operating the bridge and crane. The SRO in charge of the evolution was located remote from the refueling bridge, as is allowed by the TS and discussed in FPL and NRC correspondence (Attachments 2 and 3).

   The inspector questioned staffing adequacy because the operator had earlier attempted to grapple a fuel bundle with the crane at incorrect coordinates due to a move list error. The single operator had not detected the error by cross check between analog and digital positioning systems. The inspector questioned whether this one [though licensed] person using the bridge and crane to perform core alterations met the TS requirement and the NRC's intent regarding a licensed operator observing core alterations.

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The licensee's position was that "observed by a licensed operator" refers to the historical practice when nonlicensed persons, perhaps from a contract service company, actually performed the core alterations. The licensee believes that 'performing' includes 'observing' when a licensed operator performs core alterations. The licensee stated that licensee and NRC correspondence (Attachments 2 and 3), generated during the original Unit 2 licensing process, supports their interpretation that a licensed operator performing core alterations constitutes the TS-required observer. The inspectors reviewed Attachments 2 and 3, and found that they appear to address the location of the SRO rather than the "observing - performing" question.

In addition to compliance with the TS, the inspectors had the following concerns with having only one person on the refueling bridge:

- There was no real-time independent verification of core alterations as they were performed. However, the core load was verified in detail by serial number, orientation, etc. when the core shuffle was complete.

- From the crane operating station on the bridge, the operator did not watch activity in the refueling canal. The operator could look down through plexiglass or move a few feet and look over the edge of the crane bridge with binoculars, but did not regularly do so. Also, there was a TV camera mounted near the bottom of the refueling mast, but it was not working. Thus the operator was, in a sense, driving 'on instruments only.'

Please provide an interpretation (with supporting considerations) of TS 6.2.2.d:

- Does "core alterations shall be observed by a licensed operator" refer to literally directly observing fuel move or does the phrase refer more to the process activities and supervision involved?

- Is the TS requirement based upon the assumption that contract or maintenance department personnel, requiring licensed operator oversight, perform fuel movement?

- Is the TS requirement based upon the need for real-time independent verification of core alterations or fuel movement?

- Does the TS require a second licensed operator, in addition to the [licensed] refueling machine operator, to observe fuel movement or other core alterations?

- If so, then does the TS require that supervision of core alterations be performed by an SRO who is separate from the observer (i.e., a third person)?

2. URI 389/94-09-03, Adequacy of review and approval of refueling core alterations (licensee's Recommended Move List) - paragraph 4.a

This URI involves interpretation of Unit 2 TS 6.8.1, 6.8.2, and 6.8.3 with regard to the licensee's "Recommended Move List."

- TS 6.8.1.a requires procedures recommended by Regulatory Guide 1.33, Revision 2, Appendix A. RG 1.33 recommends procedures for "Preparation for Refueling and Refueling Equipment Operation" and for "Refueling and Core Alterations."

- TS 6.8.1.b requires procedures for "Refueling Operations."

- TS 6.8.2 requires that each of those procedures, and changes thereto, shall be reviewed by the FRG and approved by the Plant General Manager prior to implementation.

- TS 6.8.3 allows temporary changes to those procedures provided:

  - The intent of the procedure is not altered.

  - The change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's license on the unit affected.

  - The change is documented, reviewed by the FRG, and approved by the Plant General Manager within 14 days of implementation.

The licensee's Recommended Move List (Attachment 4) was the document that detailed the fuel assembly and CEA move sequence. It was developed during the core load development process and it identified, in order, each fuel assembly and CEA to be moved, the location from which it was to be moved, and the location to which it was to be moved. It not only addressed moves within the reactor vessel, but also moves between the fuel pool and reactor vessel, and moves within the fuel pool. It was invoked by Test Procedure 3200090, Refueling Operations, which also described steps necessary to deviate from [change] the list (see Attachment 5). However, the Recommended Move List itself was not part of the test procedure and was not reviewed by the FRG or approved by the Plant General Manager. Instead, it was approved by the Reactor Engineering Supervisor. Deviations from the Recommended Move List were approved by the reactor engineer on shift and the refueling coordinator (SRO).

