PREDECISIONAL
DRAFT INFORMATION - NOT FOR DISTRIBUTION

Florida Power & Light Company
ATTN: T. F. Plunkett
President - Nuclear Division
P. O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: NRC INTEGRATED INSPECTION REPORT NOS. 50-335/96-04 AND 50-389/96-04 AND NOTICE OF VIOLATION

Gentlemen:

This refers to the inspection conducted on February 18 through March 30, 1996, at the St. Lucie facility. The purpose of the inspection was to determine whether activities authorized by the license were conducted safely and in accordance with NRC requirements. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

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

Based on the results of this inspection, the NRC has determined that violations of NRC requirements occurred. The violations are cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding them are described in detail in the subject inspection report. The violations are of concern because they indicate that personnel performance with respect to procedure compliance and usage and attention to detail persist even after corrective actions had been completed for previous, similar, violations. Particularly illustrative of this point is a violation for failures associated with the Unit 1 containment particulate/iodine/gaseous radiation monitor. The event displayed particularly poor performance on the part of several individuals and included aspects of failing to access and follow a procedure, compounded by failing to capitalize on multiple opportunities to identify the inoperable component through logtaking. Logtaking weaknesses were further compounded by the fact that non-licensed operators taking the logs were electronically prompted that a key parameter associated with the component's operability was unacceptably low. The failure to pursue this condition, over six logtaking opportunities, would tend to indicate that a lack of a questioning attitude extends to multiple personnel. It is also noted that a failure to employ an approved procedure lead to a condition of Emergency Diesel Generator inoperability (the subject of another violation in the enclosed report).

AAAA11

PREDECISIONAL
DRAFT INFORMATION - NOT FOR DISTRIBUTION

As documented in the report, we have performed an initial review of the Licensee Event Report you submitted for the subject event. While we found your immediate corrective actions appropriate, we question the scope of the actions delineated in your transmittal. Consequently, in your response to the enclosed Notice, please describe what actions you will take to instill, in non-licensed operators, an understanding of the vital role they play in the early detection of off-normal conditions during logtaking and log review. Additionally, please describe your basis for believing that other cases of inoperability in components have not been overlooked through similar errors and any actions you have taken (or plan to take) to identify those components which may be rendered inoperable in a similar manner (by non Operations personnel performing routine evolutions for which the control room may not have cognizance). We would be very interested in how your Plan to Improve Operational Performance initiative is (or will be) addressing the problems leading to this violation. Please be prepared to discuss this issue at the next FPL/NRC management meeting.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC Public Document Room (PDR). To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without reduction.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

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

Sincerely,

Kerry D. Landis, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosures: Notice of Violation
Inspection Report

cc w/encl: (See page 2)
NOTE: ADD CC & BCC LISTS FROM 5520

PREDECISIONAL
DRAFT INFORMATION - NOT FOR DISTRIBUTION

NOTICE OF VIOLATION

Florida Power & Light Company
St. Lucie 1

Docket Nos. 50-335
License Nos. DPR-67

During an NRC inspection conducted on February 18 through March 30, 1996, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," (60 FR 34381; June 30, 1995), the violations are listed below:

A. Technical Specification 6.8.1.a requires that written procedures be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Rev 2, February, 1978. Appendix A, paragraph 1.d includes administrative procedures for procedural adherence. QI 5-PR/PSL-1, Rev 68, "Preparation, Revision, Review/Approval of Procedures," Section 5.13.1, states that all procedures shall be strictly adhered to.

Step 7.5.1.R of procedure HPP-22, Rev 2, "Air Sampling," required that valve 3 of the Unit 1 containment Particulate Iodine Gaseous Monitor be returned to the open position following the performance of a containment grab sample.

AP 0010120, Rev 79, "Conduct of Operations, Appendix F, "Log Keeping," required, in part, that "Log readings shall be compared to previous readings to detect abnormal trends or conditions and verified to be within the minimum and maximum values for that parameter. All log readings outside the min/max values shall be circled with reasons stated for abnormal readings (i.e., OOS, NPWO, ISOL, etc)."

Contrary to the above:

1. On February 22, 1996, a health physics technician performing a grab sample of the Unit 1 containment failed to return valve 3 to the open position and, as a result, rendered the monitor inoperable.

2. On February 22, 23, and 24, 1996, Senior Nuclear Plant Operators failed to perform adequate reviews of logs taken in the Unit 1 Reactor Auxiliary Building, as the out-of-specification log readings taken on the Unit 1 containment particulate iodine gaseous monitor were not highlighted and explained. As a result, the Unit 1 containment Particulate Iodine Gaseous monitor remained inoperable and Unit 1 transitioned from Mode 3 to Mode 2 without satisfying Technical Specification Limiting Condition for Operation 3.4.6.1. The Mode transition was prohibited by Technical Specification 3.0.4.

This is a Severity Level IV violation (Supplement I).

B. Technical Specification 6.8.1.a requires that written procedures be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Rev 2, February, 1978. Appendix A, paragraph 1.d includes administrative procedures for procedural adherence. QI 5-PR/PSL-1, Rev 68, "Preparation, Revision, Review/Approval of Procedures," Section 5.13.1, states that all procedures shall be strictly adhered to.

AP 0010120, Rev 80, "Conduct of Operations," Appendix F, "Log Keeping," required, in part, that reactivity manipulations be entered in the Reactor Controls Operator Chronological Log.

AP 0010120, Rev 80, "Conduct of Operations," Appendix F, "Log Keeping," required, in part, that abnormal conditions in turbine-generator auxiliary systems be entered in the Reactor Controls Operator Chronological Log.

Contrary to the above:

1. On March 27, 1996, an NRC inspector observed St. Lucie Unit 1 operators perform two Reactor Coolant System dilutions (reactivity manipulations) which, upon later review, were found to have not been entered in the Reactor Controls Operator Chronological Log.

2. On March 27, 1996, hydrogen was added to restore a low pressure condition in the St. Lucie Unit 1 generator. Upon later review, it was determined that the evolution was not entered in the Reactor Controls Operator Chronological Log.

This is a Severity Level IV violation (Supplement I)

C. Technical Specification 6.8.1.a requires that written procedures be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Rev 2, February, 1978. Appendix A, paragraph 1.d includes administrative procedures for procedural adherence. QI 5-PR/PSL-1, Rev 68, "Preparation, Revision, Review/Approval of Procedures," Section 5.13.1, states that all procedures shall be strictly adhered to.

