March 22, 1995

MEMORANDUM TO: Ellis W. Merschoff, Director
Division of Reactor Projects (DRP)

Orig signed by David M. Verrelli

FROM: David M. Verrelli, Chief
Reactor Projects, Branch 2, DRP

SUBJECT: PLANT PERFORMANCE REVIEW

A Plant Performance Review for Branch 2 Plants was held on March 16, 1995. A list of participants is attached as Attachment 1.

For this review, the Senior Resident Inspector or his representative was chief spokesperson for integrating the results and assessment of performance. The Site Issues Matrix was used to identify any trends in licensee performance. A Prado chart of the Issues Matrix for each site is included as Attachement 2. Other issues discussed included recent inspection findings, planned inspections and future licensee actions which would necessitate changes to the Master Inspection Plan.

North Anna

The last SALP period ended on December 24, 1994. During the past three months there has been no noted decline in performance in any of the four SALP Category 1 functional areas. Since the end of the SALP period the site declared a NOUE on March 1, 1995, due to loss of the Security System Uninterruptible Power Supply and a Notice of Enforcement Discretion was granted on February 3, 1995, when industry identified the potential for loss of one train of the Solid State Protection System. In both cases, the licensee demonstrated prompt response. It was the consensus of the participants that VEPCO conducts thorough self-assessments and has a low threshold for identifying safety issues. Further, no adverse effect in the Engineering area was noted even though routine contractor support has been essentially eliminated over the past year. No changes to the MIP are recommended. For the period March 20 through May 12, a Resident Inspector from Surry (Tingen) will be detailed to North Anna to act as the Senior Resident Inspector while McWhorter is on rotational assignment to the Office of the Chairman.

Surry

The last SALP ended January 21, 1995, and there have been no significant events during the following two months which would indicate a change in performance. As indicated in that SALP, although the Maintenance area was considered good, major challenges include human performance and equipment aging problems. Thus, we recommend that the MIP be revised to add as Regional Initiatives, planned inspection effort in Maintenance Observations (IP 62703) and BOP inspections (IP 71500). This would reduce the Core hours for a N+1

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plant. In addition, Surry will begin additional construction and transfer of spent fuel to their Independent Spent Fuel Storage Installation. Thus, appropriate inspections should be added to the MIP; Construction (IP 60849); Security (IP 81001); Loading, Transfer, Surveillance and Direct Radiation (IP 60846). It is noted that the current ROI 0713, "Independent Spent Fuel Storage Installation and Review Program," would require inspection for all transfers. At Vepco's estimate of 1½-2 weeks per transfer and four-to-six transfers during the next SALP cycle, we believe these total hours are excessive. The ROI should be revised: ACTION: DRSS and DRP Branch Chiefs. MIPs change request forms will be forwarded separately.

Turkey Point

Turkey Point has performed well over the last nine months, with no major indications of change in performance. Currently staffed at N+1, to program resident inspector inspection efforts for a Category 1 performer we plan to place a Resident Inspector on rotational assignment to the Headquarters Duty Officer Staff for a period of six months beginning April 1, 1995 and a second Resident has been be providing assistance to the Resident Staff at Watts Bar.

The major inspection effort at Turkey Point for the future includes the initiation of our Service Water Inspection (reduced scope) and a Headquarters Audit of seismic issues (SI-46). This latter effort will entail a team visit to Corporate for a week and on-site for a week. Region II should assign a Civil Engineer to this team. ACTION: DRS, identify inspector. No changes to the MIP are recommended.

St. Lucie

After an unusually high number of reactor trips between November 1993 and June 1994, St. Lucie has performed well. The licensee has focused management attention to onsite activities: operations is taking more of a leadership role in acceptability of corrective actions: and all non conformance reporting has been consolidated into one system. There are no major efforts scheduled for St. Lucie. None are recommended.

Crystal River

A special Plant Performance Review for Crystal River was performed on January 10, 1995, and the results were presented to the licensee at a Management Meeting conducted on March 1, 1995. The staff concludes there is a definite decline in performance at Crystal River particularly in the Engineering functional area. The licensee conducted a performance review by a Management Review Panel, and found our concerns to be valid and developed a corrective action plan which was submitted to the NRC by letter dated March 10, 1995. The Staff should develop an Inspection Plan to be implemented for Crystal River. This should include inspection of the licensee's Action Plan at appropriate milestones and assessment of its effectiveness. Also included should be a schedule for resolution of outstanding technical issues such as Service Water operability, setpoint methodology, Makeup Tank, and BWST issues. This plan should be developed by March 24, 1995.

Attachments: As stated (2)

E. Merschoff 3

cc w/atts:
S. Ebneter
L. Reyes
J. Jaudon
J. Stohr
J. Johnson
A. Gibson
B. Mallett
T. Peebles
W. Cline
C. Casto
A. Belisle
K. Landis
M. Branch
R. McWhorter
S. Tingen
T. Johnson
R. Butcher
R. Prevatte
L. Garner
R. Schin

SEND TO PUBLIC DOCUMENT ROOM?	YES	NO				
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NAME	DVerrelli					
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COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: G:\PLTPERF.REV