During past refueling outages, many fuel or CEA movement sequence changes [as many as 90] have occurred due to equipment problems. Historically, the Recommended Move List had been part of a procedure but change management was a huge burden and resulted in lengthy delays, tired operators, and wasted radiation exposure. The licensee de-proceduralized it to cope with these problems.

The licensee now considers the Recommended Move List to be a non-procedure and therefore not subject to the TS 6.8.2 requirements for review and approval of procedures and also not subject to the TS 6.8.2 and TS 6.8.3 requirements for processing changes to procedures. The licensee stated that, since the Recommended Move List's preparation, use, and modification were directed by a FRG-reviewed procedure, a FRG review should not be required for the list itself. Subsequently, the licensee stated that a telephone review with other Combustion Engineering plants found that the licensee's position was common in the industry.

The inspectors had the following concerns with the licensee's practice of handling the Recommended Move List as a non-procedure:

- The Recommended Move List was an important document. It was used by reactor engineers and operators for performing safety-related activities. Errors in it could potentially lead to unsafe conditions of fuel arrangement. However, the licensee was requiring less review and approval for the Recommended Move List than for a safety-related procedure.

- The retention of a record of the Recommended Move List could be of significant value in determining the cause of an accident or malfunction, as described in ANSI 45.2.9 - 1979, Section 2.2.1. However, the licensee often issued a new Recommended Move List and discarded the old one with no formal review and no record retention.

Please determine if the Recommended Move List is considered to be a procedure, subject to the requirements of TS 6.8.1, 6.8.2, and 6.8.3.

St. Lucie Unit 1 is scheduled to begin a refueling outage on October 31, 1994. Please let me know if you will not be able to respond to this request by that time. If you have any questions concerning this request, please contact K. Landis (404/331-5509) or R. Schin (404/331-5561).

Docket No. 335 DPR-57
389 DPR NPF-15

Attachments: 1. Applicable portions of IR 50-335,389/94-09
2. Ltr. from FPL to NRC dtd. Sept. 22, 1981, regarding SRO Refueling Supervisor

Attachments cont'd: (See page 5)

Attachments cont'd:
3. Ltr. from NRC to FPL dtd. Sept. 30, 1981, regarding Refueling SRO
4. Recommended Move List
5. Applicable portions of Test Procedure 3200090, Refueling Operations

cc w/attachments:
J. Norris, NRR
T. Johnson, Turkey Point SRI
S. Elrod, St. Lucie SRI
K. Landis, RII
R. Cooper, RII
E. Greenman, RIII
B. Beach, RIV
K. Perkins, WCFO
S. Vias, TSS, RII

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

Florida Power & Light Company
ATTN: J. H. Goldberg
President - Nuclear Division
P. O. Box 14000
Juno Beach, Florida 33408-0420

Gentlemen:

SUBJECT: (NRC INSPECTION REPORT NOS. 50-335/94-09 AND 50-389/94-09)

This refers to the inspection conducted by S. A. Elrod of this office on February 27 - March 26, 1994. The inspection included a review of activities authorized for your St. Lucie facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

The enclosed Inspection Report identifies activities that violated NRC requirements that will not be subject to enforcement action because the licensee's efforts in identifying and/or correcting the violation meet the criteria specified in Section VII.B. of the NRC Enforcement Policy.

Your attention is invited to two unresolved items identified in the inspection report. These matters will be pursued during future inspection.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

Should you have any questions concerning this letter, please contact us.

Sincerely,

Orig signed by David M. Verrelli

David M. Verrelli, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Attachment 1

Enclosure: (See page 2)

9405230001 TP

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

Report Nos.: 50-335/94-09 and 50-389/94-09

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: February 27 - March 26, 1994

Inspectors:

S. A. Elrod, Senior Resident Inspector — Date Signed

T. Johnson, Senior Resident Inspector — Date Signed

M. S. Miller, Resident Inspector — Date Signed

M. A. Scott, Resident Inspector — Date Signed

L. Trocine, Resident Inspector — Date Signed

R. Schin, Project Engineer — Date Signed

Approved by: for K. D. Landis, Chief — 4/28/94 — Date Signed
Reactor Projects Section 2B
Divisior of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted onsite in the areas of plant operations review, Unit 2 refueling observations, surveillance observations, maintenance observations, outage activities, and fire protection review.

