UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

January 29, 2003

Florida Power and Light Company
ATTN: Mr. J. A. Stall, Senior Vice President
Nuclear and Chief Nuclear Officer
P. O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: ST. LUCIE NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 50-335/02-04 AND 50-389/02-04

Dear Mr. Stall:

On January 4, 2002, the US Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Units 1 and 2. The enclosed integrated inspection report documents the inspection findings which were discussed on January 3, 2003, with Mr. Don Jernigan and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC identified finding and one self-revealing finding of very low safety significance (Green). These two findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these two findings as non-cited violations (NCVs), in accordance with Section VI.A of the NRC's Enforcement Policy. If you contest any NCV in this report, you should provide a response, within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at the St. Lucie facility.

Since the terrorist attacks on September 11, 2001, the USNRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The USNRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) '02, and the remaining inspections are scheduled for completion in CY '03. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the

Office of Nuclear Security and Incident Response. For CY ‘03, the USNRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the USNRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC’s document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Joel T. Munday, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 50-335/02-04, 50-389/02-04
w/Attachment - Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-335, 50-389
License Nos.:	DPR-67, NPF-16
Report Nos.:	50-335/02-04, 50-389/02-04
Licensee:	Florida Power & Light Company (FPL)
Facility:	St. Lucie Nuclear Plant, Units 1 & 2
Location:	6351 South Ocean Drive Jensen Beach, FL 34957
Dates:	September 29 through January 4, 2003
Inspectors:	T. Ross, Senior Resident Inspector S. Ninh, Senior Project Engineer (Sections 4OA2, 4OA3) S. Rudisail, Project Engineer S. Sanchez, Resident Inspector (Crystal River) S. Stewart, Senior Resident Inspector (Crystal River) S. Vias, Senior Reactor Inspector (Sections 1R08 and 4OA5) J. Wallo, Senior Physical Security Inspector (Section 4OA5.3) K. Davis, Physical Security Inspector (Section 4OA5.3)
Approved by:	Joel Munday, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000335/2002-004, 05000389/2002-004; Florida Power & Light; 09/29/2002-01/04/2003; St. Lucie Nuclear Plant, Units 1 & 2; Refueling and Outage Activities, Event Followup.

The report covered a three month period of inspection by the St. Lucie senior resident inspector, resident inspectors from the Crystal River site, and several region based inspectors. Two Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. Inspector Identified Findings and Self-revealing Findings

Cornerstone: N/A

Green. Inadequate management and supervisory awareness of the administrative requirements for controlling overtime resulted in multiple instances of plant personnel exceeding the overtime limits during the unit 1 outage without proper authorization and documentation.

A non-cited violation of TS 6.2.2.f was identified by the NRC. This finding is greater than minor because if left uncorrected it could become a more significant safety concern due to excessive fatigue by personnel performing safety-related activities. The safety significance of the finding was very low because there were no specific performance deficiencies associated with the individuals during the time they exceeded the established overtime limits. (Section 1R20).

Cornerstone: Barrier Integrity

Green. Inadequate door seal evaluation during maintenance activities resulted in both trains of Unit 2 control room emergency air cleanup system (CREACS) inoperable for a time longer than 24 hours.

A self-revealing non-cited violation of Technical Specification 3.7.7 Action b was identified. This finding is greater than minor because it affected the barrier integrity cornerstone objective of providing reasonable assurance that physical design barriers provide protection from radionuclide releases caused by accidents or events. The finding is of very low safety significance because CREACS was able to maintain a positive pressure during the affected period and the control room envelope remained operable with respect to its design bases function of maintaining operator dose within general design criterion (GDC) 19. (Section 4OA3.2).

B. Licensee Identified Violations

None

Report Details

Summary of Plant Status

Unit 1 began the report period shutdown for its eighteenth refueling outage (SL1-18). The unit was returned to service and achieved full power operation on October 27, 2002. A manual reactor trip from 7% power occurred on October 24, due to the loss of main feedwater during startup.

Unit 2 operated at essentially full power for the entire report period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity (Reactor - R)

1R04 Equipment Alignment

.1 Partial Equipment Walkdowns

a. Inspection Scope

The inspectors conducted partial alignment verifications of the safety related systems listed below to review the operability of required redundant trains or backup systems while the other trains were inoperable or out of service. These inspections included reviews of plant lineup procedures, operating procedures, and piping and instrumentation drawings which were compared with observed equipment configurations to identify any discrepancies that could affect operability of the redundant train or backup system.

- 1B Emergency Diesel Generator (EDG)
- 1A Component Cooling Water system

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Inspections

a. Inspection Scope

The inspectors conducted tours of the fire areas and/or witnessed associated activities listed below to verify whether they conformed with Administrative Procedure AP-1800022, Fire Protection Plan. The inspectors specifically examined any transient combustibles in the areas and any ongoing hot work or other potential ignition sources. The inspectors also assessed whether the material condition, operational status, and operational lineup of fire protection systems, equipment and features were in accordance with the Fire Protection Plan. Furthermore, the inspectors evaluated the use of any compensatory measures being performed in accordance with the licensee's procedures and Fire Protection Plan.

- Hot work activities during Unit 2 Control Element Drive Mechanism Control System (CEDMCS) air conditioning and ventilation modification
- Hot work activities in the turbine building during SL1-18
- Unit 2 cable spreading room (CSR) and vital switchgear room during CEDMCS modification
- 1A EDG fire detection system compensatory measures
- Unit 1 B train vital switchgear room
- Unit 1 Containment during SL1-18

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

During the week of December 16, the inspectors reviewed the UFSAR to determine risk significant areas for both units and to verify flood mitigation plans and equipment were consistent with the design requirements and the risk analysis assumptions. Plant areas containing risk significant systems or components which were susceptible to either internal or external flooding were examined to evaluate the condition of flood protection equipment. The following areas were examined:

- Unit 1 and Unit 2 ECCS rooms

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI)

.1 Unit 1 Inservice Inspections

a. Inspection Scope (7111108)

The inspectors observed in-process ISI work activities and reviewed selected ISI records. The observations and records were compared to the Technical Specifications (TS) and the applicable Code (ASME Boiler and Pressure Vessel Code, Sections V and XI, 1989 Edition, with no Addenda) to verify compliance.