Division of Reactor Projects
Branch 2
Plant Performance Review
March 16, 1995

List of Participants

ATTENDEES

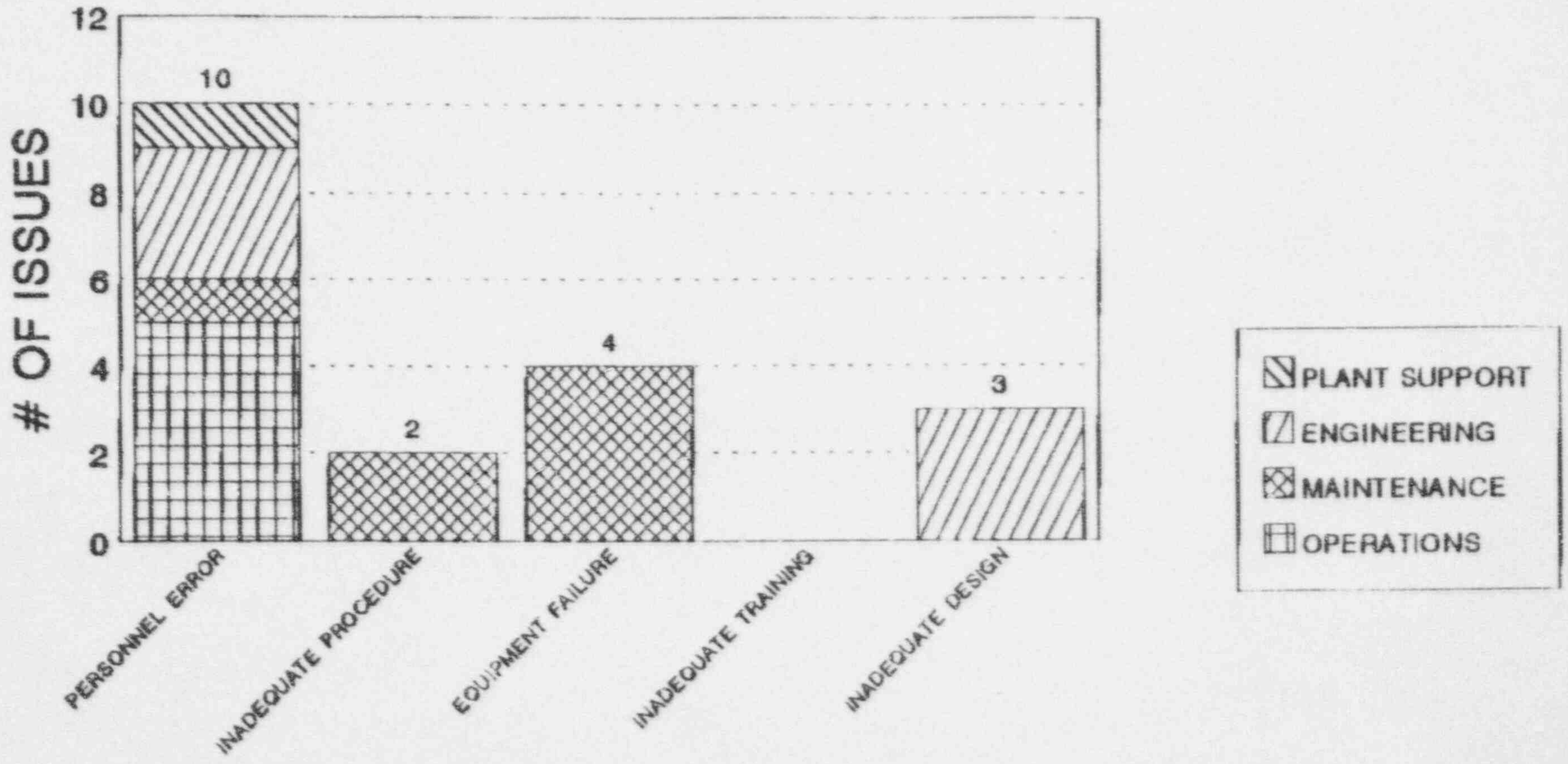
E. Merschoff, DRP
R. Cooper, Region I
B. Mallett, DRSS
J. Johnson, DRP
T. Peebles, DRS
C. Casto, DRS
D. McGuire, DRSS
W. Rankin, DRSS
T. Decker, DRSS
K. Landis, DRP
T. Johnson, DRP
R. Butcher, DRP
M. Miller, DRP
M. Branch, DRP
D. Taylor, DRP
L. Garner, DRP
R. Schin, DRP
L. Raghavan, NRR

BY PHONE

G. Belisle, DRP
J. Norris, NRR
R. Prevatte, DRP
R. Croteau, NRR
B. Buckley, NRR

ATTACHMENT 1

NORTH ANNA
ISSUES BY ROOT CAUSE AND SALP AREA



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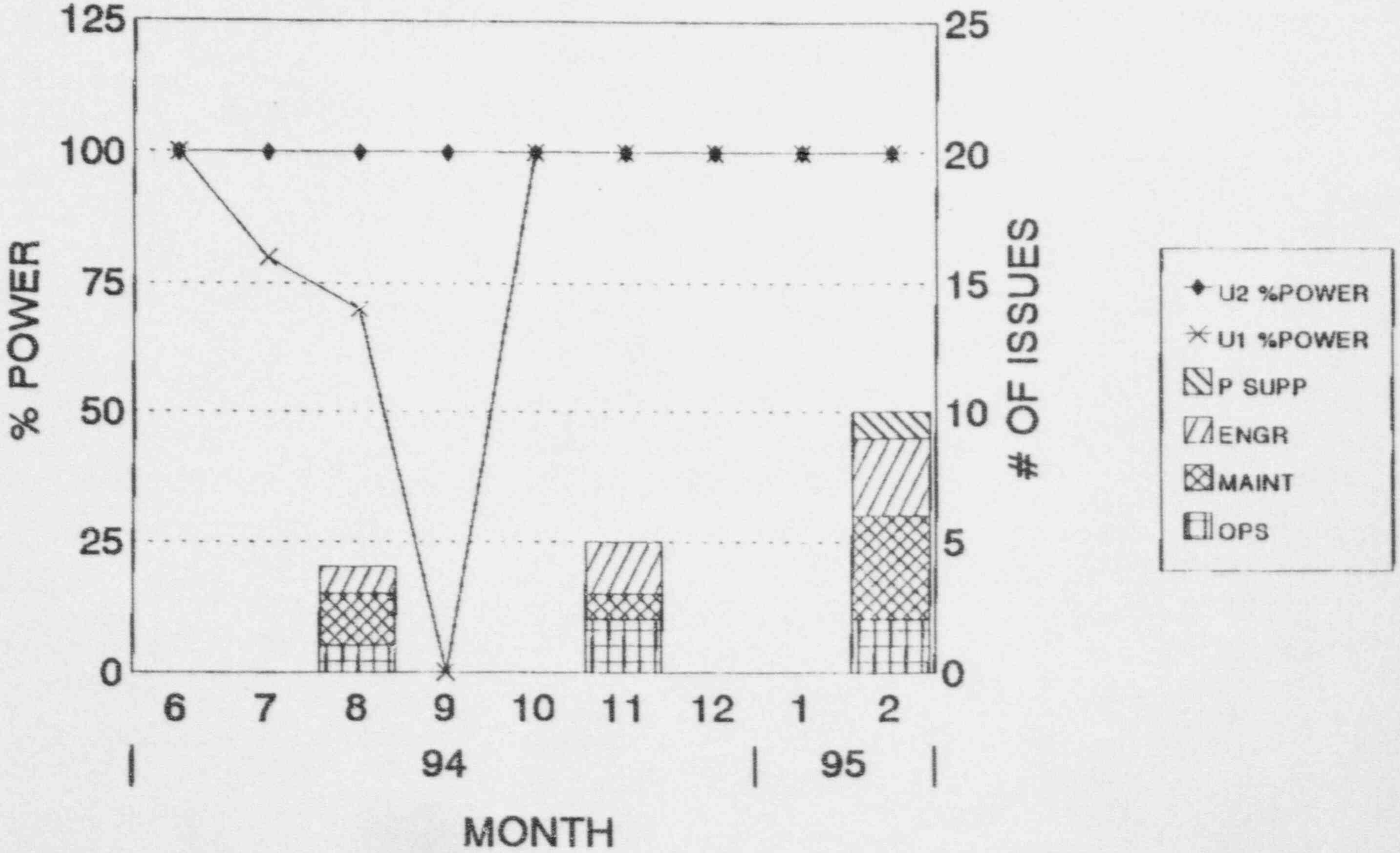
ENGINEERING	3	0	0	0	3
MAINTENANCE	1	2	4	0	0
OPERATIONS	5	0	0	0	0