Backshift inspection was performed on February 28 and March 1, 2, 3, 13, 15, 16, 17, 19, and 20.

Attachment 1

Results: Plant Operations area:

Operators performed Unit 2 reduced inventory operations well. Unit 1 operations continued to be good. One non-conservative licensee entry into a technical specification limiting condition for operation action statement was identified, involving emergency diesel generator fuel oil tank level. Failure to follow refueling procedures resulted in a failed attempt to grapple a fuel assembly due to bridge mispositioning. (paragraphs 3 and 4)

Maintenance and Surveillance area:

Maintenance activities, both normal and outage related, were generally conducted well. Several procedural weaknesses were identified and were addressed by the licensee. Surveillances were performed satisfactorily; However, operator and procedural weaknesses were identified during an EDG surveillance run. (paragraphs 5, 6, and 7)

Plant Support area:

Health Physics coverage of outage-related maintenance was strong, as was health physics personnel response to a spill of potentially contaminated water. (paragraphs 3 and 6)

One non-cited violation (NCV) and two unresolved items (URIs) were identified:

NCV 50-389/94-09-01, Incorrect Grappling of a Fuel Assembly, paragraph 4.a.

URI 50-389/94-09-02, Adequacy of a Single Operator on the Refueling Bridge During Core Alterations, paragraph 4.a.

URI 50-389/94-09-03, Adequacy of Review and Approval of Refueling Core Alterations, paragraph 4.a.

above gallon numbers for each tank were converted from feet and inches by the inspector.) The inspector found no clear necessity or net safety benefit in pumping the 1A EDG fuel oil tank level down below its TS-required minimum. In this case, placing the 1A EDG in a TS LCO action statement was a non-conservative action by the licensee.

Also, the inspector found that the licensee tracked and reviewed overall unavailability of certain safety systems, but did not track or review overall time in LCO action statements for any safety systems. Unavailability and inoperability are substantially different. For example, in this case the 1A EDG was considered to be inoperable for eight hours but was also considered to be available during the same time.

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.

In conclusion, operations for this inspection period were conducted satisfactorily. Operator knowledge and control of Unit 2 reduced inventory operations were considered to be excellent. One licensee voluntary entrance into a TS LCO action statement, involving EDG fuel oil tank level, was considered to be non-conservative.

4. Unit 2 Refueling Observations (60710)

The inspectors reviewed the licensee's refueling activities and operations including surveillance testing, operating procedures, TS compliance, shift manning, reactor engineering involvement, management and supervision oversight, plant conditions, housekeeping, and loose object control.

a. Unit 2 Refueling and Core Shuffle

The licensee commenced Unit 2 refueling and core shuffle activities on February 28, 1994. The inspectors monitored refueling from the control room, the spent fuel area and the refueling bridge. During fuel movement the licensee controlled the move sequence by using a Recommended Move List. This list was part of the core reload PC/M 001-294 for Unit 2 Cycle 8. Fuel movement operations were controlled by procedures OP 2-1630024, Refueling Machine Operations, and Test Procedure 3200090, Refueling Operations. The test procedure referenced the Recommended Move List and described the steps necessary to deviate from this list.

On February 28, 1994, at 11:43 a.m. refueling operations were stopped during an attempt to grapple assembly H08 in core location

G11. The hoist overload energized several times during the upward hoist motion attempts. The licensee discovered a typographical error in the Recommended Move List at step 27. The core coordinate for the bridge was listed as 787.71 and should have been 783.71. Consequently, the bridge was misaligned by approximately 4 inches. The licensee surmised that the grapple engaged the assembly off center and upward movement was arrested due to actuation of the hoist overload. The refueling SRO directed reactor engineering to check for additional errors in the Recommended Move List. Three more errors were found and corrected.