OP 1-2200050A, Rev 24, "1A Emergency Diesel Generator Periodic Test and General Operating Instructions," Appendix E required, in part, that the 1A Emergency Diesel Generator Fuel Oil Storage Tank be recirculated by establishing a flow path from the tank, through the transfer pump, and through valves V17207 and V17208 back to the tank.

QI 1-PR/PSL-2 , Rev 26, "Operations Organization," and AP 0010120, Rev 79.

"Conduct of Operations," Appendix A, required that Senior Nuclear Plant Operators "...report promptly to the Control Room any equipment or valve manipulations so that the RCO will be aware of the current plant status."

Contrary to the above:

1. On January 5, a Senior Nuclear Plant Operator placed the 1A Emergency Diesel Generator Fuel Oil Storage Tank in recirculation by isolating the discharge of the transfer pump and allowing the fuel to be recirculated back to the tank via the pump's minimum flow line. The isolation of the transfer pump's discharge resulted in the Emergency Diesel Generator being inoperable.

2. On January 5, a Senior Plant Nuclear Operator failed to notify the Unit 1 control room of a valve manipulation made to place the 1A Emergency Diesel Generator on recirculation.

This is a Severity Level IV violation (Supplement I)

D. 10 CFR 50, Appendix B, Criterion XI, "Test Control," requires in part that a test program be established to assure that all testing required to demonstrate that components will perform satisfactorily in service and that test results be evaluated to assure that test requirements have been satisfied. FPL Topical Quality Assurance Report 11.0, Rev 4, "Test Control," step 11.2.3, "Evaluation of Test Results," requires that "...documented test results shall be evaluated against the predetermined acceptance criteria by a group or individual having appropriate qualifications."

Contrary to the above, on May 22, 1993, the licensee failed to adequately evaluate Unit 1 CEDM coil resistance test results to assure that test requirements were satisfied as specified in PWO 63/0046 for PC/M 133-191. This resulted in not identifying and dispositioning 11 CEDMs coils whose resistance readings did not meet the specified item #11, Acceptance Criteria of Attachment 4, "PC/M Testing Document."

This is a Severity Level IV violation (Supplement I)

Pursuant to the provisions of 10 CFR 2.201, the Florida Power & Light Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555, with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violations, or, if contested, the basis for disputing the violations, (2) the corrective steps that have been

taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Because your response will be placed in the NRC Public Document Room (PDR), to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without reduction. However, if you find it necessary to include such information, you should clearly indicate the specific information that you desire not to be placed in the PDR, and provide the legal basis to support your request for withholding the information from the public.

Dated at Atlanta, Georgia
this _____day of _____ 19_____.

PREDECISIONAL
DRAFT INFORMATION - NOT FOR DISTRIBUTION

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-335, 50-389
License Nos:	DPR-67, NPF-16
Report No:	50-335/96-04, 50-389/96-04
Licensee:	Florida Power & Light Co.
Facility:	St. Lucie Nuclear Plant, Units 1 & 2
Location:	9250 West Flagler Street Miami, FL 33102
Dates:	February 18 - March 30, 1996
Inspectors:	M. Miller, Senior Resident Inspector S. Sandin, Resident Inspector M. Thomas, Reactor Inspector, paragraph M1.2 F. Wright, Reactor Inspector, paragraphs R1, R3, R5, R6, R7, and R8 R. Chou, Reactor Inspector, paragraphs 1.2.1 through 1.2.4 E. Lea, Project Engineer, paragraphs 04.2, 04.4, M8.2, M8.3, and M8.4 J. Coley, Reactor Inspector, paragraphs M1.2.5 through 1.2.10 and M3.2 J. Moorman, License Examiner, paragraphs 04.3 and 05
Approved by:	K. Landis, Chief, Projects Branch 3 Division of Reactor Projects

PREDECISIONAL
DRAFT INFORMATION - NOT FOR DISTRIBUTION

EXECUTIVE SUMMARY

St. Lucie Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-335/96-04, 50-389/96-04

This integrated inspection included aspects of licensee operations, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes input from regional inspectors in the areas of Maintenance and Plant Support.

Operations

- Operators performed well during a Unit 1 dropped CEA event on February 22. Response to the transient, declaration of an Unusual Event, and a manual reactor trip (inserted when feedwater anomalies were identified) were all timely and appropriate.

- The return to power of Unit 1 was complicated by an attempt to synchronize to the grid with the main generator disconnects open. A procedural weakness was the root cause.

- Walkdowns of both units' Containment Spray systems resulted in the identification of a number of procedural, drawing and hardware deficiencies.

- Control room observations resulted in the identification of:

  - a failure to employ a procedure for boric acid addition (an additional example of a previous violation - VIO 96-03-01)
  - failures to make required log entries for reactivity manipulations and a main generator hydrogen addition (VIO 96-04-02)

- A containment gaseous/particulate/iodine monitor was rendered inoperable due to a failure to follow procedures, combined with a lack of proper follow through on the part of non-licensed operators taking logs (VIO 96-04-01).

- An Emergency Diesel Generator was rendered inoperable due to a failure to follow procedures while placing the fuel oil tank on recirculation (VIO 96-04-03).

- The requalification program is supporting management expectations for operations and covering timely and important topics.

Maintenance

- The procedures used for testing and maintenance on a number of observed maintenance activities were adequate to provide the details for the craft to perform maintenance, inspection, and calibration. The crafts were knowledgeable and skillful in doing work. The inspectors were satisfied with the work performed. However, one weakness was observed for a crew not signing and dating the work copy of the Work Order in the field prior to physically starting work.

- A review of maintenance procedure revision control indicated that the licensee's program contained vulnerabilities which could result in the wrong revision to a given procedure being used in the field. The licensee's corrective actions were satisfactory.

- There were weaknesses noted in the licensee's maintenance program relative to the SBCS valves and MFRV.

- Reviews of historical data for CEA maintenance revealed that post-modification testing acceptance criteria for Unit 1 CEA power cables were not applied to post-modification test data (VIO 96-04-04).

- Closeout of an Unresolved Item concerning poor HP work practices exhibited by maintenance personnel resulted in a non-cited violation for failure to adhere to Radiation Work Permit requirements (NCV 96-04-05)

Engineering

- The engineering disposition for a deficiency identified in Unit 1 Boroflex panel length was reviewed and found to be satisfactory.

Plant Support

- Based on interviews with licensee staff, record reviews, and observations made during tours of licensee facilities; the inspector found the RP program to be adequately managed and internal and external exposure control programs were effectively implemented with all radiation exposures within 10 CFR Part 20 limits. One non-cited violation was identified concerning failure to follow procedures for the control of contaminated tools utilized in the licensee's radiological control area (NCV 96-04-06).