The inspectors observed inspection activities and reviewed the documentation for the following ISI activities:

- Ultrasonic (UT) examinations in the Flow Accelerated Corrosion (FAC) Program [Loc. 28 Component 14HD39-P-6-13]
- Radiographic (RT) examination film, [Dwg. SI-N-16, welds SI-515-2000, SI-113-2000, Unit 2]

- UT examination of weld BF-14-2-SW-1 (pipe to elbow)
- Automated Testing of one PSA-3 snubber, Hanger 1-056, SN:116
- Remote Visual (VT) examination of the reactor vessel head to Control Element Drive Mechanism (CEDM) nozzles (see Section 4OA5)
- Automated UT examinations of the ‘J’ welds between the CEDMs nozzles and the reactor vessel (see Section 4OA5)
- Bolted Joint Leakage Program

Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

On December 5, 2002, inspectors observed and assessed licensed operator actions on the simulator in response to a large break loss of coolant accident scenario that also involved the failure of numerous critical safety equipment. The inspector specifically evaluated the following attributes related to operating crew performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of Emergency Operating Procedures and Emergency Plan Implementing Procedures
- Control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by Operations supervision, including ability to identify and implement appropriate TS actions, regulatory reporting requirements, and emergency plan actions and notifications
- Effectiveness of the post training critique

The inspectors also met with the Licensed Operator Requalification (LOR) training supervisor to discuss the disposition of the biennial simulator evaluation and written exam results. Furthermore, on December 12, 2002, the inspectors monitored conduct of a biennial written exam.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

.1 Routine Inspection

a. Inspection Scope

The inspectors evaluated the effectiveness of licensee efforts in accordance with Administrative Procedure ADM-17.08, Implementation of 10 CFR 50.65, The Maintenance Rule, and 10CFR50.65, to address equipment problems associated with the systems listed below. The inspectors' efforts focused on maintenance rule scoping, characterization of the failed components, risk significance, determination of a(1) classification, corrective actions, and the appropriateness of established performance goals and monitoring criteria. The inspectors also attended applicable expert panel meetings, interviewed responsible engineers, and observed some of the corrective maintenance activities. Furthermore, the inspectors verified whether equipment problems were being identified at the appropriate level and entered into the corrective action program.

- Uni 1 Vital Instrument Air Emergency Cooling System
- Unit 1 Vital 125 VDC Batteries
- Condition Report (CR) 02-2650, Unit 1 4.16 kV 1B AFW pump breaker

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the following online maintenance activities to evaluate the effectiveness of licensee scheduling, configuration control, and management of online risk in accordance with applicable program procedures such as ADM 17.16, Implementation of the Configuration Risk Management Program. The inspectors also examined whether appropriate contingencies were taken to reduce risk and minimize unavailability, and that emergent work activities were properly planned per ADM-10.03, Work Week Management. The inspectors confirmed that problems with maintenance, risk assessments and emergent work were identified and appropriately addressed by the corrective action program.

- 1A CCW Pump and 1A/B Instrument Air (IA) compressors out of service (OOS)
- 1B EDG, 1A/B IA compressors, and various Unit 1 vital ventilation systems OOS
- Red shutdown assessment due to 1B Auxiliary Feedwater Pump breaker failure

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions And Events

a. Inspection Scope

De-energization of Unit 1 Vital 4KV Bus During SL1-18

On October 18, the inspectors observed licensee planning, preparations, pre-evolution brief, execution and restoration for de-energizing and re-energizing the 1B3 vital 4KVAC bus during Mode 5 of SL1-18 with reactor vessel water level at the flange. The inspectors verified plant parameters remained stable while only one shutdown cooling train was operable and in operation. Furthermore, the inspectors discussed the evolution with a member of the Risk Assessment Team and site management prior to the licensee entering a “Red” condition per their Safe Shutdown Assessment guidance and entering the one hour TS action statement 3.4.1.4.1.a.

Unit 2 CEDMCS Room High Humidity Conditions

During December 12 thru 14, the inspectors assessed the licensee’s response to a degraded condition involving high humidity conditions in the Unit 2 CEDMCS room that resulted in multiple, repetitive, unexpected alarms and an electrically unmoveable control element assembly (CEA). The inspectors evaluated operator actions pursuant to applicable TS and abnormal operating procedures, such as ONOP-2-0110030, CEA Off-Normal Operation and Alignment. The inspectors also examined plant conditions and indicated parameters; reviewed operator logs; walked down the CEDMCS room; and, interviewed responsible engineering and Instrumentation and Control personnel. Furthermore, the inspectors discussed CEDMCS operability in light of Generic Letter 91-18 guidance with site management.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the interim disposition and operability determinations associated with the following CRs to ensure that TS operability was properly supported and the SSC remained available to perform its safety function with no unrecognized increase in risk. The inspectors reviewed the UFSAR, applicable supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim CR disposition.