In followup to this error, the inspector reviewed operating procedure No. 2-1630024, "Refueling Machine Operation". In order to assure the operation has the correct core location, a comparison check of rough mechanical alpha-numeric grid coordinates was directed. Then, a more exact coordinate was to be made using the digital bridge and trolley indicators. The operator, during move number 27 for assembly H08 in core location G11, did not ensure that the two coordinates checked were in agreement prior to attempting to grapple the fuel assembly. Consequently, the typographical error in the Recommended Fuel Movement List caused the operator to grapple the assembly in an incorrect position.

The licensee stated that the operator in question was recently qualified and his experience may have been a causal factor. Step 8.2.11.B.3.b of procedure 2-1630024 requires the operator to ensure that the mechanical indicator for the core coordinates agree with the bridge and trolley digital readouts. TS 6.8.1.a and b, and Regulatory Guide 1.33, Revision 2, February 1978, Appendix A, items 2k and 2l require procedures for refueling and core alteration to be written, implemented, and maintained. Due to the minor safety significance of this error and the licensee's prompt corrective action, this violation will not be subject to enforcement action because the licensee's efforts in identifying and/or correcting the violation meet the criteria specified in Section VII.B of the NRC Enforcement Policy. The failure to adequately follow procedure 2-1630024 in conjunction with the error in the Recommended Move List are identified as NCV 50-389/94-09-01, Incorrect Grappling of a Fuel Assembly.

The inspectors reviewed the appropriate logs including the RCO log book, the refueling log and others. During the February 28, 1994, refueling error associated with step 27, the RCO log book stated that the fuel movement had stopped (for almost 4 hours); however, the reason was not stated. Further, the restart of refueling (at approximately 3:52 pm) was logged in the RCO log book. The inspectors discussed this issue with operations and plant management.

On March 1, from approximately 11:00 a.m. to 1:30 p.m., the inspectors observed refueling operations from the containment including the refueling bridge and from the area of the spent fuel

pool. During this time, an additional error in step 61 of the Recommended Move List was noted by the licensee in that the fuel movement sheets incorrectly indicated that no CEA was in the fuel assembly. The licensee corrected this error.

During this time, the inspector noted that only one licensed operator was on the bridge performing refueling operations. TS 6.2.2.d requires that all core alterations be observed by a licensed operator and supervised by an SRO with no concurrent responsibilities. This SRO may be in the control room, the refueling bridge, or the spent fuel pool area. The inspector questioned the validity of having only one person on the refueling bridge, and whether this meets the intent of a licensed operator "observing core alterations". The licensee's position was that a single operator met this requirement. However, considering the error noted above, a second person checking or observing could have prevented this. Pending further NRC review, this issue is identified as URI 50-389/94-09-02, Adequacy of a Single Operator on the Refueling Bridge during Core Alterations.

The inspectors noted that the Recommended Move List and changes were not specifically reviewed by the FRG nor approved by the Plant Manager, but instead were approved by the reactor engineering supervisor. Each movement is also a core alteration. TS 6.8.1 requires procedures for refueling operations and core alterations. TS 6.8.2 requires those procedures to be FRG reviewed and plant manager approved. Pending further NRC review, this issue is identified as URI 50-389/94-09-03, Adequacy of Review and Approval of Refueling Core Alterations.

The inspectors discussed these concerns with licensee management and on March 2, at about 10:30 am, the licensee suspended refueling operations. The licensee initiated the following corrective actions:

- Revision of Test Procedure 3200090 to incorporate the Recommended Move List in the procedure and to track changes to the Recommended Move List in an Appendix to the procedure.
- Revalidation of the Recommended Move List.
- FRG review and approval of the Recommended Move List per TCs 2-94-076 and 077.
- Initiation of a formalized deviation sheet signoff for Fuel Movement Changes.
- Documented qualifications of each refueling operator.
- Implemented infrequent evolution process, including detailed briefing, per AP 0010020.
- Stressed the importance of RCO log keeping during briefings.
- Added a second person on the refueling bridge to ensure proper fuel movements.