- The permanent modifications for cooling Unit 2 Containment Building in 1995 was a positive step in increasing worker efficiency and reducing collective outage dose and number of personnel contamination events. The modification demonstrated managements commitment to worker safety, RP and ALARA.

- Unplanned maintenance activities and rework significantly increased outage work in 1995 and was the primary reason the licensee exceeded it's 1995

annual collective dose goal of 283 person-rem by approximately 129 person-rem. This was basically a maintenance and operations problem adversely impacting the station ALARA program.

Report Details

Summary of Plant Status

Unit 1

Unit 1 operated at full power from the beginning of the inspection period until February 22, when a manual trip was initiated during a unit shutdown. The shutdown was the result of a dropped and unrecoverable CEA. The unit achieved criticality on February 24 and returned to full power operations on February 25. On March 26, the unit was downpowered for waterbox cleaning. The unit returned to full power on March 29 and remained at full power through the end of the inspection period.

Unit 2

Unit 2 operated at essentially full power throughout the inspection period.

I. Operations

O1 Conduct of Operations (71707, 61726, 93702)

O1.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 1 TS required shutdown/trip

On February 22, at 8:55 a.m., Unit 1 began FLCEA testing per OP 1-0110050, "Control Element Assembly Periodic Exercise." This test is performed at least once every 92 days in modes 1 or 2 as required by TS 4.1.3.1.2 to verify operability of each full-length CEA not fully inserted. Per the test methodology, each full-length CEA is inserted at least 7.5 inches. All CEAs in Groups 1, 2 and 3 were successfully exercised. At 10:03 a.m. when operators were preparing to exercise CEA #57 (the last CEA in Group 4), CEA #20 (Group 2) dropped. Power initially fell to 93 percent. Operators responded promptly by matching turbine load per ONOP 1-0110030, "CEA Off-Normal Operation and Realignment." Efforts to recover CEA #20 were unsuccessful and, consequently, a Unit 1 shutdown per TS 3.0.3 and NOUE occurred.

The inspector was present in the control room and observed the decision-making process leading to a unit shutdown. Initially, Unit 1 entered TS 3.1.3.1 action statement e. which stated "With one full length CEA

misaligned from any other CEA in its group by 15 or more inches, operation in Modes 1 and 2 may continue provided that the misaligned CEA is positioned within 7.5 inches of other CEAs in its group within the time constraints shown in Figure 3.1-1a." Figure 3.1-1a allowed 60 minutes to restore CEA group alignment.

At 10:30 a.m., when it became clear that CEA #20 was not recoverable, action statement f. was entered. Action statement f stated:

> "With one full length CEA misaligned from any other CEA in its group by 15 or more inches beyond the time constraints shown in Figure 3.1-1a, reduce power to less than or equal to 70 percent of rated thermal power prior to completing action f.1 or f.2.
>
> f.1 Restore the CEA to operable status within the specified alignment requirements, or
>
> f.2 Declare the CEA inoperable and satisfy the shutdown margin requirements of Specification 3.1.1.1. After declaring the CEA inoperable, operation in Modes 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6 provided:
>
> a) Within one hour the remainder of the CEAs in the group with the inoperable CEA shall be aligned to within 7.5 inches of the inoperable CEA while maintaining the allowable CEA sequence and insertion limits shown on Figure 3.1-2; the thermal power level shall be restricted to Specification 3.1.3.6 during subsequent operation period.
>
> b) The shutdown margin requirement of Specification 3.1.1.1 is determined at least once per 12 hours."

The shutdown margin calculation was performed using OP 1-0110055, "Surveillance Requirements for Shutdown Margin, Modes 1 and 2 (Critical)." There was a discussion between operations and reactor engineering on whether the more restrictive PDIL of Unit 1's Plant Physics Curve C.5 as referenced for an immovable CEA were applicable. If so, this would require reducing power to less than approximately 34 percent within 1 hour. It was concluded that immovable referred to a withdrawn stuck CEA and was not applicable in this case. However, TC #1-96-33 was issued to document this clarification.

At 12:00 p.m., Unit 1 entered TS 3.0.3 since CEA #20 could not be realigned within the one hour allowed for continued operation. At 12:05 p.m., the NPS declared an NOUE based on Increased Awareness due to a

Shutdown required by Technical Specifications for which the required shutdown is not reached within the action limits. Since TS 3.1.3.1 had no explicit requirement or allowed time associated with a single inoperable CEA not aligned within 7.5 inches of the other CEAs in the group, the licensee's entry into TS 3.0.3 was appropriate. However, the basis for the declaration of an NOUE was incorrect. TS 3.0.3 stated "When a LCO is not met, except as provided in the associated action requirements, within one hour action shall be initiated to place the unit in a mode in which the specification does not apply by placing it, as applicable in at least hot standby within the next six hours." An NOUE would have been required if the unit was not in hot standby within seven hours. The inspector reviewed EPIP 3100022E, "Classification of Emergencies," and concluded that the NOUE was voluntary based on criteria 6.A. for Unusual Event, "Emergency Coordinator's Judgement that plant conditions exist which warranted increased awareness on the part of the operating staff and/or local authorities."

During the shutdown at approximately 30 percent power with only the "1B" MFW pump in service, operators observed fluctuations in SGWLs. An attempt to take manual control of the "1A" MFRV and prevent overfeeding the SG was unsuccessful. The NPS directed operators to manually trip the unit at approximately 26 percent power. Various equipment problems were encountered following the trip and during restart which are discussed in paragraphs M2.1 of this report.

At 1:30 p.m., the NOUE was exited with Unit 1 stable in hot standby (mode 3).

The inspector observed the operators respond to the dropped CEA #20 and implement the Emergency Plan. Operator response was considered excellent. All required actions were promptly executed with a minimum of direction provided by supervision.

The inspectors reviewed the post trip package which was, with the exceptions noted in paragraph M1.2, considered acceptable.

On February 23, at 9:00 a.m., Unit 1 commenced a startup. During withdrawal of Shutdown Bank "A" for an operability check, CEA #47 dropped from 12 inches to the bottom. At 11:55 a.m. the remaining Shutdown Bank "A" CEAs were driven to the bottom and the startup terminated. A containment entry was made for I&C troubleshooting of CEA #47 problem. See paragraph M1.2 of this report for a discussion of CEA troubleshooting issues.