6/94 TO 2/95

ATTACHMENT 2

NORTH ANNA

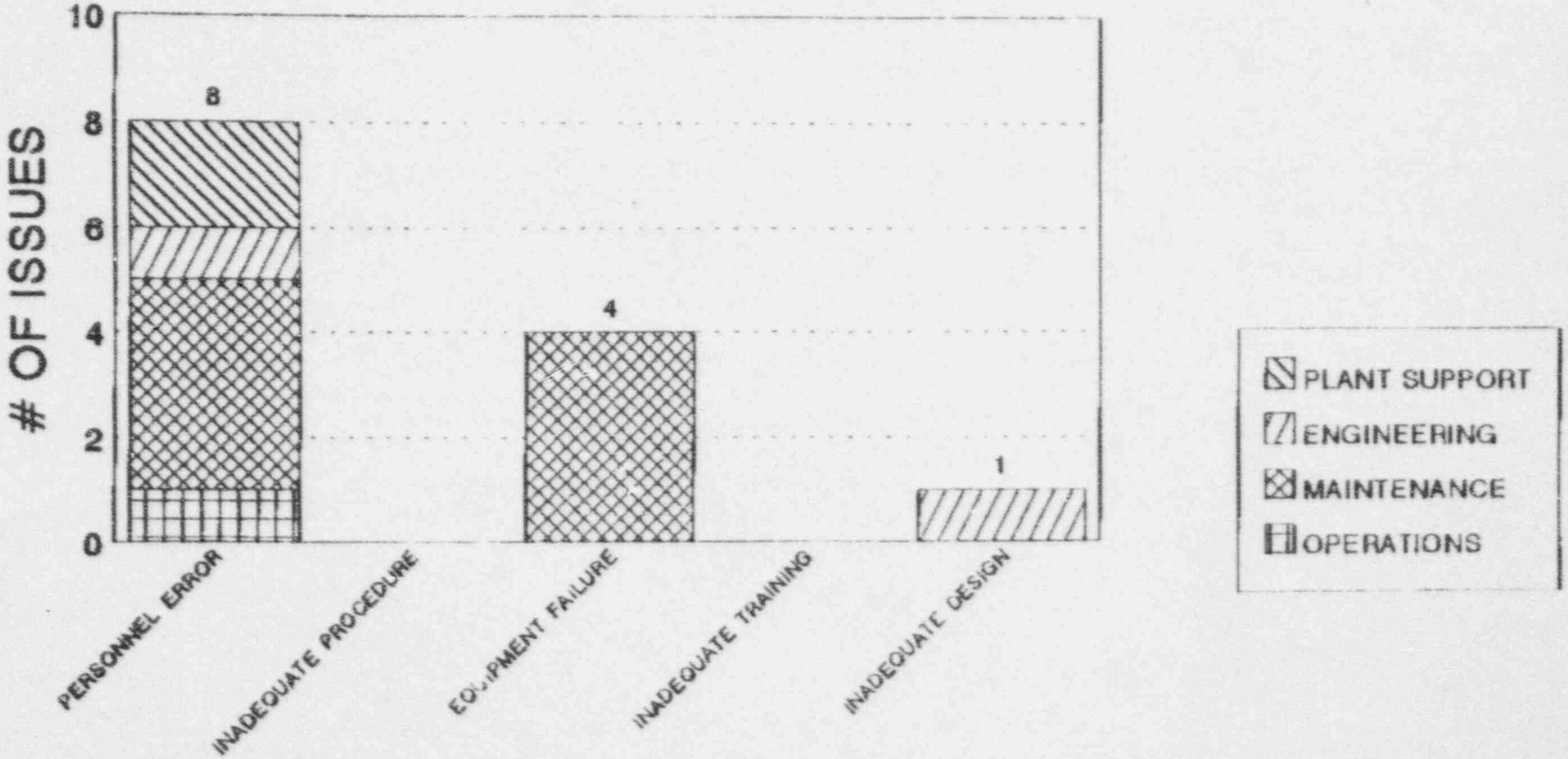
POWER and # of ISSUES vs TIME



6/94 TO 2/95

SURRY

ISSUES BY ROOT CAUSE AND SALP AREA

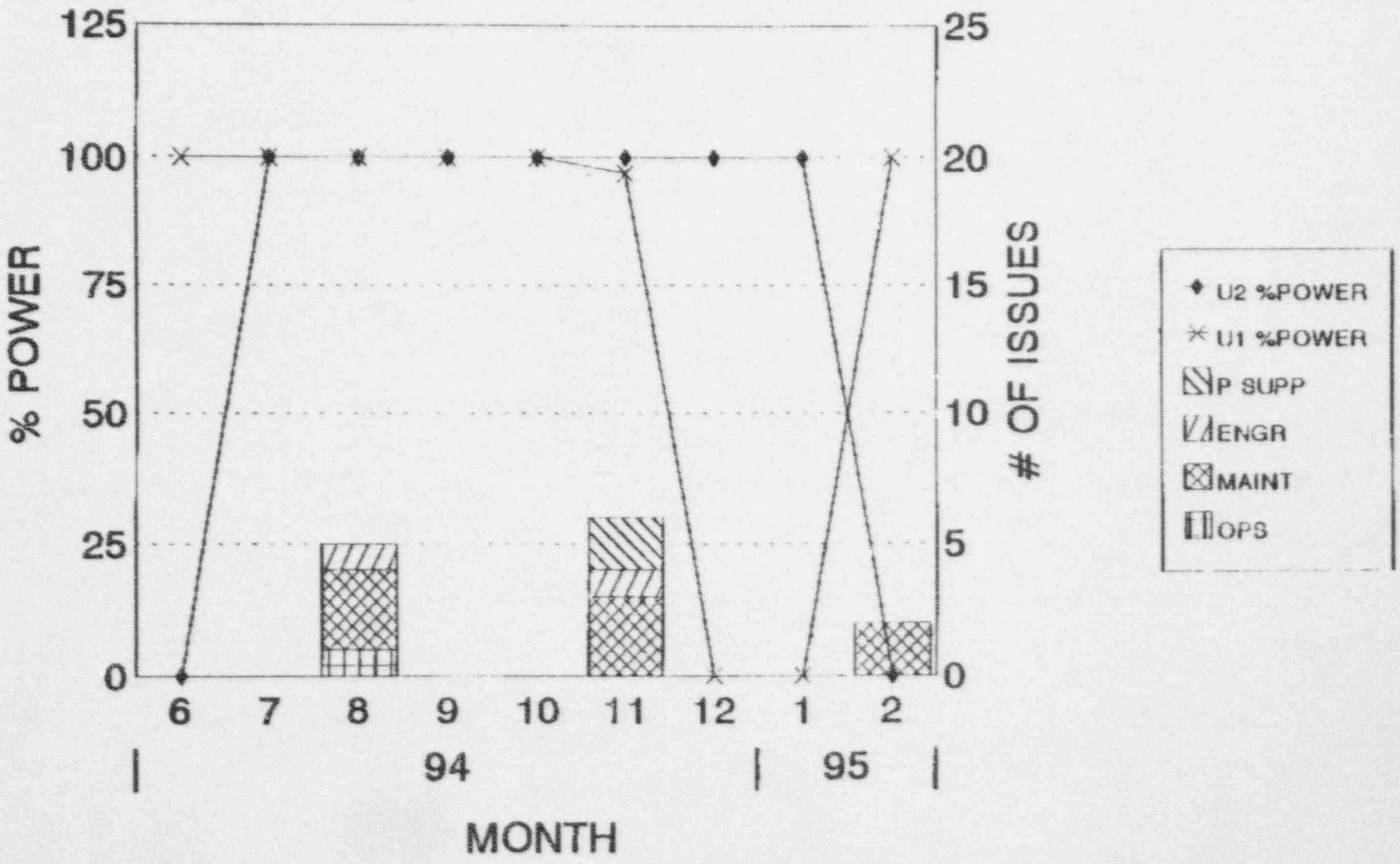


