

SLSR 894.WP

REGION II

ATLANTA, GEORGIA

PLANT STATUS REPORT

ST. LUCIE

AUGUST, 1994

FF/42

PLANT STATUS REPORT FOR ST. LUCIE (08/94)

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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 [EARLY AUGUST, 1994]:

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. E. Dawson (Bob) - Maintenance 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
 L. L. McLaughlin (Lamar) - Licensing Manager
 W. L. Parks (Bill) - Reactor Engineering Supervisor
 C. A. Pell (Ash) - Services Manager
 J. Scarola (Jim) - Operations Manager
 D. H. West (Dan) - Technical Manager
 J. A. West (Jeff) - Operations Supervisor

SITE [AFTER SEPTEMBER 1, 1994]:

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

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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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 G. C. Lainas (Gus), Assistant Director for Region II Reactors,
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 J. A. Norris (Jan), Senior Project Manager, Project
 Directorate II-2, (301) 504-1483

NRR [AFTER REORGANIZATION]:

S. A. Varga (Steven), Director, Division of Reactor Projects-I/II,
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 J. A. Zwolinsky (John), Deputy Director, Division of Reactor
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 J. A. Norris (Jan), Senior Project Manager, Project
 Directorate II-2, (301) 504-1483

AFOD:

S. Israel (Sandy), Reactor Operations Analysis Branch,
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1.4 LICENSE INFORMATION

	<u>Unit 1</u>	<u>Unit 2</u>
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

<u>Description</u>	<u>Units 1 and 2</u>
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. Both items are scheduled to be closed in 1994. 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, 1993. 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 (8/11/94)

Unit 1 is in day 60 of power operation following startup on June 8 following a reactor trip on June 7.

Unit 2 is in day 26 of power operation following startup on July 15 following a July 14 shutdown to repair a stuck-closed trip circuit breaker.

Availability Factors:

	<u>Unit 1</u>	<u>Unit 2</u>
1991	81.0	100.0
1992	96.5	75.2
1993	74.0	71.8

1994 (through 7/94)	94.4	64.8
Cumulative (through 7/94)	77.2	82.3

1.8.1 UNIT 1 OPERATING HISTORY (Past Twelve Months)

Unit 1 was returned to power on June 22, 1993, following a refueling outage.

Control Element Assembly #3 dropped during exercising on August 26, 1993. It was promptly recovered.

On September 18 and again on September 20 and September 22, 1993, Unit 1 was manually tripped (from 75, 63, and 11% power) due to jellyfish clogging the intake travelling screens, which required immediately stopping the affected circulating water pumps. Unit 1 operated at various reduced power levels for about two weeks due to the unusual numbers of jellyfish.

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.

The unit was returned to power on April 1; however, the unit tripped 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 and operated continuously until June 6, when the unit 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 and has operated continuously since that date.

1.8.2 UNIT 2 OPERATING HISTORY (Past Twelve Months)

Unit 2 was operated continuously from May 25, 1993 until August 9, 1993, when the unit was taken off line because of steam generator chemistry problems resulting from a condenser tube leak. The unit was repaired and back in service on August 11.

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).

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.

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.

Unit 2 was returned to power on April 19, 1994.

Unit 2 tripped on April 23, 1994, 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.

Unit 2 turbine was shut down and reactor power reduced to Mode 2 on July 9 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.

Unit 2 was shut down on July 14 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.

The unit was restarted and placed on line on July 15, 1994. (IR 94-15)

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 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.

Subsequently, St Lucie was dropped from the NRC management list of good performers in ##### late June 1994. St Lucie had been on this list since #####.

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
	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 major licensee review of corrective action and communication procedures promises to streamline the identification and resolution of adverse plant conditions.

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 procedure 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.

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 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 general 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 of exterior equipment and of equipment that can be reached by chlorides via the ventilation systems 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.

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, SNPO) Six shift rotation,
8-hour shifts: (NPO, ANPO) Five
shift rotation, 8-hour shifts.

Number of SROs: 27 active/17 inactive* / 44 total
Number of ROs: 31 active/1 inactive/ 32 total
Total Licensed Operators: 58 active/18 inactive/ 76 total

* 3 SROs hold inactive SROs and perform RO duties.

4.2 WORK FORCE (8/94)

	<u>FPL</u>	<u>Contractor</u>
Plant personnel (excluding disciplines below)	694	122
Training	62	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 ROs passed and 12 of 12 SROs passed. Three of the ROs failed the written exam and one also failed the JPMs. The program was rated satisfactory. Requalification exams are scheduled for the last quarter of 1994.

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 3 years. Three 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) (6/8/94)

<u>Division</u>	<u>Pre 93</u>	<u>Total</u>	<u>Change from Last Report</u>
DRP	6	30	+12
DRS	0	10	+6
DRSS	<u>0</u>	<u>2</u>	<u>-3</u>
Totals	6	42	+15

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

5.2 MAJOR INSPECTIONS

<u>IR-No.</u>	<u>Date</u>	<u>Type</u>
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

June 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.

-The plant continues to perform well. The latest SALP evaluation gave had ratings of 1 in all categories. St. Lucie received another "good performer" letter from the NRC.

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 inattentiveness	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.