- CR 02-3002, 1B2 EDG AC Lube Oil Soakback pump motor failure
- CR 02-2850, 2879, etc., Unit 2 Intake Cooling Water (ICW) pipe corrosion
- CR 02-1696, Unit 1 Low Pressure Safety Injection (LPSI) system inconsistent hot leg flow
- CR 02-1756 and 2192, 2A ICW pump performance degradation

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope

2B2 Safety Injection Loop Check Valve Leakage

The inspectors reviewed the Operator Work Around (OWA) log for this specific item, and discussed it in detail with Operations supervision. The inspectors also reviewed recent non-licensed operator logs to verify the pressure downstream of V3661 was being recorded on a regular basis (using the temporary gage) and was not indicative of reactor coolant system (RCS) leakage in excess of TS requirements.

Cumulative Effects

The inspectors performed a semi-annual evaluation of the potential cumulative effects of all outstanding OWAs. At the time of the inspection, there were only seven total OWAs for both units; only one of these involved safety-related equipment. The inspectors evaluated all outstanding OWAs for their cumulative effects, and discussed these potential effects with control room supervision and operators. The inspectors also reviewed the minutes for the third quarter OWA Team meeting that systematically examined individual and cumulative OWA status and repair priority, and assessed overall risk. Furthermore, the inspectors reviewed the current OOS logs and walked down the control rooms to verify OWAs were being identified and properly entered into the corrective action program.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the modification package and work order (WO) 32014849 for Plant Change and Modification (PC/M) 02077 to replace the existing temporary CEDMCS air conditioning units with a permanent air conditioning ventilation system (HVA-5A/5B). As part of PC/M 02077, the inspectors reviewed the 10 CFR 50.59 screening, safety classification determination, seismic evaluation and Appendix R review performed by the licensee, and verified that TS changes and NRC approval were not required for the modification. The inspectors also observed portions of the interim and permanent system installation per the approved work order, including the breeching of fire barriers and Class 1 seismic walls and structures. Furthermore, the inspectors conducted walk downs and monitored operation of the interim air handling unit, and the change-over to the permanent two train system, to verify proper installation and assure the impact on TS required and safety-related equipment was adequately addressed.

The Updated Final Safety Analysis Report (UFSAR) Change package for PC/M 02077 was also reviewed by the inspector.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed applicable post maintenance test (PMT) procedures and witnessed testing activities following maintenance of the risk significant SSCs listed below. The following aspects were specifically inspected: (1) Effect of testing on the plant recognized and addressed by control room and/or engineering personnel; (2) Testing consistent with maintenance performed; (3) Acceptance criteria demonstrated operational readiness consistent with design and licensing basis documents such as TS, UFSAR, and others; (4) Range, accuracy and calibration of test equipment; (5) Step by step compliance with test procedures, and applicable prerequisites satisfied; (6) Control of installed jumpers or lifted leads; (7) Removal of test equipment; and, (8) Restoration of SSCs to operable status. The inspectors also reviewed problems associated with the PMTs to ensure that they were correctly identified and appropriately entered into the corrective action program.

- 1B EDG following routine maintenance
- 1A Auxiliary Feedwater pump and motor after a complete overhaul
- 1B High Pressure Safety Injection pump breaker following PC/M 02-062

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors evaluated planned outage activities for the eighteenth Unit 1 refueling outage (SL1-18) which began on September 30. The inspectors reviewed the risk reduction methodologies developed and employed by the licensee to control system configurations during SL1-18. To assess the effectiveness of the licensee's configuration control management, the inspectors used applicable TS; the UFSAR; and guidance described in NRC generic correspondence.

Outage Plans

The inspectors reviewed the licensee's efforts for considering risk, industry experience, and lessons learned. The inspectors reviewed the licensee's safety system protection plans for SL1-18 in accordance with Administrative Procedure O-AP-010526, Outage

Risk Assessment and Control, and examined their implementation, to verify whether a defense in depth concept was in place to ensure safe operations and avoid unnecessary risk.

Monitoring of Shutdown Activities

The inspectors witnessed the shutdowns of Unit 1 on September 29 and 30, and verified the cooldown rate was within TS. The inspectors also monitored plant parameters and verified whether shutdown activities were conducted in accordance with applicable emergency operating procedures, and plant General Operating Procedures, such as 1-GOP-123, Turbine Generator Shutdown - Mode 1 To Mode 3, and 1-GOP-305, Reactor Plant Cooldown - Hot Standby To Cold Shutdown.

Outage Activities

The inspectors examined critical outage activities to verify whether they were conducted in accordance with TS, licensee procedures, and the licensee's outage risk control plan. Some of the more significant inspection activities accomplished by the inspectors were as follows:

- Reviewed selected safety-related equipment clearance orders
- Verified operability of reactor coolant system (RCS) pressure, level, flow, and temperature instruments
- Verified electrical systems availability and alignment
- Monitored important control room plant parameters
- Verified shutdown cooling system and spent fuel pool cooling system operation
- Evaluated implementation of reactivity controls
- Reviewed control of containment penetrations
- Examined foreign material exclusion (FME) controls put in place inside containment (e.g., around the refueling cavity, near sensitive equipment and RCS breaches) and around the spent fuel pool
- Verified compliance with TS overtime limits

Refueling Activities

The inspectors observed fuel handling operations being performed according to TS and applicable operating procedures. The inspectors also examined licensee activities to control and track the position of all fuel assemblies. The inspectors also evaluated the licensee's ability to close the containment equipment, personnel, and emergency hatches in a timely manner per their procedural controls.

Heatup and Startup Activities

The inspectors examined selected TS, license conditions, and other commitments and administrative prerequisites were being met prior to mode changes. The inspectors also specifically reviewed the initial RCS inventory balance used to measure RCS leakage, and verified containment integrity was properly established. The inspectors performed a containment sump closeout inspection during Mode 4, and a containment walkdown when the plant had reached Mode 3 and was at normal operating pressure and temperature. Lastly, the inspectors observed portions of the reactor startup and power ascension, and discussed the results of low power physics testing with Reactor Engineering and Operations to ensure that the core operating limit parameters were consistent with the design.