Unit 1 completed a second startup and was returned to service on February 24. See paragraph 01.3 of this report

01.3 Unit 1 Switchyard Electrical Misalignment

RI 96-A-0039

On February 24, at 2:15 a.m., Unit 1 commenced a second startup with entry into Mode 1 on February 25, at 12:33 a.m. After closing the Main Generator Output Breaker during synchronization with the Grid, operators received annunciator C-29, "GENERATOR MOTORING," and noted that the synchroscope continued to rotate. The Main Generator Output Breaker was opened to prevent a backup lockout and Generator trip. The licensee determined that both Unit 1 Generator Disconnects, 8G27 and 8G29, were open (the Main Generator disconnects are opened per procedure if the unit is off-line more than 4 hours by either OP 1-0030125, "Turbine Shutdown - Full Load to Zero Load," step 8.29 or, in this case, 1-EOP-02, "Reactor Trip Recovery," step 20). TC 1-96-036 to OP 1-0030124, "Turbine Startup Zero to Full Load," was issued to restore the switchyard lineup following which, the Main Generator was successfully synchronized to the Grid.

The inspector had several concerns regarding the switchyard misalignment:

- No STAR or IHE was generated documenting that an inadequate procedure was identified during use which resulted in an anticipatory alarm that a generator backup lockout would occur. An Operations Department Problem Report (Data Sheet 7) was completed, however, AP No. 0010120 Rev 79, "Conduct of Operations" step 8.D states that "Problem reports should be utilized to supplement other reporting and corrective processes; i.e., LER, IHE."

- Completed OP 1-0030124 did not document any repeated steps following the initial failure to synchronize to the grid as reported in the RCO log entry of 3:55 a.m.

- OP 1-0030124 was revised in October 1995 adding a NOTE before step 8.1 which stated "If startup of the turbine is a result of a turbine trip OR Turbine shutdown and the cause has been corrected, Then the subsequent restart can be commenced with Section 8.3." This revision failed to provide a separate verification that the Unit 1 Generator Disconnects, 8G27 and 8G29, were CLOSED as was accomplished in step 8.1.4 if steps 8.1 and 8.2 were not performed.

- TC 1-96-036 added the above verification as step 8.3.1 resequencing all other steps in section 8.3. Since the completed OP 1-0030124 did not document any repeated steps, the inspector concluded that this step was performed out-of-sequence.

- Completed EOPs are discarded after use since only blocks are checked with no signatures. This precludes an independent verification that

a particular step was or was not performed.

The licensee initiated a Data Sheet 7 (Operations Department Problem Report) to document this event. Unit 1 completed the power ascension without further incident.

02 Operational Status of Facilities and Equipment (71707)

02.1 Engineered Safety Feature System Walkdowns

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following ESF systems:

a. During the week of March 4, the inspector performed a walkdown of the Unit 1 Containment Spray System. This consisted of a review of the following procedures and engineering drawings and verification of current system alignment including:

- OP 1-0420020, Rev 31, "Containment Spray - Initial Valve Alignment"
- ONOP 1-0030131, Rev 62, "Plant Annunciator Summary"
- Applicable Engineering Drawings

The following discrepancies were noted:

(1) OP 1-0420020, Rev 31, "Containment Spray - Initial Valve Alignment"

- V07230 was listed as Locked Closed, however, no lock was installed.
- V07163 and V07191 positions were given as Closed although they were Administratively Controlled as Locked Closed per AP 1-0010123 and did have locks installed.
- Precaution 4.1 stated that "Certain valves in this system are aligned for shutdown cooling and must not be repositioned without considering the impact upon shutdown cooling. These valves will be designated." The following valves were not designated as shown in OP 1-0010123 (sheets 43, 46, and 52):
  - V07161 (sh. 43), V07164 (sh. 46) and MV-07-3A, MV-07-3B (sh. 52) were designated "Locked Closed when Shutdown Cooling in service."
  - V07130 was Locked Closed during cooldown and

should have been annotated by Note 2, "These valves are positioned as part of heatup and cooldown."

- MV-07-1A and MV-07-1B were annotated with Note 2, however, they were not repositioned Locked Closed per OP 1-0030127 (Cooldown) and OP 1-0030121 (Heatup - sh. 14, 15) only ensured that these valves were Open or Locked Open.

- V07160 had no valve tag or other identifier.

- V07224 and V07225 descriptions were not consistent with AP 1-0010123.

- SE-07-1A, SE-07-2A, SE-07-1B, SE-07-2B descriptions were not consistent with RTGB-106 tag identification.

(2) ONOP 1-0030131, Rev 62, "Plant Annunciator Summary"

- Annunciator R-2 CAUSTIC TANK PRESS HIGH

  Setpoint 7 psig was incorrect. PIS-07-7 was set at 8 psig increasing (TEDB).

- Annunciator R-12 CAUSTIC TANK LEVEL LOW/LOW-LOW

  Setpoint in TEDB was given as 65" decreasing and 3" decreasing. Gallonage was from strapping table which was not referenced. The Sensing Element LIS-07-7D only closed one of four NaOH admission valves. The other three closed on a Caustic Tank Level Low-Low setpoint of 3" decreasing from LIS-07-7A, LIS-07-7B and LIS-07-7C.

- Annunciator R-21 CONTMT SPRAY HEADER A PRESS LOW

  Sensing element was identified as PT-07-3A, rather than PIS-07-3A appearing on CWD 362

- Annunciator R-22 CONTMT SPRAY HEADER B PRESS LOW

  Sensing element was identified as PT-07-3B rather than PIS-07-3B appearing on CWD 362

- Annunciator R-31 CONTMT SPRAY FCV-07-1A FAIL TO OPEN

  Setpoint of 10 seconds after OPEN signal was not shown

on CWD 289. CWD showed alarm after 15 seconds.

- Annunciator R-32 CONTMT SPRAY FCV-07-1B FAIL TO OPEN

  Setpoint of 10 seconds after OPEN signal was not shown on CWD 289. CWD showed alarm after 15 seconds.

(3) Engineering Drawing

- 8770-G-088, "Flow Diagram Containment Spray and Refueling Water Systems," Rev 31

  LT 07-7A is shown isolated by V07237 and V07244. Field verification found junction box with cable to LT labelled as LT 07-7C.

  LT 07-7C is shown isolated by V072387 and V07243. Field verification found junction box with cable to LT labelled as LT 07-7A.

  V07223, V07230 and V07233 were not shown as Locked Closed.

  V07152 1B SDC HX Outlet vent was installed at the bottom of the pipe, thus appearing unable to vent the pipe. In contrast, V0718 1A SDC HX Outlet vent was installed on the top of the pipe.