SLSR 694C.WP

REGION II

ATLANTA, GEORGIA

PLANT STATUS REPORT

ST. LUCIE

June, 1994

FF/43

~~470-3120141~~ 23AP

PLANT STATUS REPORT FOR ST. LUCIE (06/94)

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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
 H. F. Buchanan (Hank) - Health Physics Supervisor
 R. E. Dawson (Bob) - Maintenance Manager
 L. W. Bladow (Wes) - Nuclear Assurance Manager
 H. L. Fagley (Herman) - Construction Services Manager
 P. L. Fincher (Pat) - Training Manager
 R. J. Frechette (Bob) - Chemistry Supervisor
 D. J. Denver (Dan) - Site Engineering Manager
 L. L. McLaughlin (Lamar) - Licensing Manager
 J. Scarola (Jim) - Operations Manager
 C. A. Pell (Ash) - Services Manager
 D. H. West (Dan) - Technical Manager
 J. A. West (Jeff) - Operations Supervisor
 W. L. Parks (Bill) - Reactor Engineering Supervisor

1.3 NRC STAFF

REGION II, Atlanta, GA:

S. D. Ebner (Stew), Regional Administrator, (404) 331-5500
 E. W. Merschoff (Ellis), Acting Deputy Regional Administrator
 (404) 331-5610
 J. R. Johnson (Jon), Acting Director DRP, (404) 331-5623
 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:

S. A. Elrod (Steve), Senior Resident Inspector, (407) 464-7822
 M. S. Miller (Mark), Resident Inspector, (407) 464-7822

NRR:

- S. A. Varga (Steven), Director, Division of Reactor Projects-I/II,
(301) 504-1403
- G. C. Lainas (Gus), Assistant Director for Region II Reactors,
(301) 504-1453
- H. N. Berkow (Herb), Director, Project Directorate II-2,
(301) 504-1485
- J. A. Norris (Jan), Senior Project Manager, Project
Directorate II-2, (301) 504-1483

AEOD:

- S. Israel (Sandy), Reactor Operations Analysis Branch,
(301) 492-4437

1.4 LICENSE INFORMATION

	<u>Unit 1</u>	<u>Unit 2</u>
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

<u>Description</u>	<u>Units 1 and 2</u>
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 life span possible. Presently, initial planning is in progress 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. This program continues to be evaluated.

Due to different design and construction characteristics, Unit 2 RPV life expectancy exceeds 60 years.

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 are routinely tested for four-hour DC load profiles. 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 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 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 canals were 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 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.

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. Both items are scheduled to be closed in 1994. The next EP 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, 1993. 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 (6/9/94)

Unit 1 is in Mode 2 following a return to power after a reactor trip on June 7.

Unit 2 is in day 41 of power operation following startup from the Cycle 8 refueling outage on April 26.

Availability Factors:

	<u>Unit 1</u>	<u>Unit 2</u>
1991	81.0	100.0
1992	96.5	75.2
1993	74.0	71.8
1994 (through 4/94)	94.3	39.6
Cumulative (through 4/94)	77.0	81.9

1.8.1 UNIT 1 OPERATING HISTORY (Past Twelve Months)

Unit 1 was returned to power on June 22, 1993, following a refueling outage.

Control Element Assembly #3 dropped during exercising on August 26, 1993. It was promptly recovered.

On September 18 and again on September 20 and September 22, 1993, Unit 1 was manually tripped (from 75, 63, and 11% power) due to jellyfish clogging the intake travelling screens, which required immediately stopping the affected circulating water pumps. Unit 1 operated at various reduced power levels for about two weeks due to the unusual numbers of jellyfish.

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, 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.

The unit was returned to power on April 1; however, the unit tripped 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 and operated continuously until June 6, when the unit tripped 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 approximate 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.

1.8.2 UNIT 2 OPERATING HISTORY (Past Twelve Months)

Unit 2 was operated continuously from May 25, 1993 until August 9, 1993, when the unit was taken off line because of steam generator chemistry problems resulting from a condenser tube leak. The unit was repaired and back in service on August 11.

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).

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.

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.

Unit 2 was returned to power on April 19, 1994.

Unit 2 tripped on April 23, 1994, 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, 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 for October 1, 1994.

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.

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
	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 major licensee review of corrective action and communication procedures promises to streamline the identification and resolution of adverse plant conditions.

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.

Management continues to make conservative decisions regarding plant operations. 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 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 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 general 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 of exterior equipment and of equipment that can be reached by chlorides via the ventilation systems 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 Union 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: None this period

3.2 ENFORCEMENT STATUS/HISTORY (Past 12 Months)

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

PART 4 - STAFFING AND TRAINING

4.1 OPERATIONS STAFF - OVERALL (2/94)

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

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

Number of SROs: 27 active/17 inactive*
Number of ROs: 31 active/1 inactive
Total Licensed Operators: 58 active/18 inactive

* 3 SROs hold inactive SROs and perform RO duties.

4.2 WORK FORCE (3/94)

	<u>FPL</u>	<u>Contractor</u>
Plant personnel (excluding disciplines below)	708	245
Training	62	0
Quality Assurance	42	0
Materials Management	46	0
Security	11	120
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 ROs passed and 12 of 12 SROs passed. Three of the ROs failed the written exam and one also failed the JPMs. The program was rated satisfactory.

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.

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.

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 3 years. Three 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) (6/8/94)

<u>Division</u>	<u>Pre 93</u>	<u>Total</u>	<u>Change from Last Report</u>
DRP	6	30	+12
DRS	0	10	+6
DRSS	<u>0</u>	<u>2</u>	<u>-3</u>
Totals	6	42	+15

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

5.2 MAJOR INSPECTIONS

<u>IR-No.</u>	<u>Date</u>	<u>Type</u>
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	MOI (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

June 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.

-The plant continues to perform well. The latest SALP evaluation gave had ratings of 1 in all categories. St. Lucie received another "good performer" letter from the NRC.

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