Correction Action Program

The inspectors reviewed almost all of the CRs generated during SL1-18 to evaluate the licensee's threshold for initiating CRs. The inspectors also selected numerous CRs to verify appropriate priorities, mode holds, and significance levels were being assigned. Resolution and implementation of corrective actions of several CRs were also examined. Furthermore, the inspectors routinely reviewed the results of Quality Assurance daily surveillances of outage activities.

b. Findings

Introduction: A Green noncited violation (NCV) was identified by the inspectors for multiple instances of plant personnel exceeding the overtime limits of TS 6.2.2.f during SL1-18 without proper authorization and documentation.

Description: On October 14, the inspectors remotely observed licensee activities in containment during the early part of day shift as they reinstalled the Unit 1 upper guide structure (UGS). The inspectors observed that the night shift reactor head crew and HP technicians had been held over to perform this evolution. Both the reactor head crew and HP technicians were working seven twelve hour shifts during SL1-18 as permitted by the Plant General Manager's (PGM) pre-authorization memo issued before the outage in accordance with Section 6.2.1.A of ADM-09.07, Overtime Limitations For Plant Personnel. However, during the UGS reinstallation, the reactor head crew and HP technicians exceeded the overtime limit of 24 hours in a 48-hour period prescribed by Section 6.1.2.A.2 without proper authorization or documentation. On the morning of October 14, just prior to shift change, the Outage Control Center (OCC) Shift Director made the decision to hold over the night shift reactor head crew and HP without obtaining proper authorization from the PGM as required by ADM-09.07, nor did he complete the required Appendix A, Request To Deviate From Overtime Guidelines, of ADM-09.07 to document the overtime extensions.

In response to the inspectors concerns regarding overtime violations during the UGS lift and other probable instances during SL1-18, the licensee initiated CR 02-2857. After further investigation of the reactor head crew gate logs, the licensee identified 21 additional instances of overtime violations without proper authorization and/or documentation required by ADM 09.07. Based on this investigation, and interviews with plant OCC management and maintenance supervision, the licensee concluded "that station personnel were unaware of the procedural requirement to process and obtain correct authorization prior to exceeding overtime limits."

Analysis: The finding described above was caused by inadequate management and supervisory awareness of the administrative requirements of ADM-09.07. This finding was greater than minor because if left uncorrected it could become a more significant safety concern due to excessive fatigue by personnel performing safety-related activities. There is no particular cornerstone associated with this finding. The safety significance of the finding was very low (Green) because there were no specific performance deficiencies associated with the individuals during the time they exceeded the established overtime limits. This non-SDP finding was reviewed by NRC management.

Enforcement: Technical Specification 6.2.2.f requires administrative procedures be developed and implemented to limit the working hours of personnel who perform safety-related functions. The TS also require that any deviations from overtime limitations shall be authorized by the PGM in accordance with approved administrative procedures, with documentation of the basis for granting the deviation. Administrative procedure ADM 09.07 establishes these TS required guidelines. Contrary to the above, multiple instances were identified where plant personnel performed safety-related work in excess of the overtime limits established by ADM 09.07 without obtaining proper authorization and/or documenting the overtime deviation. However, because this failure to adequately implement the TS required administrative procedure for controlling overtime is considered to be of very low safety significance and has been entered into the licensee's corrective action program as CR 02-2857, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-335/02-04-01, Failure To Maintain Control Of Overtime Limits During SL1-18.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed and witnessed the conduct of the surveillance tests listed below in accordance with applicable operating procedures (OP), and operations surveillance procedures (OSP). Applicable test data was reviewed to verify whether it met TS, UFSAR, and/or licensee procedure requirements. The inspectors also verified that the testing effectively demonstrated the systems were operationally ready, capable of performing their intended safety functions, and that identified problems were entered into the corrective action program for resolution.

- OP 1-2200050A, 1A EDG Periodic Test, including inservice test of the 1A diesel generator fuel oil transfer pump
- OP 1-0410050, 1B LPSI Substantial Flow Test
- 1-OSP-09.14, Main Feedwater Isolation Valve Periodic Test
- OP 1-0400050, Section 8.10, 1A EDG Loaded 24 Hour Run

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors continued to periodically screen active temporary modifications, especially for risk significant systems. The inspectors specifically examined TSA #2-02-005 regarding installation of a temporary test gage and compensatory guidance to monitor 2B2 safety injection loop check valve RCS seat leakage. The technical evaluation and associated 10CFR50.59 screening of this TSA were reviewed against the system design basis documentation to ensure that (1) the modification did not adversely affect operability or availability of other systems, (2) the installation was consistent with applicable modification documents, and (3) did not affect TS or warrant prior NRC approval. The inspector also walked down the installation of the TSA to verify configuration control was maintained. Furthermore, the inspectors verified and reviewed required condition monitoring by Operations, and discussed compensatory actions detailed by the TSA with Operations supervision.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness (EP)

EP6 Drill Evaluation

a. Inspection Scope

On December 5, the inspectors monitored the participation of an operating crew in the simulator during the fourth quarter EP drill of the site emergency response organization. During this drill the inspectors assessed operator actions in the control room simulator to verify whether emergency classification, notification, and protective action recommendations were made in accordance with implementing procedures. Additionally, the inspectors evaluated the adequacy of the post drill critiques conducted in the simulator.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Reactor Safety - Initiating Events

a. Inspection Scope

Using the criteria specified in NEI 99-02, Revision 2, Regulatory Assessment Performance Indicator Guideline, an inspector reviewed the data associated with the following performance indicators reported to the NRC:

1) Unplanned Power Changes,
2) Unplanned (Automatic and Manual) Scrams, and
3) Scrams With Loss of Normal Heat Removal

The inspectors reviewed the performance indicator data reported by the licensee for Units 1 and 2 during the first three quarters of 2002. The inspectors also reviewed the input data for the fourth quarter of 2002 to be reported in January 2003. To verify the performance indicator data was complete and accurate, the inspectors reviewed applicable reactor operator logs, CRs, Licensee Event Reports (LERs), and data sheets for ADM-25.02, NRC Performance Indicators.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Annual Sample Review

a. Inspection Scope

The inspectors selected three condition reports (CRs), listed below, for detailed review and discussion with the licensee. These CRs were examined to verify whether problem identification was timely, complete and accurate; safety concerns were properly classified and prioritized for resolution; technical issues were evaluated and dispositioned to address operability and reportability; root cause or apparent cause determinations were sufficiently thorough; extent of condition, generic implications, common causes, and previous history were adequately considered; and appropriate corrective actions (short and longterm) were implemented or planned in a manner consistent with safety and TS compliance. The inspectors evaluated the CRs against the requirements of the licensee's corrective action program as delineated in Administrative Procedures ADM-07.02, Condition Reports, ADM-08.04, Root Cause Evaluations, and 10 CFR 50, Appendix B.

- CR 02-2661, 1B EDG output breaker failure to close
- CR 02-0704, 1B HPSI pump failure to start on demand
- CRs 02-2879 and 02-2978, Unit 2 ICW pipe corrosion

b. Findings and Observations

There were no significant licensee performance issues identified by the inspectors regarding these three CRs. The inspectors verified that the root/apparent cause evaluation and initial corrective actions were appropriate and timely in relation to the safety significance of the problem. The inspectors did not identify any violation of regulatory requirements. However, the licensee did not fully address all the provisions of Generic Letter (GL) 90-05, Guidance For Performing Temporary Non-Code Repair Of ASME Code Class 1, 2, And 3 Piping, in their disposition of CR 02-2978. In particular, the licensee did not adequately document their evaluation of the predicted flaw propagation/degradation required by the GL 90-05 "Wall Thinning" approach, nor their basis for foregoing additional nondestructive examination of the through wall flaw temporary non-code repairs . This evaluation and basis was subsequently provided in an additional attachment to CR 02-2978.

.2 Control of Overtime Limits During SL1-18

The licensee failed to identify multiple, repetitive instances of noncompliances with the overtime limits prescribed by TS 6.2.2.f and ADM-09.07 during the unit 1 outage (Section 1R20). Quality assurance surveillance activities specifically targeted to verify conformance with established overtime limitations were ineffective in identifying the lack of overtime control and awareness by outage management, supervision, and personnel.

.3 Minimum Shift Staffing in the Main Control Room

On October 23, during the course of a backshift control room tour as part of the routine Plant Status review of the baseline inspection program, the inspectors discovered less than the normal complement of reactor operators in the Unit 2 main control room. During power operation the normal control room staffing is two reactor operators (RO) and one senior reactor operator (SRO), consistent with the minimum shift staffing of TS 6.2.2. At the time of the inspector's tour, there was only one RO in the Unit 2 control room, the other RO had gone over to Unit 1. Although TS 6.2.2 only requires one of the ROs to remain in the control room at all times, this was not the normal shift staffing. Further investigation by the inspectors revealed that the second RO would frequently leave the control room for short periods, with no specific controls over the duration or destination of his absence and with no direct means of contact while away.

After discussions with Operations management and onshift supervisors, and reviewing relevant sections of AP-0010120, Conduct of Operations, the inspectors concluded that there was a definite lack of clear expectations and guidance regarding the availability of the second RO in the control room during power operations. Furthermore, after interviewing the LOR supervisor, the inspector concluded that the LOR training program was unaware that the minimum shift staffing in the control room was ever less than one SRO and two ROs. Consequently, LOR training had not addressed the actual minimum control room staffing in their program, particularly simulator training and evaluation. To address the inspectors' concern the licensee temporarily terminated this practice, and initiated CR 02-2817 in order to address the issues regarding LOR training and conduct of operations.

4OA3 Event Follow-up

.1 (Closed) LER 50-389/2002-002, Found Cycle 12 Pressurizer Safety Valve Setpoints Outside Technical Specification Limits.

This LER reported that two of the three code pressurizer safety valves exceeded their TS setpoints after removal from the plant during the Unit 2 Cycle 13 refueling outage. Technical Specification 3.4.2.2 required that the pressurizer safety valves lift at 2500 psia plus or minus two percent. As determined through testing by an offsite vendor, two of the valves lifted at greater than two percent above the setpoint and the third one lifted at greater than three percent above the nameplate setpressure. The ANSI/ASME OM-1987, Part 1, code required the licensee to perform a cause determination and to implement corrective action when a tested pressurizer safety relief valve exceeded the nameplate setpressure by greater than three percent. No safety analysis limits were violated for any of the UFSAR analyzed events. The apparent cause of failed pressurizer safety valve tests was due to valve spring performance problems and mechanical setpoint drift over the operating cycle. The licensee replaced spring assemblies for the affected valves. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented the failed equipment in CR 02-1786. This LER is closed.

.2 (Closed) LER 50-389/2002-001, Control Room Envelope Degraded During Door Seal Maintenance Activities.

a. Inspection Scope

The inspectors reviewed the LER and CR 02-1010, which documented this event in the corrective action program, to verify that the cause of the control room envelope degraded event was identified and that corrective actions were reasonable.

b. Findings

Introduction: A Green self-revealing NCV of TS 3.7.7 Action b was identified for inadequate door seal during maintenance activities which resulted in both trains of Unit 2 control room emergency air cleanup system (CREACS) being inoperable for a time longer than 24 hours.