(4) OP 1-0010123, Rev 100, "Administrative Control of Valves, Locks and Switches"

- V07223, V07230 and V07233 were Locked Closed in OP 1-0420020, however, none were Administratively Controlled per AP 1-0010123..

- V07145, V07130, V07255, V07257 (sh. 72), and V07271, V07272 (sh. 74) were <u>not</u> designated "Valves Locked Closed if Shutdown Cooling in service or less than 1750 psia RCS Pressure" as was done for Unit 2.

- MV-07-3A and MV-07-3B (sh. 43, 46 and 52) appeared in Appendix "F." TC# 2-95-683 transferred the functionally equivalent valves MV-07-3 and MV-07-4 from Appendix "F" to Appendix "L." MV-07-3A and MV-07-3B were also repositioned by OP 1-0030127 (Cooldown). This was identified as an inconsistency between Units.

b. During the week of March 11, the inspector performed a walkdown of the Unit 2 Containment Spray System. This consisted of a review of the following procedures and engineering drawings and verification of current system alignment including:

- OP 2-0420020, Rev 19, "Containment Spray Initial Valve Alignment"
- ONOP 2-0030131, Rev 50, "Plant Annunciator Summary"
- Applicable Engineering Drawings

The following discrepancies were noted:

(1) OP 2-0420020, Rev 19, "Containment Spray Initial Valve Alignment"

- V07106, V07390 through V07393, V07191 and V07163 positions were given as Closed although they were Administratively Controlled as Locked Closed per AP 2-0010123.

- MV-07-3 and MV-07-4 positions were given as Open although they were Administratively Controlled as Locked Open by keyswitch at RTGB-206 per AP 2-0010123.

- V29429 and V29430 (Nitrogen Supply) were not included in initial lineup as was done for Unit 1.

- V3868 2A SDC HX Outlet Vent was omitted from lineup.

- Valves whose positions would be verified by control room indication, e.g. SE-07-3A, SE-07-3B, MV-07-1A, MV-07-1B, MV-07-3, MV-07-4, etc., were not identified as was done for Unit 1.

- Precaution 4.1 stated that "Certain valves in this system are aligned for shutdown cooling and must not be repositioned without considering the impact upon shutdown cooling. These valves will be designated." The following valves were not designated as shown in OP 2-0010123 (sheets 51, 54, 84 and 85):

  - V07162 (sh. 51) and V07165 (sh. 54) were designated "Locked Closed when Shutdown Cooling in service."

  - V07145, V07130 (sh.85), and SH07248, SH07252, SH07253 (sh.84) were designated "Valves Locked

Closed if Shutdown Cooling in service or less than 1750 psia RCS Pressure."

(2) ONOP 2-0030131, Rev 50, "Plant Annunciator Summary"

- Annunciator S-10 HYDRAZINE TK LEVEL LO

  Setpoint of 35.5 inches was incorrect. PCM 109-294 issued 9/16/94 changed setpoint to 36.7 inches. TEDB has no reference to this setpoint.

- Annunciator S-20 HYDRAZINE TK LEVEL LO-LO

  Auto Action that Hydrazine pumps 2A/2B stop was unrelated to Sensing Element LIS-07-9. Sensing Elements LS-07-10A and LS-07-10B stopped Hydrazine Pumps 2A and 2B and closed SE-07-3A and 3B at the same setpoint as LIS-07-9.

(3) Engineering Drawing

- 2998-G-088, "Flow Diagram Containment Spray and Refueling Water Systems," Rev 23, Sh 1

  V07101 (B6) and V07106 (D4) were shown as Closed instead of Locked Closed.

  V07334 (F5) and V07335 (G5) were shown as Open instead of Locked Open.

  "LOW LEVEL STOPS PUMP & CLOSES VALVE" (F1 and F3) was incorrect. The note should have read "LOW-LOW LEVEL STOPS PUMP & CLOSES VALVE."

- 2998-G-088, "Flow Diagram Containment Spray and Refueling Water Systems", Rev 23, Sh 2

  V07390 through V07393, V07191 and V07163 (C2-3, D2-3) were shown as Closed instead of Locked Closed.

(4) OP 2-0010123, Rev 69, "Administrative Control of Valves, Locks and Switches"

- §6.1 incorrectly references St. Lucie Unit 1 UFSAR.

- TC# 2-95-683 transferred valves MV-07-3 and MV-07-4 from Appendix "F" to Appendix "L" and stated the reason for

the change, in part, as "MV-07-3&4 are to be closed until mode 3/1750 psia," however, the change failed to annotate the position with "#", "Valves Locked Closed if Shutdown Cooling in service or less than 1750 psia RCS Pressure" as appears on sh. 84.

- Note "#," "Valves Locked Closed if Shutdown Cooling in service" on sh. 85 was not complete. It should have included "or less than 1750 psia RCS Pressure" - see OP 2-0030127 (Cooldown).

- TC# 2-95-688, Section G, "Authorization Date" left blank.

The licensee documented the inspectors findings on STAR 951515 and PMAI-96-03-402 and 403.

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected. The inspectors identified two areas of concern as a result of these walkdowns:

a. On Unit 1, the licensee's failure to identify and correct during previous system alignments the misidentification of LT 07-7A and LT 07-7C as noted in paragraph 02.1.a(3) above.

b. On Unit 2, the licensee's failure in implementing PCM 109-294 Attachment 1 (TEDB) and the Other Affected Documents "Plant to identify any affected procedure which may require revision due to this modification, including the annunciator procedures" as noted in paragraph 02.1.b(2) above.