PLANT SUPPORT	2	0	0	0	0
ENGINEERING	1	0	0	0	1
MAINTENANCE	4	0	4	0	0
OPERATIONS	1	0	0	0	0

6/94 TO 2/95

SURRY

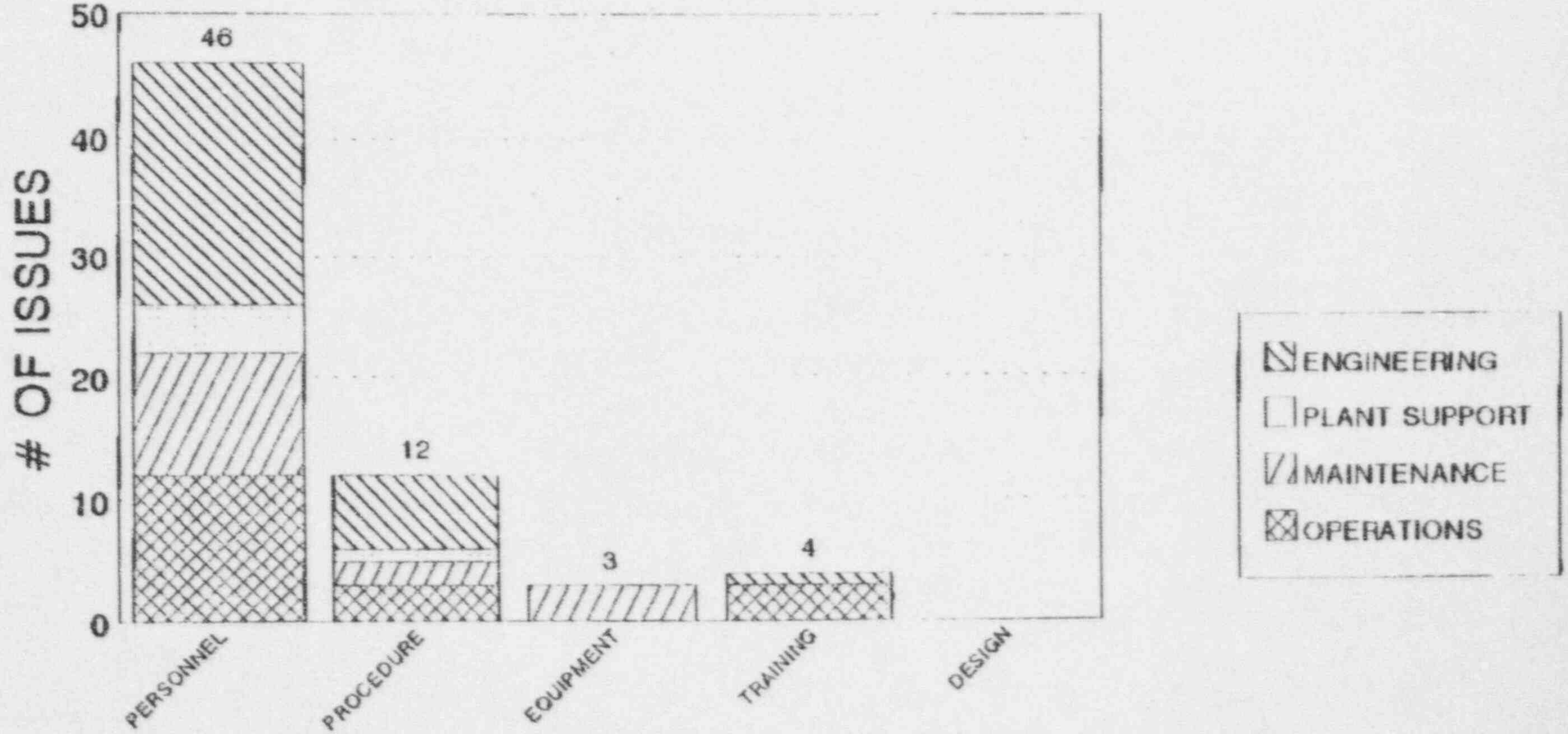
POWER and # of ISSUES vs TIME



6/94 TO 2/95

CRYSTAL RIVER