Description: On May 13, 2002, while Unit 2 was at 100 percent power, the licensee started repair activities on control room door RA-114, an external door of a two-door vestibule. RA-114 was fully opened to determine if the inner door of the two door vestibule, RA-108, was capable of maintaining the control room pressure boundary for an extended period of time. The licensee erroneously concluded that door RA-114 did not affect the control room pressure boundary and therefore, no TS LCO was entered. On May 16, 2002, TS 3.7.7 Action b was voluntarily entered for an inoperable CREACS during the restoration of an unrelated ventilation system TSA. A TS surveillance test was performed to ensure that the restoration had no adverse effect on the control room envelope. The CREACS is required to maintain the control room envelope at an average positive pressure of 1/8 inch water gage (WG) above that of surroundings during normal plant operation and following a loss-of-coolant accident (LOCA). Subsequently, both trains of CREACS failed to pass the acceptance criteria. The licensee determined that this event was caused by personnel errors because the degraded seal conditions of the doors RA-108 and RA-114 were not adequately evaluated during maintenance activities. Door RA-108 was previously identified as having no door seals but no corrective maintenance had been performed. This condition was not considered an issue because during normal operations the control room pressure remained greater than 1/8 inch WG while the outer vestibule door (RA-114) was opened. However, the licensee failed to recognize that this pre-maintenance check was inappropriate with CREACs in its normal operating lineup because the outside air make up flow was much greater (1,000 cfm) than the flow allowed during accident conditions (450 cfm). Subsequently, seals were installed on door RA-108. Both trains of CREACS satisfactorily passed the TS surveillance on May 16, 2002, and the control room envelope was restored.

Analysis: The inspectors determined that this finding is greater than minor because it affected the barrier integrity cornerstone objective of providing reasonable assurance that physical design barriers provide protection from radionuclide releases caused by accidents or events. The safety significance of the finding was very low (green) because CREACS was able to maintain sufficient positive control room pressure during the time period between May 13 and 16, 2002, and the control room envelope remained operable with respect to its design basis function of maintaining operator dose within general design criterion (GDC) 19. The significance of this issue was characterized as “Green” by the Phase 1 screening worksheet for “Containment Barriers” of the significance determination process detailed in Inspection Manual Chapter 609, Appendix A, Attachment 1.

Enforcement: Technical Specification 3.7.7 requires that with both control emergency air cleanup systems inoperable, restore at least one system to OPERABLE status within 24 hours or be in at least HOT STANBY within the next 6 hours and COLD SHUTDOWN within the next 30 hours. Contrary to the above, on May 13, 2002, the licensee failed to adequately evaluate degraded door seal conditions during maintenance activities which resulted in both trains of Unit 2 CREACS inoperable for time period longer than 24 hours. Because the failure to adequately evaluate degraded door seal conditions is of very low safety significance and has been entered into the licensee’s corrective action program (CR 02-1010), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-389/02-04-02, Inadequate Door Seal Resulted in Both Unit 2 Control Room Emergency Air Cleanup System Trains Inoperable for a Time Longer than 24 Hours.

.3 Unit 1 Unplanned Manual Reactor Trip

a. Inspection Scope

On October 24, 2002, during the startup of Unit 1 following SL1-18, the reactor was manually tripped from approximately 7% power due to a loss of all main feedwater. An inspector responded to the control room and confirmed that the unit was stable in Mode 3, and that all safety-related mitigating systems had operated properly. Operator and plant response was verified to be as expected by reviewing plant parameters, strip charts, and the Sequence of Events Recorder; and discussing the event with plant operators and members the licensee’s Event Review Team. The only equipment problems of any significance involved nonsafety-related secondary systems (e.g., MFW pump discharge isolation valves) which did not adversely affect the operators ability to safely shutdown the unit. The inspectors also discussed the risk significance with Region II personnel and verified that appropriate notifications were made in accordance with 10 CFR 50.72. Furthermore, the inspector reviewed the draft post-trip report and attended the Facility Review Group meeting for restart.

b. Findings

No finding of significance were identified

4OA5 Other

.1 Reactor Vessel (RV) Head Penetration Inspection

a. Inspection Scope (TI 2515/145)

The inspectors observed activities relative to inspection of the Unit 1 reactor vessel head penetrations to verify commitments made in the licensee's response to NRC Bulletins 2001-01 and 2002-02. The guidelines for the inspection were provided in NRC temporary instruction (TI) procedure TI2515/145, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (NRC Bulletin 2001-01).

The inspection included review of nondestructive examination (NDE) procedures, assessment of NDE personnel training and qualification, and observation and assessment of Ultrasonic (UT) and Remote Visual (VT) examinations. Discussions were also held with contractor representatives and licensee personnel. These activities were examined to verify licensee compliance with regulatory requirements, and gather information to help the NRC staff identify possible further regulatory positions and generic communications.

Specifically, the inspectors reviewed and observed:

- Automated UT scanning analysis activities of the inside diameter (ID) of the nozzles.
- Remote VT examination of the external surface of the head and the junction of the penetration and head.

b. Findings

There were no indications of RV head or penetration degradation identified by the licensee during the observed inspections. No findings of significance were identified.

.2 TI 2515/145-05 Reporting Requirements:

a. Was the examination:

1. Performed by qualified and knowledgeable personnel?

The "bare-metal" visual examinations of the RV head were conducted by contractor personnel working for Framatome. Personnel involved were certified visual inspectors by Framatome.

The Ultrasonic examinations of the penetration nozzles were conducted by Framatome, using Framatome qualified and certified data collectors and evaluators.