The inspector met with licensee management and attended the morning shift briefings on March 3. The inspectors verified corrective

actions and observed portions of the continuing refueling operations.

The inspectors also reviewed QA activities associated with the Unit 2 refueling. Based on discussions with QA management personnel, the inspector determined that QA had performed audits, surveillances and performance monitoring of refueling activities including:

- new fuel receipt,
- refueling preparations,
- TS compliance,
- monitoring of refueling activities in the control room, on the refueling bridge and in the SFP,
- procedure review, and
- CEDM unlatching.

Independent QC verification of the final core configuration and QA review of core physics testing were planned. QA/QC did not identify any deviations, violations, or problem areas. The inspectors observed that QA/QC were not present during the February 28, 1994, error nor during the times the inspectors were present in the refueling areas and facilities.

b. CEA Shuffle

Following correction of the refueling process, the inspector monitored portions of the CEA shuffle on March 10. After completing the fuel assembly shuffle per the approved Recommended Move List, the licensee moved CEAs to their new required positions. The inspector noted that, toward the end of the CEA shuffle, operators found that two CEAs had been mis-located. The reactor engineer then made changes to the core load procedure to locate and move CEAs to correct the condition. The inspector verified that the procedure allowed the reactor engineer to make these changes.

c. Core Load Verification

Immediately after the CEA shuffle, the inspector observed the Unit 2 core load verification. This evolution was conducted from the refueling crane, using an underwater camera suspended by a pole from the crane handrail and two video displays on the crane deck. Licensee personnel involved in the evolution included an SRO in charge, an RO crane operator, a reactor engineer, and a quality control inspector. The operators positioned the camera while the engineer and QC inspector each read and recorded the fuel assembly and CEA numbers. They also made a video tape record of this evolution.

The inspector noted that, while the numbers on the CEAs and new fuel assemblies were clearly legible, many of the numbers on the partially used fuel assemblies were obscured by corrosion and small flakes of loose metallic oxidation (the engineer stated that this

was from the CEA shuffle) and were very difficult to read. The engineer and QC inspector had to discuss and relook at many such numbers before they agreed on what the number was. After both had viewed, recorded, and agreed upon all CEA and fuel assembly numbers, they compared their recorded numbers with the approved core map from the core load procedure. Three of the fuel assembly numbers did not match. Then the camera was repositioned to each of those three fuel assemblies until the reactor engineer and the QC inspector agreed with the numbers from the approved core load map.

The inspector concluded that the licensee's core load verification was adequate but was hampered by fuel assembly numbers being obscured by corrosion and small flakes of loose metallic oxidation.

In conclusion, while evolutions were generally conducted satisfactorily, the inspectors found several aspects of the Unit 2 refueling operation to be of concern. These concerns were relayed to the licensee, and plant management adequately addressed the issues. Failure to properly prepare and follow refueling procedures resulted in a failed attempt to grapple a fuel assembly due to bridge mispositioning. Questions related to TS-required levels of staffing on the refueling bridge resulted in a URI.

5. 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, remo, 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:

a. OP 1-2200050B, "1B Emergency Diesel Generator Periodic Test and General Operating Instructions"

The inspector witnessed the performance of 1B EDG surveillance test performed March 16. The test was performed satisfactorily; however, the inspector noted weaknesses associated with operator performance and procedural adequacy.

In preparing to perform the surveillance test, step 4 of the subject procedure requires that the water level in both EDGs' radiator expansion tanks be checked. The inspector noted, immediately prior to the performance of this step, that the water level in the 1B1 expansion tank was out-of-sight high in the tank's level sight glass (the procedure required that the level be visible between two points marked on the sight glass). The inspector witnessed the SNPO performing this evaluation to observe the sight glass and initial

9. Exit Interview

The inspection scope and findings were summarized on April 25, 1990, with those persons indicated in paragraph 1, above. The inspector described the areas inspected and discussed in detail the inspection results listed below. Proprietary material is not contained in this report. Dissenting comments were received from the licensee.