ISSUES BY ROOT CAUSE AND SALP AREA

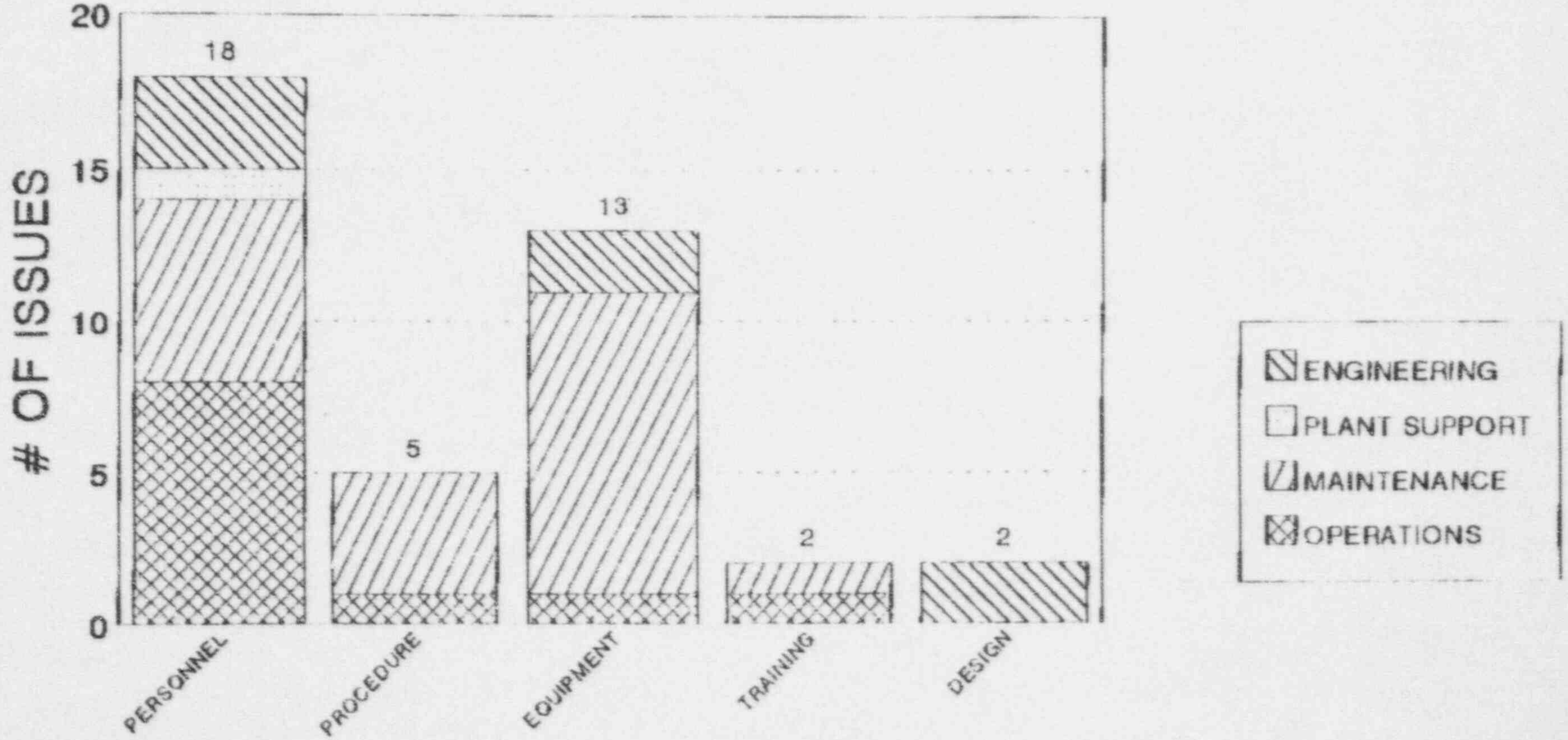


	PERSONNEL	PROCEDURE	EQUIPMENT	TRAINING	DESIGN
ENGINEERING	20	6	0	1	0
PLANT SUPPORT	4	1	0	0	0
MAINTENANCE	10	2	3	0	0
OPERATIONS	12	3	0	3	0