For both the UT & VT examinations, the qualification documentation for the Level II & Level III UT & VT-2 personnel performing the inspection was verified. The inspectors reviewed the inspection standards, acceptance criteria as described in the inspection procedures, the calibration requirements of the camera and lighting, and the resolution and sensitivity requirements for the inspection equipment, and found that the inspection personnel were very knowledgeable with the requirements in all of these areas.

2. Performed in accordance with approved and adequate procedures?

The inspectors reviewed applicable inspection procedures and verified they had been reviewed and approved through the licensee's vendor procedure review process.

The inspectors witnessed that bare metal RV head visual examinations were performed in accordance with the following licensee approved work instructions and contractor procedures:

WO 31011907	Reactor Head CEDM Visual Inspection
FRA-ANP 6015743A	Reactor Head Nozzle Penetration Remote Visual Inspection Plan for St. Lucie Unit 1
FRA-ANP-54-ISI-367-03	Procedure for the Visual Examination for Leakage of Reactor Head Penetrations

Ultrasonic examinations of the RV head penetrations were conducted in accordance with licensee approved contractor procedure No. 54-ISI-100-09, "Remote Ultrasonic Examination of Reactor Head Penetrations," Rev. 9, dated Sept, 9, 2002. The procedure was for ACCUSONEX™ data acquisition system and referenced Procedure Qualifications No. PQ-100-1, 54-PQ-100-2, 3, 4, and 5.

During the UT and VT examinations, the inspectors verified that the examiners used the procedures and noted that the approved acceptance criteria and/or critical parameters for the reviews were applied in accordance with the procedures.

3. Adequately able to identify, disposition, and resolve deficiencies?

The inspectors reviewed the vendor procedures controlling the VT and UT examination techniques and determined they provided adequate guidance to ensure the licensee would be able to identify, disposition and resolve relevant indications.

For the visual inspections, the inspectors observed implementation of the licensee's inspection plan for keeping track of vessel head penetration (VHP) position, and specific quadrants, using applicable drawings and specific reference points. Inspectors confirmed licensee actions were adequate to ensure that visual examinations included 100% circumferential coverage of each VHP. The inspectors verified that the examination result for each penetration was individually documented. The examination procedure provided evaluation criteria for the VT-2 examination with specific actions for the detection of boric acid residues or identified leakage. No VHP leakage was identified. Although some minor indications of boric acid leakage associated with incore instrument (ICI) nozzle flange disassembly was observed, these were readily recognized and dispositioned. The licensee also dispositioned numerous VHP quadrants that were partially to completely obstructed by minor debris, insulation and/or other material on the head (see item c. below). The licensee reexamined every potentially obstructed quadrant in detail, and documented their disposition of each one, which the inspectors observed and reviewed.

4. Capable of identifying the Primary Water Stress Corrosion Cracking (PWSCC) phenomenon described in the bulletin?

For the UT inspections, the circumferential (axial beam direction) blade probe and nominal axial (circumferential beam direction) blade probe have been demonstrated for flaw detection and characterization. For the VT inspections, the circumferential blade probe is the primary inspection probe as it has been demonstrated for the detection of ID and OD surface connected circumferential, off-axis and axial flaws. The nominal axial blade probe has also been demonstrated as having equivalent capabilities.

The inspectors directly observed the Unit 1RV head assembly on its stand in containment; monitored the licensee's conduct of the examination; directly observed remote video images of a significant percentage of the VHP nozzles; discussed the examination process and progress with the examiners prior to and during the visual examination program; and reviewed the documentation to verify 100% circumferential remote visual access of each VHP. The licensee was able to view each of the 69 CEDM, head vent, and ICI nozzles during the visual examinations. However, due to the extent of disbursed obstructions from minor debris, small objects, and pieces of insulation, and the increased difficulty of very limited clearance between the vessel head and the installed insulation package that precluded effective clearing/cleaning, a complete 100% visual inspection was limited (see item c. below). But based on complementary UT results discussed with NRR, the inspectors concluded that the licensee had conducted an effective examination of the Unit 1 RV head that was capable of identifying any significant leakage resulting from PWSCC cracking of VHP nozzles, with one exception. Penetration #2 (CEDM) lacked sufficient UT and VT coverage to conduct an effective examination. This issue was specifically addressed by CR 02-2439 and discussed at length with NRR. The licensee subsequently submitted their technical basis for supporting continued operation as part of their 30 day bulletin response letter dated November 21, 2002.

b. What was the condition of the reactor vessel head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

The reactor vessel head insulation was not removed to conduct the visual inspection, except for the outer circumferential row of metal insulation panels around the eight in-core instrumentation (ICI) columns to facilitate access of an articulating video probe underneath the insulation. The clearance between the head surface and the installed metal insulation package was very limited, to nonexistent in many areas, requiring the use of pry bars and expandable hoses to lift the insulation up. The vast majority of the outer head surface was free of obstructions and relatively clean, except for a considerable amount of disbursed debris and material in the form of small pieces, parts and fragments (e.g., fibrous insulation, paint chips, metallic filings, dirt, wires, fastners, etc.). There was also some minor, localized, surface evidence of dried boric acid that was satisfactorily dispositioned as primarily ICI flange leakage or spillage. There were no significant boron deposits observed that would have been indicative of PWSCC. No wastage or evidence of boric acid leakage from penetrations was identified.

c. Could small boron deposits, as described in the bulletin, be identified and characterized?