The licensee took issue with NCV 389/94-09-01. In this instance, an operator mispositioned the refueling machine and failed to grapple a fuel assembly due to incorrect coordinates in the Recommended Move List. The licensee stated that, while a cross check of machine coordinates following the move may have prevented the failed attempt to grapple, such a cross check was not procedurally required.

The licensee also took issue with URI 389/94-09-02. In this case, the inspector questioned whether a single licensed operator, performing core alterations on the refueling bridge, met the intent of the TS requirement for a licensed operator to "observe" core alterations. The licensee's position was that a licensed operator performing core alterations constituted the TS-required observer. The licensee indicated that they possessed NRC correspondence, generated during the original Unit 2 licensing process, which supported their interpretation.

The licensee also took issue with URI 389/94-09-03. In this case, the inspector found that the Recommended Move List (for fuel shuffle) was not reviewed by the FRG and was not approved by the plant manager. The licensee stated that the Recommended Move List's preparation, use, and modification were directed by an FRG-reviewed procedure and that an FRG review should not be required for the list.

Item Number	Status	Description and Reference
389/94-09-01	open	NCV - Incorrect Grappling of a Fuel Assembly, paragraph 4.a.
389/94-09-02	open	URI - Adequacy of a Single Operator on the Refueling Bridge During Core Alterations, paragraph 4.a.
389/94-09-03	open	URI - Adequacy of Review and Approval of Refueling Core Alterations, paragraph 4.a.

10. Abbreviations, Acronyms, and Initialisms

AFW	Auxiliary Feedwater (system)
ANPS	Assistant Nuclear Plant Supervisor
CCW	Component Cooling Water
CEDM	Control Element Drive Mechanism
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
CVCS	Chemical & Volume Control System

P.O. BOX 529100 MIAMI FL 33152

FLORIDA POWER & LIGHT COMPANY

September 22, 1981
L-81-415

Mr. James P. O'Reilly, Director, Region II
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
101 Marietta Street, Suite 3100
Atlanta, Georgia 30303

Dear Mr. O'Reilly:

Re: St. Lucie Unit 1
Docket No. 50-335
SRO Refueling Supervisor
IE Circular 80-21

NRC IE Circular No. 80-21 states that the NRC interpretation of the term "directly supervised" means that the SRO in charge of fuel handling is "supervising the core alterations from the refueling deck".

The St. Lucie Plant staff feels that this interpretation is counter-productive. The existing staffing which has been utilized for the past several years and is in accordance with the Plant Technical Specifications meets, as a minimum, the intent of the Circular for the following reasons:

1) Maintaining the SRO in charge of refueling in the control room provides much better overall control and coordination. He is continuously updated using the refueling status board and is in constant communication with all refueling stations. Additionally, the control room is designed and instrumented to be the center of overall plant operations. Placing the SRO on the refueling deck removes him from the mainstream of communications, plant status, and information, and would limit his awareness of overall plant operation.

2) Restricting the SRO to the refueling deck limits his ability to move rapidly to the spent fuel pool area where fuel movement may also be occurring.

3) St. Lucie utilizes licensed operators on the refueling machine, the spent fuel machine and on the communication headset in the control room to monitor wide range nuclear instrumentation. It appears that the Circular may be intended to provide more supervision at those utilities which may employ non-licensed fuel handlers. If so, it is felt that St. Lucie's existing arrangement exceeds the intent of the Circular.

Attachment 2

4) Placing the SRO in charge of fuel handling continuously on the refueling deck is not consistent with corporate and regulatory ALARA policies.

For the above reasons, and our opinion that adherence to the stated interpretation would detract from, rather than enhance, the safe handling of fuel, it is our intent to conduct refueling operations in accordance with past policy and the requirements of the Technical Specifications. Requiring the SRO to supervise from the control room with the freedom to move quickly to all refueling areas is more conducive to safe fuel handling than the method described in the NRC Circular.

As a result of a telephone conversation on September 18, 1981 with Mr. Hugh Dance of your staff, it is our understanding that [redacted] with FPL regarding the stationing of the SRO in charge of fuel handing in the control room. We further understand that you will inform the site NRC Resident Inspectors of this concurrence.