3/94 THRU 2/95

ST. LUCIE

ISSUES BY ROOT CAUSE AND SALP AREA

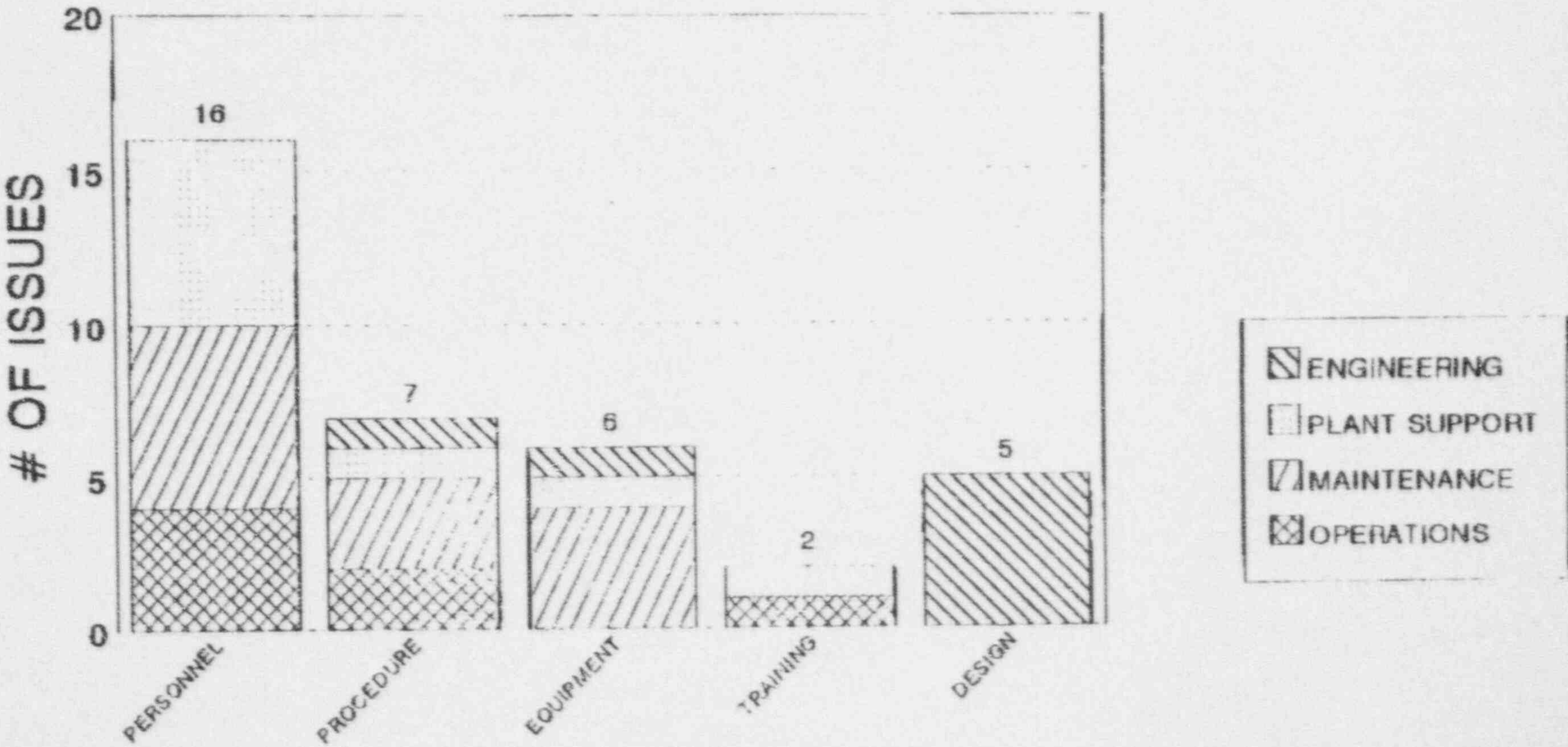


ENGINEERING	3	0	2	0	2
PLANT SUPPORT	1	0	0	0	0
MAINTENANCE	6	4	10	1	0
OPERATIONS	8	1	1	1	0

3/94 THRU 2/95

TURKEY POINT

ISSUES BY ROOT CAUSE AND SALP AREA



ENGINEERING	0	1	1	0	5
PLANT SUPPORT	6	1	1	1	0
MAINTENANCE	6	3	4	0	0
OPERATIONS	4	2	0	1	0

3/94 THRU 2/95

SL-SPPR.395

March 16, 1995

ST LUCIE

Integrated Plant Performance Review

A. Current Plant Status

Unit 1 has been operating at power since March 8, 1995. The unit was returned to power following a short notice outage for pressurizer code safety valve replacement. The next refueling outage is scheduled for April 4, 1996.

Unit 2 has been operating at power since February 25, 1995. The unit was returned to power following a reactor trip due to low steam generator water level resulting from a level transmitter failure. The next refueling outage is scheduled for September 25, 1995.

B. Management

The current organization has been effective since September 1, 1994:

C. Plant Performance

The units experience an unusually high number of reactor trips (4) between March 94 and June 94. However, during the past nine months, the units have experienced two reactor trips, two unit shutdowns, one unit off-line for maintenance and one loss of shut down cooling event. Operator performance was good during the trips and shutdowns.

July 8, 1994 - Unit 2 was taken off line (Mode 2) when 2B1 RCP lower oil level indication failed, incorrectly showing leak.

Ju 14, 1994 - Unit 2 was shut down to allow repair of a stuck-closed reactor trip circuit breaker.

October 26,1994 - Automatic trip of Unit 1 due to arc-over from a potential transformer in the switchyard which resulted in a loss of load.

February 21,1995- Automatic trip of Unit 2 when a SG water level transmitter failed high. The failure resulted in a closure of a FRV, starving the SG for water and leading to a trip on SGWL.

February 27,1995- Unit 1 was shut down to replace pressurizer code safety valves, which had been leaking by the seat since restarting from the Unit 1 outage in November.

March 4, 1995 - Unit 1 experienced a loss of shutdown cooling for approximately 14 minutes when a hot leg suction valve to the operating shutdown cooling train closed. Root cause has not been established; however, operator error in manipulating valves is the most likely cause.

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D. Performance Indicators

St. Lucie performance indicators indicate above average performance of both units, with a recent decrease in automatic scrams.

E. Enforcement History

No escalated enforcement in 1993 or 1994.

F. SALP

	Period ended May 1992	Period ended January 1994
Operations	1	1
Maintenance	1	1
Engineering	1	1
Plant Support		1
Rad. Con.	1	
Security	1	
Emerg. Prep.	1	
SA/QV	1	

G. INPO

INPO assessment March 1992 - Category 1
INPO/WANO assessment April 1994
Next INPO assessment scheduled for August-October 1995

H. 1994 Precursor Events None

I. Allegations and DOL Cases

Six allegations are open: one negative performance appraisal; one security guards - insufficient number, drinking, etc.; one fitness for duty - alcohol consumption; one attempt to coverup GL 79-02 bolting discrepancies; one ARMS room door left open and unattended; and one regarding weld repaires on CCW. No DOL cases are open.