The clarity, lighting, and magnification capabilities of the remote video probe demonstrated itself capable of discerning and characterizing extremely small quantities of boric acid deposition. However, due to the wide disbursal of minor debris on the head, a large percentage of the VHP quadrants had small, localized quantities of obstructing material at the nozzle to head interface. Combined with the inability to adequately clean the head due to clearance problems, many of the quadrants presented a major challenge for the contractor in being able to distinguish very small boron deposits. Although many of the obstructed VHP quadrants were satisfactorily reexamined by remotely viewing the quadrant from different angles, re-reviewing the video tape, and/or mechanically cleaning the nozzle interface, there still remained dozens of quadrants the licensee was unable to remove obstructing material to clearly see 100% of the interface area. Consequently, the licensee was unable to positively determine whether very small boron deposits existed or not in many cases, and had to rely on indirect evidence (e.g., lack of boric acid runoff, displacement of debris from the nozzle interface, etc.).

d. What material deficiencies (associated with the concerns identified in the bulletin) were identified that required repair?

No material deficiencies were identified that required repair.

e. What, if any, significant items that could impede effective examinations and/or ALARA issues were encountered?

ALARA issues were a serious consideration during the inspection. The reactor head inspection work areas were posted as High Rad and Very High Rad and required continuous monitoring by HP technicians both on location and remotely. Extremely limited clearances between the head and metal insulation package presented a very difficult challenge for conducting an effective visual examination (see above). Physical interferences on the inside nozzle surfaces precluded full UT coverage in many cases.

.3 <u>Temporary Instruction (TI) 2515/148, Appendix A, Pre-inspection Audit for Interim Compensatory Measures (ICMs) at Nuclear Power Plants</u>

The inspectors conducted an audit of the licensee’s actions in response to a February 25, 2002 Order, which required the licensee to implement certain interim security compensatory measures. The audit consisted of a broad-scope review of the licensee’s actions in response to the Order in the areas of operations, security, emergency preparedness, and information technology as well as additional elements prescribed by the TI. The inspectors selectively reviewed relevant documentation and procedures; directly observed equipment, personnel, and activities in progress; and discussed licensee actions with personnel responsible for development and implementation of the interim compensatory measures actions.

The licensee's activities were reviewed against the requirements of the February 25, 2002 Order; the provisions of TI 2515/148, Appendix A; the licensee's response to the Order; and the provisions of the NRC-endorsed NEI Implementation Guidance, dated July 24, 2002.

No findings of significance were identified. A more in-depth review of the licensee's implementation of the February 25, 2002 Order, utilizing Appendix B and C of TI 2515/148 will be conducted in the near future.

4OA6 Meetings

.1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. Don Jernigan and other members of licensee management on January 3, 2002. Interim exits by regional inspectors were conducted on October 10. The licensee acknowledged the findings presented. No proprietary information was identified.

Supplemental Information

A. PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Bird, Protection Services Manager
R. Coleman, Instrumentation and Controls Department Supervisor
R. De La Espriella, Site Quality Manager
B. Dunn, Site Engineering Manager
R. Hughes, Systems & Component Engineering Manager
D. Jernigan, Site Vice President
J. Kirkpatrick, Maintenance Manager
K. Korth, Licensing Manager
R. McCullers, Health Physics Supervisor
R. McDaniel, Fire Protection Supervisor
D. Mohre, Maintenance Rule Administrator
T. Patterson, Operations Manager
J. Porter, Operations Support Engineering Manager
A. Pell, Training Manager
R. Rose, Plant General Manager
A. Scales, Operations Supervisor
G. Varnes, Security Supervisor
J. Voorhees, Corrective Action Group Supervisor
S. Wisla, Acting Health Physics Supervisor

Other licensee employees contacted include office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

NRC

E. Brown, NRR Project Manager

B. ITEMS OPENED AND CLOSED

Closed

50-335/02-04-01	NCV	Failure To Maintain Control Of Overtime Limits During SL1-18 (Section 1R20)
50-389/02-04-02	NCV	Inadequate Door Seal Resulted in Both Unit 2 Control Room Emergency Air Cleanup System Trains Inoperable for a Time Longer than 24 Hours (Section 4OA3.2).
50-389/2002-002	LER	Found Cycle 12 Pressurizer Safety Valve Setpoints Outside Technical Specification Limits (Section 4OA3.1)
LER 50-389/2002-001	LER	Control Room Envelope Degraded During Door Seal Maintenance Activities. (Section 4OA3.2)

2515/145	TI	Circumferential Cracking of Reactor Vessel Head Penetration Nozzles (NRC Bulletin 2001-01) for Unit 1 (Section 4OA5.1)

<u>List of Documents Reviewed</u> (4OA5 & 1R08)

<u>Procedures</u>

- Framatome Procedure 54-ISI-100, “Remote Ultrasonic Examination of Reactor Head Penetrations,” Rev. 9, dated September 9, 2002.
- 54-ISI-367-03, “Procedure for the Visual Examination for Leakage of Reactor Head Penetrations”, Rev. 3, dated November 15, 2001.
- NDE 5.2, Rev. 11, Ultrasonic Examination of Ferritic Piping Welds
- NDE 5.18, Rev. 6, Ultrasonic Thickness Measurements
- NDE 9.3, Rev. 0, Radiographic Examination General Requirements
- JPE-M-87-102, Rev 16, Snubber Testing Acceptance Criteria

<u>Other Documents</u>

- Letter FPL to USNRC, September 11, 2002, Reactor Pressure Vessel Head Penetration Nozzle Inspection Programs.
- Reactor Head Nozzle Penetration Remote Visual Inspection Plan for St. Lucie Unit 1, Rev 2.
- WCAP-15945, Structural Integrity Evaluation of Reactor Vessel Upper Head Penetrations to Support Continued Operation: St. Lucie Unit 1, Rev. 0, September 2002
- WCAP-15946, Technical Basis for Repair Options for Reactor Vessel Upper Head Penetrations Nozzles and Attachment Welds: St. Lucie Unit 1, Rev. 0, October 2002
- CR 02-2979, Davis Besse: Review of PSL Boric Acid Leakage Detection Program