Very truly yours,

J. A. DeMarty
for

Robert E. Uhrig
Vice President
Advanced Systems & Technology

REU/PKG/ras

Attachment

cc: Harold Reis, Esquire

Attachment 2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W., SUITE 3100
ATLANTA, GEORGIA 30303

SEP 30 1981

RECEIVED
OCT 9 1981

Florida Power and Light Company
ATTN: Dr. R. E. Uhrig, Vice
President, Advanced Systems
and Technology
P.O. Box 529100
Miami, FL 33152

Gentlemen:

Subject: IE Circular 80/21

[redacted]

Thank you for your letter of September 22, 1981 which confirms your conversation with Mr. H. C. Dance of our staff. We concur with your intent to require the "Refueling SRO" to supervise from the control room with the freedom to move quickly to all refueling areas.

We appreciate your cooperation with us.

Sincerely,

Paul J. Kellogg, Chief
Reactor Projects Branch 2,
Division of Resident and
Reactor Project Inspection

cc: C. M. Wethy, Plant Manager
Nat Weems, QA Construction
Manager

Attachment 3

ST. LUCIE PLANT
PREOPERATIONAL TEST PROCEDURE NO. 3200080, REVISION 8
REFUELING OPERATION

APPENDIX E
RECOMMENDED MOVE LIST
EXAMPLE DATA SHEET

				From					To					
Step #	Assmbly	Insert	Orient	Core	Bridge	Trolley	SFP	NPS	Upnor	Core	Bridge	Trolley	SFP	Status
1		78		T11						R9				CEA MOVE-1/M
2		42		E11						B15				CEA MOVE-1/M
3		20		L17						R20				CEA MOVE-1/M
4		113		L5						Q2				CEA MOVE-1/M
5		106		L11						L17				CEA MOVE-1/M
6	Q21		270°	L2	800.06	857.21			West				Z37	Ensure Camera is Vertical
7	Q31		270°	B11	742.8	799.91			West				Z34	Ensure Camera is Vertical
8	Q22		270°	X11	857.44	799.99			West				Z32	Ensure Camera is Vertical
9	Q32		270°	L20	800.11	742.69			West				X37	Ensure Camera is Vertical
10	Q35		270°	L9	800.06	808.15			West				X34	Ensure Camera is Vertical
11	Q25		270°	N11	808.4	799.98			West				X32	Ensure Camera is Vertical
12	Q28		270°	J11	792.08	799.97			West				T37	Ensure Camera is Vertical
13	Q18		270°	L13	800.05	791.81			West				T34	Ensure Camera is Vertical
14	Q80		270°	W4	849.23	840.86			West				T32	Ensure Camera is Vertical
15	H02	20	270°	R20	816.88	742.74				L13	800.05	791.81		1/M
16	H03		270°	X7	857.44	816.29				N11	808.4	799.08		1/M
17	Q77		270°	V3	841.18	849.04			West				R37	Ensure Camera is Vertical
18	H04	42	90°	B15	742.84	783.83				J11	792.08	799.97		1/M
19	H01	113	90°	Q2	783.85	857.18				L9	800.06	808.15		1/M
20	Q71		90°	C4	760.94	840.89			West				R34	Ensure Camera is Vertical
21	Q76		90°	D3	759.17	849.05			West				R32	Ensure Camera is Vertical
22	Q72		90°	D19	759.25	760.87			West				N37	Ensure Camera is Vertical
23	Q69		90°	C18	751.04	759.09			West				N34	Ensure Camera is Vertical
24	Q73		270°	V19	841.18	750.93			West				M35	Ensure Camera is Vertical
25	Q78		270°	W18	849.29	759.02			West				S30	Ensure Camera is Vertical
26	H05	109	270°	L7	800.06	816.3				L2	800.06	857.21		1/M
27	H06	24	270°	G11	783.71	799.96				B11	742.8	799.91		1/M PRIOR TO UNGRAPPLE
28	Q57		270°	Q6	783.67	824.61			West				N30	Ensure Camera is Vertical
29	H07	56	270°	R11	816.61	799.95				X11	857.44	799.99		1/M PRIOR TO UNGRAPPLE
30	H08	21	270°	L15	800.05	783.61				L20	800.11	742.69		1/M
31	Q84		270°	R5	816.16	824.61			West				AA27	Ensure Camera is Vertical
32	H11		270°	R2	816.8	857.24				L7	800.06	816.3		1/M
33	H10		270°	X15	857.44	783.61				R11	816.61	799.95		1/M
34	Q56		270°	L11	800	800			West				Y27	Ensure Camera is Vertical
35	H12		270°	Q20	783.76	742.71				L15	800.05	783.61		1/M