02.2 Equipment Clearances

The inspectors independently verified the following equipment clearances for correctness:

a. 1-96-02-125 on Feed Reg Backup Air - This clearance consisted of four tags isolating the Backup Air supplies to FCV-9011, FCV-9021, 1A MSIV Accumulator and the 1B MSIV Accumulator, which were no longer in use. All tags were in place and the valves were in the correct position. During verification, the inspector identified two discrepancies to the ANPS and the Work Control Center:

(1) Two of the tags were weathered and needed to be replaced.
(2) Twenty Administratively Controlled valves, i.e. all of the "1A" and "1B" MSIV valves listed in Appendix N of AP 1-0010123

Rev 100, "Administrative Control of Valves, Locks and Switches," had locks installed, however, none have position placards attached as required by AP 0010143 Rev 11, "Labeling/Tagging of Plant Equipment," step 8.1.11. Similar valves on Unit 2 were removed as Administrative Controlled valves by TC #2-95-688 issued December 29, 1995 and did not have locking devices installed.

b. 1-96-03-132 on replacement of HVA-3B - This clearance consisted of two tags isolating the electrical supply to the HVA-3B. Both tags were in place and the breakers in the correct position.

c. 1-96-03-134 on MV-09-14 Cross-Tie between AFW Pump "1B" discharge to SG "1A" - This clearance consisted of one tag isolating the electrical supply. The tag was in place and the breaker in the correct position.

d. 2-96-03-023 on Condensate Pump "2B" - This clearance consisted of two tags; one aligning the power supply to the "2C" Condensate Pump and the other isolating the suction side of the pump. Both tags were in place and the transfer switch and the suction valve in the correct positions.

e. 2-96-03-102 on the New Fuel Storage Area Crane - This clearance consisted of one tag isolating the electrical supply. The tag was in place and the breaker in the correct position.

The inspectors noted that Operations appears to be improving in the area of attention to detail in clearance preparation.

03 Operations Procedures and Documentation (61726)

03.1 OP 3200051, Rev 16, "At Power Determination of Moderator Temperature Coefficient and Power Coefficient".

This procedure provided the method for determining MTC at power and was performed per TS 4.1.1.4.2.c which required verification that MTC was within TS 3.1.1.4 limits "At any THERMAL POWER, within 7 EFPD after reaching a RATED THERMAL POWER equilibrium boron concentration of 300 ppm."

On March 4, Unit 1 commenced the MTC test. During insertion of CEA #1 from 105 inches to 104 inches to maintain delta T power at 100 percent, CEA #1 dropped. Operators entered ONOP 1-0110030, "CEA Off-Normal," and took the required actions to reestablish CEA alignment. The MTC test was exited and a STAR written to investigate and correct the cause of the dropped CEA. Vendor representatives were called onsite to evaluate the

previous visicorder readings taken on CEA #1 following replacement of the timer card on March 2 (NPWO 63/5079).

After a discussion with Operations, I&C (in conjunction with an independent vendor review) concluded, after performing a system evaluation and procedural review, that the CEA #1 drop may have been a result of "operator technique," i.e. allowing the Rod Control System to stop inward CEA motion before depressing the CEA Motion Inhibit (CMI) bypass to resume inward motion and releasing the CMI bypass switch prematurely after stopping CEA inward motion. TC #0-96-031 to the MTC procedure provided clear instructions to operators on use of the CMI bypass pushbutton momentary switch to preclude dropping a CEA.

On March 6, the inspectors attended a management review meeting where a plan of action was adopted prior to recommencing the MTC test on March 7. It was decided at this meeting that CEA #1 would be declared INOPERABLE during connection and removal of test equipment. This decision was based on a voluntary entry into TS 3.1.3.1 for planned maintenance should the CEA drop.

On March 7, the inspector attended the pretest brief held in the Unit 1 control room. The brief was thorough and included the management decision to declare CEA #1 INOPERABLE during installation and removal of test equipment.

The inspector remained in the control room during performance of the test and made the following observations:

- CEA #1 was declared INOPERABLE during installation and removal of test equipment with no Equipment Out-Of-Service Log entry made.

  CEA #1 was paralleled to CEA #68 during installation and removal of test equipment. This ensured that loosening terminal block connections could not inadvertently cause CEA #1 to drop. However, any attempt to move a paralleled CEA would result in a drop since a paralleled CEA receives power to the Upper Gripper coil only. Thus, operators logged CEA #1 INOPERABLE and entered TS 3.1.3.1.c which stated:

  "With one full length CEA inoperable due to causes other than addressed by Action a above, but within its above specified alignment requirements and either fully withdrawn or within the long term steady state insertion limits if in CEA group 7, operation in MODES 1 and 2 may continue."

  TS 3.1.3.1.a described "inoperable CEAs" as those CEAs being immovable as a result of excessive friction or mechanical

interference or known to be untrippable. Thus, CEA #1 was not inoperable per TS, as it both satisfied alignment criteria and was mechanically free to perform it safety function.

Following a discussion with the ANPS, the inspector concluded that the failure to complete an Equipment Out-Of-Service Log entry was a cognitive error attributable to several factors:

- The decision to declare CEA #1 INOPERABLE and enter TS 3.1.3.1.c for installation and removal of test equipment was briefed as part of the test evolution and entirely voluntary.

- TS 3.1.3.1.c had no action times associated with an LCO.

For the above reasons, the inspector concluded that operators viewed this as being controlled within the context of an infrequently performed test or evolution and forgot the administrative requirement for entry in the Out-Of-Service Log. Although the requirement to complete an Equipment Out-Of-Service Log entry was not met, the inspector attributed the cause to simple cognitive error with no safety significance. The inspector's evaluation of safety significance is based on:

- RCO log entries documenting installation and removal of test equipment for CEA #1 which clearly identified when the CEA was considered inoperable.

- CEA #1 remained capable of performing its safety function at all times.

- Independent verification of I&C jumper suspect.

  I&C installed a jumper per step 8.5.1 of the test procedure in order to clear CWP and allow CEA withdrawal to avoid a trip. The inspector observed both the installation and somewhat informal independent verification. The technician who performed the independent verification pointed out the location where the jumper was to be installed before installation and remained at the instrument cabinet during installation. The Maintenance Manager, who was in the control room at the time, questioned the adequacy of the independent verification and had an I&C Supervisor reverify the jumper. The jumper was reverified to be properly installed. The inspector found the Maintenance Manager was proactive in recognizing this potential error.

- Verification step in test procedure signed in error.

Step 8.4 verified that RCS boron concentration was stable based on two consecutive samples taken at 15 minute intervals with a difference between the RCS and pressurizer of less than or equal to 25 ppm. The Test Specialist had verified this step as complete with three samples recorded at 30 minute intervals. The inspector brought this to the attention of the NPS to ensure that an additional two samples would be taken per the 15 minute criteria.

The inspector questioned the Test Specialist the following day regarding this matter. The Test Specialist stated that it was his intention to request additional RCS samples as required and acknowledged that he had signed this step in error. The inspector reviewed several completed MTC procedures including the aborted one performed on March 4, and concluded that the Test Specialist was aware of the 15 minute interval requirement.

In general, the inspector concluded that this infrequent test was performed satisfactorily. However, it should be pointed out that neither the Test Specialist or Management Designee assigned to provide Management Oversight identified the above three discrepancies. The inspector reviewed the completed MTC test procedure and found no discrepancies.