J. Attachments

1. Organization Charts
2. Power History Profiles
3. Issues Matrix

REGION II

ATLANTA, GEORGIA

PLANT STATUS REPORT

ST. LUCIE

MARCH, 1995

FF/36

9704070115-23pp

PLANT STATUS REPORT FOR ST. LUCIE (3/95)

TABLE OF CONTENTS

PART 1 - FACILITY DESCRIPTION

1.1 FACILITY/LICENSEE

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

1.2 UTILITY SENIOR MANAGEMENT

CORPORATE:

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

SITE:

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

1.3 NRC STAFF

REGION II, Atlanta, GA:

S. D. Ebneter (Stew), Regional Administrator, (404) 331-5500
L. A. Reyes (Luis), Deputy Regional Administrator (404) 331-5610
B. A. Boger (Bruce), 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:

R. L. Prevatte (Dick), 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
J. A. Zwolinsky (John), Deputy Director, Division of Reactor Projects-I/II, (301) 504-1335
D. B. Matthews, Deputy Director, Project Directorate II-2, (301) 415-1490
J. A. Norris (Jan), Senior Project Manager, Project Directorate II-2, (301) 504-1483

AEOD:

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

1.4 LICENSE INFORMATION

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

1.5 PLANT CHARACTERISTICS

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

1.6 SIGNIFICANT DESIGN INFORMATION

1.6.1 REACTOR INTEGRITY

Reactor Pressure Vessel (RPV)

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

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

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

Reactor Coolant Pressure Boundary

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

1.6.2 REACTOR SHUTDOWN

Reactor Protection System

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

ATWS Protection

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

Remote Shutdown Facilities

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

1.6.3 CORE COOLING

Feedwater System

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

Turbine Bypass/Steam Dump Capacity

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

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

Auxiliary Feedwater System

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

Emergency Core Cooling System

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

Decay Heat Removal

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

1.6.4 CONTAINMENT

Pressure Control/Heat Removal

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

Hydrogen Control

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

1.6.5 ELECTRICAL POWER

Offsite AC

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

Onsite AC

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

DC Power

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

Instrumentation Power

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

Station Blackout Resolution Status

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

1.6.6 SAFETY-RELATED COOLING WATER SYSTEMS

Intake Cooling Water (Service Water)

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

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

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

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

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

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

Closed Cooling Water Systems

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

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

1.6.7 SPENT FUEL STORAGE

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

1.6.8 INSTRUMENT AIR SYSTEM

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

1.6.9 STEAM GENERATORS

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

1.7 EMERGENCY RESPONSE FACILITIES/PREPAREDNESS

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

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

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

- High Frequency Auto-link with other FPL sites and NRC.

- Enhanced 900 MHZ System for site and mobile communications, with radios also in the licensee's EOF and county emergency facility.

- Cellular phones with hardened antennas.

- Hardened Local Government Radio antenna ties.

1.8 PRESENT OPERATIONAL STATUS (3/9/95)

Unit 1 is operating at 100% power and has been operating since a reactor startup on March 8 following a short notice outage for pressurizer code safety valve replacement.

Unit 2 is operating at 100 % power and has been operating since a reactor startup on February 24 following a trip on February 21 due to an instrument failure.

Availability Factors:

	Unit 1	Unit 2
1991	81.0	100.0
1992	96.5	75.2
1993	74.0	71.8
1994	86.8	79.6
1995 (through 1/95)	100.0	100.0
Cumulative (through 1/95)	77.3	83.0

1.8.1 UNIT 1 OPERATING HISTORY (Past Twelve Months from 3/21/95)

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

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

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

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

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

On October 26, the unit tripped from 100 percent power due to a loss of electrical load. This was the result of arc-over in a potential transformer in the switchyard due to salt buildup. The licensee then entered a unit refueling outage, which had been scheduled to begin four days later. The unit was returned to service on November 29.

On February 21, 1995, the unit was removed from service for the replacement of pressurizer code safety valves which had been leaking by the seat since shortly after startup in November, 1994. The unit was returned to service on March 8.

On March 4, 1995, the unit experienced a 14 minute loss of shutdown cooling. The apparent root cause was operator error by a reactor operator placing one loop of SDC in standby. The operator apparently closed the suction valve to the operating, vice standby, pump. The operator in question has denied the error. The licensee is considering disciplinary action and has releived the operator of licensed activities.

1.8.2 UNIT 2 OPERATING HISTORY (Past Twelve Months from 3/21/95)

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

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

indications were the result of Primary Water Stress Corrosion Cracking (PWSCC).

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

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

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

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

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

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

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

On February 21, 1995, the unit tripped as a result of low steam generator water level. The condition was the result of a feedwater regulating valve closure after a steam generator water

level control level transmitter failed high. The transmitter was replaced and the unit was returned to service on February 25.

1.9 OUTAGE SCHEDULE AND STATUS

Unit 1's last refueling outage began on October 26, 1994, and ended on November 29, 1994. Major activities included: refueling; reactor vessel nozzle and flange weld ISI inspection; installation of a permanent cavity seal ring; 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; replacement of a main transformer; modification of containment spray NaOH addition piping; and mechanical, electrical, and I&C systems maintenance.

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

PART 2 - PLANT PERSPECTIVE

2.1 GENERAL PLANT PERSPECTIVE

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

In June 1994, St Lucie was dropped from the NRC management list of good performers after experiencing five unit reactor trips in the first half of [illegible]4.

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 -	1	1	1	1	1	1	1

5/2/92

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

2.3 SELECTED SALP AREA DISCUSSIONS (3/21/95)

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

Plant Operations

Summary of Previous Assesment

Within the current SALP cycle, previous assessments have noted a *potential* decline in Operations' performance. Noted indicators included five reactor trips in the first six months of the cycle. No common root causes were identified. Operator actions with regard to the noted trips were generally good. Two entries into reduced inventory operations during the Unit 2 outage were noted as excellent. Procedural weaknesses which indicated a lack of rigor in the review process were noted, as was the fact that temporary changes to procedures were on the increase (indicating increasing attention to procedural adequacy).

Management activities in response to the increase in operational events was determined to be strong, with an increase in overall focus directed at plant operations. The corrective actions program was enhanced, consolidating tens of programs into one which involves daily management reviews of all documented conditions.

The previous assessments concluded that Operations remained strong in the current period, that management actions were agressive in dealing with identified weaknesses, and that increased attention to procedural adequacy may be warrented.

Last Six Months

The previous six months as shown a sharp decrease in the number of reactor trips, with two having occurred; one due to salt buildup on switchyard components which led to a loss of electrical load on Unit 1, and one due to a level transmitter failure which led to a low steam generator level trip on Unit 2.

Operator Performance

Operator performance has been noted to be good to excellent in evolutions such as post-trip response, startups, mid-loop operations (during the Unit 1 outage), and in the performance of surveillance testing. Several findings have indicated potential weaknesses in attention to detail on the part of operators. They include:

- Failure to sample a SIT within the TS-required time frame. Second occurrance in two years.
- Failure to identify an inoperable LPSI header pressure control board indicator which had been failed in mid-range for approximately two weeks.
- Minor refueling machine errors of omission
- Failure to identify/notify in response to Unit 1 hot leg stratification.
- Potential operator error in valve control manipulation which led to a loss of shutdown cooling on Unit 1.