Prepared by _____ R.E. Reviewed by _____ Approved by _____ R.E. Supervisor

/R8

Attachment 4

ST. LUCIE PLANT
PREOPERATIONAL TEST PROCEDURE NO. 3200090, REVISION 6
REFUELING OPERATION

Aug 16, 91

12.0 DETAILED PROCEDURE:

12.1 The Operations Supervisor has reviewed the status of all CORE ALTERATIONS, related systems, as well as the overall plant status, and authorizes the commencement of fuel movement.

Verified by_____ Date____/____/____
Operations Supervisor

12.2 All required personnel are on station.

Verified by_____ Date____/____/____

12.3 All fuel and insert moves will be directed from the Refueling Control Center in the following manner.

1. The Recommended Move List will be used as a move sequencing guide to refueling.

2. Deviations in the Recommended Move List sequence are permitted and alternate locations may be utilized as temporary locations provided the following are observed:

   A. Sources, or fuel assemblies meeting the minimum burnup requirements of 9.8.1 RX-A10, RX-Y10 (PSL 1) or RX-A10, RX-Y12 (PSL 2) if required, will be located in before any other fuel moves are permitted.

   B. Movement of an assembly is in accordance with the Fuel Assembly Storage Table (F.A.S.T.).

   C. Verify that the mast orientation is correct to support the new move.

   D. Verify that as a result of removing an assembly, no other assemblies become free standing.

   E. Verify that inserting an assembly into a new location in the core and ungrappling it would not cause it to be a free standing assembly.

   F. Verify that moving an assembly into a spent fuel Rack does not violate spent fuel pool region requirements or funnel requirements.

Attachment 5

ST. LUCIE PLANT
PREOPERATIONAL TEST PROCEDURE NO. 3200090. REVISION 6
REFUELING OPERATION

12.0 DETAILED PROCEDURE: (continued)

12.3 (continued)

2. (continued)

G. Any deviation is approved by the Reactor Engineer on shift and the Refueling Coordinator (SRO).

H. If the deviation does affect the FRG approved Final Core Loading Pattern, reactivity conservatism shall be ensured and FRG re-approval obtained prior to core verification.

3. The Refueling Control Center will inform the station conducting the move which assembly is to be moved, it's present location as well as where it is to be moved and changes in Refueling Machine mast orientation if required.

4. The station performing the move will acknowledge the directions issued by the Refueling Control Center prior to any movement. For the operator's convenience a Fuel Movement Log similar to that provided in this procedure will be provided for recording the instructions transmitted by the Refueling Control Center.

12.4 Refueling Control Center- Operating Personnel Responsibilities

1. Coordinate the movement of all fuel and core components. Refer to Appendices C and D for insert and CEA transfer guidance.

2. Receive notification of core component movement and acknowledge such notification by core component serial number(s), originating location, present location, core coordinates, and orientation of the Refueling Machine mast.

3. Verify Bridge and Trolley coordinates (hoist position upon insertion of a fuel assembly) stated by Refueling Machine Operator are valid for the core coordinates in the refueling sequence for the appropriate step, record on the Fuel Movement Log.

4. Track completion of each transfer by filling out the Fuel Movement Log. The Fuel Movement Log will then be used by Reactor Engineering to complete Appendix B, the final fuel transfer sequence at the conclusion of the fuel move, then update the Fuel Status Magnet Board.