04 Operator Knowledge and Performance (71707, 71715)

04.1 Failure to Follow Conduct of Operations Procedure

IR 95-03, which addressed an overdilution event on Unit 1, noted that operators had not employed the appropriate procedure in performing the subject dilution. The inspectors noted that AP 0010120, "Conduct of Operations," Appendix M, "Procedural Compliance and Implementation," stated that procedures would be implemented and complied with by operators and described tasks, considered to be "skill of the trade," which did not require a procedure in-hand during performance of the specified activities. The inspectors noted that boron concentration control was not one of the evolutions considered to be "skill of the trade." The failure of the operator performing the dilution at the time to employ OP 1-0250020, "Boron Concentration Control - Normal Operation," was cited as a violation of AP 0010120.

On February 22, while touring the Unit 2 control room, the inspector observed operators adding boric acid to the VCT for temperature control. At the completion of the evolution, the inspector noted that the operators had not employed a procedure for the evolution. The inspector questioned the ANPS overseeing the activity as to the need to employ the procedure. A review of AP 0010120 indicated that boron concentration control was still not considered "skill of the trade."

The licensee investigated the issue and reported that the subject procedure had been out and available previously in the shift. The licensee determined that the procedure had been put away sometime during the shift in preparation for tours by NRC senior managers, who were onsite for the public SALP meeting conducted on that date. The inspector concluded that the failure of the operators to employ OP 2-0250020, "Boron Concentration Control - Normal Operation," constituted a violation of AP 0010120, "Conduct of Operations." However, as the licensee had not had an opportunity to describe and execute their corrective action to the violation described in IR 96-03, the incident is cited as an additional example of EEI 335,389/96-03-01, "Operators Failed to Follow Procedures for Boron Dilution, Watch Turnover, Procedure Adherence, and Event Reporting."

04.2 Unit 1 Containment PIG Rendered OOS Due to Personnel Error

Following the Unit 1 trip of February 22, a number of containment entries were made to troubleshoot CEAs. In preparation for one such entry, an HP technician was dispatched to obtain a grab sample of the containment atmosphere on February 22, at 1:55 p.m. The methodology for obtaining the sample involved attaching a removable air sampling device to quick disconnect fittings which placed the device in a parallel path to the air flow moving through the PIG unit. A valve (procedurally designated as valve 3) located between the quick connects was then to be throttled closed to force the air flow through the sample device at a predetermined rate. A sample was then to be taken for a minimum of 30 minutes, at which time the throttle valve was to be returned to its open position and the sample device was to be isolated at the quick disconnects and removed from the unit.

When the HP technician performed the sample, he failed to return the throttle valve to its open position. The result was that flow through the PIG was reduced to approximately 15 percent of the intended value, rendering the PIG inoperable. The licensee's investigation of the event revealed that the HP technician failed to employ HPP-22, Rev 2, "Air Sampling." Step 7.5.1.R required that, upon completion of the sampling, valve 3 be returned to the full open position. In fact, the subject step was proceeded by a caution statement stating that valve 3 must be returned to the full open position. The failure of the HP technician to employ the governing procedure for obtaining air samples is one example of a violation (VIO 335/96-04-01, "Failures to Follow Procedures Lead to Unit 1 Containment PIG Inoperability").

The PIG remained in its inoperable state until February 24, when a chemistry technician performing an unrelated task noted the indicated flow through the PIG at a value much lower than normal (a fraction of one scfm, vice 2.5 to 3.5 scfm required by procedure), which resulted in the

identification of the PIG's inoperability and its return to service. During that time, SNPOs recorded the lower-than-normal flow values during logtaking rounds once per shift. Operators employed data loggers (small hand-held computers) to take logs, and when a given parameter was sensed to be out-of-specification by the computer, the operator was prompted to enter the data again to verify that the out-of-specification value was, indeed, the intended value. In the case of PIG air flow, SNPOs logged the data twice each round without pursuing the cause for the low reading.

AP 0010120, Rev 79, "Conduct of Operations, Appendix F, "Log Keeping," stated, in part, "Log readings shall be compared to previous readings to detect abnormal trends or conditions and verified to be within the minimum and maximum values for that parameter. All log readings outside the min/max values shall be circled with reasons stated for abnormal readings..." The failure of SNPOs to identify the low flow condition of the Unit 1 containment PIG and to provide reasons for the observed performance is an example of a violation (VIO 96-04-01, "Failures to Follow Procedures Lead to Unit 1 Containment PIG Inoperability"). Additionally, the direction that out-of-specification values should be "circled" indicated that the procedure was not current, as the direction was a clear reference to paper logs (the predecessor of the data loggers), which had not been employed for some time by SNPOs.

On February 24, the unit was taken critical, resulting in a change from Mode 3 to Mode 2. TS 3.0.4 stated that "Entry into an OPERATIONAL MODE or other specified applicability condition shall not be made when the conditions of the Limiting Condition for Operation are not met..." Unit 1 entered Mode 2 on 5:13 a.m. on February 24 with the containment PIG inoperable. TS 3.4.6.1 requires the PIG to be operable in mode 2. As a result of the violations detailed above, the licensee transitioned from Mode 3 to Mode 2 in contradiction of TS 3.0.4.

The inspectors concluded that a number of barriers to failure were breached in this event. The specific actions relating to those barriers included:

- An HP technician performed an activity without availing himself of the appropriate procedure
- The HP technician failed to properly reposition a valve
- SNPOs failed, on multiple opportunities, to determine the cause for out-of-specification log readings
- SROs reviewing log data did not identify the out-of-specification values
- The Conduct of Operations procedure appendix which discussed log taking was out-of-date, with no current methodology describing how to identify out-of-specification values in the new, "paperless," logtaking environment.

- A low flow alarm setpoint for the PIG appeared to be set nonconservatively, as it was based on a no-flow, rather than low flow, condition (see discussion of LER-specified corrective actions below)

The inspector reviewed the licensee's discussion of the event in LER 335 96-003-00, "Containment Particulate and Gaseous Monitor Out of Service Resulting in a Condition Prohibited by Technical Specifications Due to Personnel Error." In the LER, the licensee described corrective actions which included:

- Disciplining the HP technician involved in the event.
- Enhancement of both units' logs to include a written explanation for out-of-specification readings.
- Incorporating sign-offs in HP procedures for actions involving the manipulation of plant equipment.
- Reviewing the event with HP personnel emphasizing procedural compliance.