An issue of a lack of professionalism and of a casual attitude toward EOPs on the part of one individual was identified during operator examinations. The licensee prepared and executed an agressive remediation plan prior to allowing the individual to return to watchstanding duties.

Strengths

Strengths have been identified in the ability of the Operations department to intgrate plant activities. Aspects included multidisciplinary briefings prior to major evolutions (be they operations or maintenance evolutions), and an increased involvement by Operations in the prioritization of maintenance activities.

Operations' management has played a major role in the identification and resolution of prominent problems, including:

- 2B LPSI pump air-binding
- Pressurizer relief valve seat leakage
- Failure to sample SITs following volume additions
- Minimum temperature for criticality discrepancies
- CVCS letdown control anamolies

In these and other cases, Operations has expressed an unwillingness to accept stopgap maintenance measures and has demanded that historically poorly performing systems be made to operate correctly.

Weaknesses

Weaknesses have been identified in annunciator response procedures (several were discrepant either in setpoint reference or in content), corrective actions (a violation resulted from the licensee's failure to recognize the impact of a failure to perform adequate surveillance testing on swing bus components), logkeeping (a violation resulted from the modification, by one shift, of another shift's log entries), and aspects of the Facility Review Group's activities (some members were identified as "going through the motions" of review; however, the Plant General Manager was consistently cited as a strong presence who articulated expectations and kept members on track).

Conclusion

On balance, Operations continues to be strong at St. Lucie. The licensee continues to be agressive in the identification and resolution of operational problems. In the last six months, operations has shown a new involvement in maintenance prioritization which has increased the safety perspective applied to maintenance activities.

Maintenance/Surveillance

Summary of Previous Assesment

Maintenance was assessed as category 1 in the previous SALP. The previous assessments made during the current SALP cycle indicated that the performance level of maintenance activities had not abated. Strong performance had been noted in the support of the Unit 2 outage, and housekeeping and plant preservation activities were deemed good.

Last Six Months

During the past six months, twenty-seven maintenance activities were observed in varying levels of depth. Two violations were cited; one involving the misuse of an unreviewed vendor technical manual and one involving a failure to perform an adequate independent verification of landed leads. Workers were generally found to be well-trained, conscientious, and skilled.

Twenty-four surveillance activities were observed. No violations or major weaknesses were identified as a result.

Strengths

The Unit 1 outage was considered a major strength. The outage was conducted in thirty-five days, three

days ahead of schedule, without a safety-significant reduction in work scope.

The licensee developed and implemented a Critical Maintenance Management program for the performance of maintenance within TS ASs. Maintenance activities performed under this program have been observed and found to be well-planned and executed and have been performed after assessing the increased risk associated with the activity.

The licensee's predictive maintenance program has continued to provide early indications of impending failures. Most recently, the organization identified an unsatisfactory lug in cabling supplying one phase of a CEA MG.

Weaknesses

Isolated weaknesses have been identified both by the NRC and the licensee's QA organization. They include:

- A failure to properly incorporate changes into VTMs. Required FRG reviews were not performed.
- A failure to adequately define and perform independent verifications properly.
- A failure to properly implement elements of the site's welding program. This was identified by QA and resulted in the Maintenance Manager issuing a stop work order, which was in place for one week, while concerns were addressed.

Conclusion

Maintenance continues to be performed at superior levels. Planning and execution has improved through extensive planning efforts. The addition of the Critical Maintenance Management program has enhanced on-line maintenance by requiring extensive review and planning prior to work. Surveillances continue to be performed well.

Engineering

Summary of Previous Assesment

The previous assessments for this SALP cycle concluded that engineering was generally strong. Good support of the Unit 2 outage was noted, as was good QA with respect to fuel fabrication and receipt inspection. Potential problems were noted in the area of vendor technical manuals.

Last Six Months

The noted concerns with respect to VTMs were, in part, validated in the maintenance area, where a violation resulted; however, the violation was not reflective of a failure on the part of engineering. Good support to the Unit 1 outage was noted, with engineering personnel assuming pivotal roles in the management of the outage. One NCV was identified, relating to the design of NaOH supply piping, however, the problem had existed since shortly after construction and was appropriately addressed.

Five plant modifications and several safety evaluations were reviewed and were generally found to be thorough and correct. The licensee's program for the control of containment coatings was reviewed and found to be satisfactory. Engineering involvement has been evident in each major plant challenge in the last six months, including:

- Apparent air-binding of the 2B LPSI pump
- 1A LPSI pump relief valve lift
- Unit 1 Pressurizer relief valve seat leakage
- Post-event reviews of loss of Unit 1 SDC
- Unit 1 RWT leak repairs

Conclusion

Engineering continues to perform well. No weaknesses have been identified in this functional area.

Plant Support

Radiological Controls

Previous assessments this SALP cycle indicated an effective program. Inspections this period indicate good control of internal/external exposure and containment during outages. ALARA initiatives were noted; robotics, submersibles, and telemetry. The licensee was noted to be ahead of most of the region in the use of cameras, video and wireless communications.

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

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

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

4.2 WORK FORCE (8/94)

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

Materials Management	46	0
Security	11	122
Site Engineering	42	0

4.3 OPERATOR QUALIFICATION/REQUALIFICATION PROGRAM (Past Two Years)

4.3.1 REQUALIFICATION PROGRAM

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

4.3.2 INITIAL EXAMS

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

4.3.3 GENERIC FUNDAMENTAL EXAM

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

4.4 PLANT SIMULATOR

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

4.5 INPO ACCREDITATION

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

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

PART 5 - INSPECTION ACTIVITIES

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

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

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

5.2 MAJOR INSPECTIONS

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

5.3 PLANNED TEAM INSPECTIONS

None

5.4 INFREQUENT INSPECTION PROCEDURE STATUS

No core modules are overdue at this time.

5.5 SIMS STATUS - OPEN TMI ITEMS

There are no cpen TMI items.

ATTACHMENT 3

NRR OPERATING REACTOR ASSESSMENT

NRR ASSESSMENT FOR ST. LUCIE

October 1994

CURRENT ISSUES

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

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

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

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

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