The inspector reviewed Rev 3 to HPP-22, and noted that the new revision included requirements that the control room be notified at the beginning and end of containment sampling (new requirements) and that independent verifications be made of valve positions following sampling. Similar changes were made to the procedure for Unit 2 sampling.

The inspector discussed the event with the Operations Supervisor and asked whether, in the past, the PIGs were declared inoperable when sampling occurred and was informed that they had not, but that they would in the future. The inspector concluded that the licensee's corrective actions for the short term appeared adequate; however, the licensee may not have adequately bounded the issue in the LER's treatment. Specifically, the LER did not discuss what other pieces of equipment were operated by personnel other than operations which may be susceptible to similar errors, nor did the licensee discuss what actions, if any were taken to ensure that SNPOs understand the importance of questioning out-of-specification data. The inspector will follow these issues ir closing the subject LER.

In summary, the inspector found that the undetected inoperability of the subject component was the result of not employing a procedure while performing a grab sample. The condition was extended in time due to inadequate logtaking on the part of non-licensed operators and inadequate review of the logs taken. As a result of these failures, a violation of TS occurred when a reactor startup was performed with the component OOS. Additional weaknesses included a logging procedure which was not up-to-date, and an historical failure on the part of Operations to declare the containment PIG OOS when grab sampling was taking place.

04.3 Control Room Observation

The inspector observed control room operations in both units at various times during the inspection period of March 25-29, 1996. Observation of steady state plant operations and shift turnover were conducted to determine if the operators were operating the plant in accordance with plant procedures and guidelines. The inspector compared observed operator performance to the requirements and guidelines for operator performance in AP 0010120, Rev 80, "Conduct of Operations." This procedure covered topics such as procedure compliance and implementation, communications, crew relief/shift turnover and log keeping among others. To fulfill one of the corrective actions to the recent overdilution event (see IR 96-03), Operations Management reinforced through operating crew briefings their expectations in "Conduct of Operations." Particular emphasis was placed on notification of Operations Management, log keeping, focus on reactivity changes, and the short term turnover process. In a letter to the NRC dated March 6, 1996, the licensee stated that the above stated corrective action was complete.

Operator conduct in the control room was generally business-like and professional. The inspector observed no unauthorized reading material in the control room and noted that the majority of conversations between operators concerned plant operation. Plant policy concerning communications between operators was stated in AP 0010120, Appendix L, "Communications," and provided guidelines for face-to-face communications. The appendix stated that face-to-face communications should include repeat-backs with confirmation (three-way communications). Face-to-face communication between the operators was rarely conducted in accordance with this guidance. The inspector observed one conversation during which a repeat-back was used, and this was not followed by a confirmation.

The RCO maintained a chronological log to document events and operator actions of importance. The requirements for maintaining the chronological log were stated in AP 0010120, Appendix F, "Log Keeping." Among the items that were required to be entered in the RCO chronological log were reactivity manipulations and abnormal conditions related to turbine-generator auxiliary systems. The inspector observed the Unit 1 RCO perform two RCS dilutions of 300 gallons each on March 27, 1996. A review of the RCO logs the next day indicated that not only were the two observed reactivity manipulations not entered into the RCO chronological log as required, but there were no log entries for dilutions. The initial log entry made when assuming the shift included the statement "Board RCO diluting periodically to maintain RCS temperature." Discussions with the ANPS indicated that he thought this general log entry was adequate to comply with log keeping requirements. However, the shift before and the shift after logged two and seven dilutions, respectively, in addition to making a general log entry addressing the need to dilute more than normal.

The shift turnover meeting between the off-going day shift and the on-coming peak shift on March 27 included information that the Unit 1 main generator hydrogen cooling system pressure needed to be increased due to loss from a slow leak. When the ANPS was asked whether this should be conducted using the Normal Operating procedure or the Off-Normal Operating Procedure, the ANPS expressed no preference for either and told the SNPO to choose one. The inspector determined the next day from the SNPO logs that the Unit 1 main generator hydrogen pressure was increased at approximately 6:30 p.m. The SNPO logs did not say which procedure was used, however, discussions with the operators indicated that the ONOP for loss of main generator hydrogen was typically used since it did not require an extensive valve line-up and could be conducted in a minimal amount of time. The next day, the inspector reviewed the peak shift RCO logs and determined that the Unit 1 main generator hydrogen pressure increase was not entered into the RCO chronological log as required. The failure to enter the above three events into the RCO Chronological as required is identified as a violation (VIO 50-335/96-04-02, "Failure To Make Required Log Entries").

At the exit interview, the plant manager and operations manager stated that it was not their expectation that the operators log every reactivity manipulation when frequent manipulations were required to balance a transient. They stated that since the initial shift log entry had included the statement "Board RCO diluting periodically to maintain RCS temperature," there was no need to log each individual dilution.

Based on the above, the inspector concluded that implementation of AP 0010120, "Conduct of Operations," was spotty and that plant management and operations would benefit from a more rigorous implementation of the procedure.

04.4 Inoperable EDG Due to Operator Error

On January 5, in IHE Number 96-02, the licensee identified an event in which improper valve line up for recirculating the 1A DFOST occurred. An improper valve line-up occurred following a request made by chemistry to operations to place the 1A DFOST on recirculation for sampling. The subject valve lineup resulted in the inadvertent inoperability of the EDG. Based on the review of the event there were procedure violations committed by operations, communication problems and training deficiencies.

Details of the events are as follows. The Unit 1 RCO was contacted at 1:30,a.m. by chemistry to place the 1A DFOST on recirculation. The Unit 1 SNPO was contacted and asked to complete the task. There were no indications that the RCO directed the SNPO to perform the task according

to OP-1-2200050A, Rev 24, "1A Emergency Diesel Generator Periodic Test and General Operating Instructions," Appendix E (which provided the necessary guidance). The SNPO performed the function by closing the discharge of the DFO transfer pump (creating a flow path back to the DFOST via the pump's minimum flow line), as opposed to establishing the procedure-based lineup through DFOST cross-connect and truck fill piping (which would have allowed the DFO transfer pump to replenish the 1A EDG day tank, should such replenishment be necessary, thus ensuring EDG operability). The failure of the SNPO to establish the appropriate valve lineup for the DFOST recirculation is one example of a violation (VIO 50-335/96-04-03, "Failure to Follow Procedures While Placing EDG Fuel Oil Tank on Recirculation").

At 2:45 a.m., primary chemistry contacted the control room to determine the status of the 1A DFOST. The RCO contacted the SNPO concerning the completion of the task. The SNPO reported that the task had been completed since 2:00 a.m. There was no indication that the SNPO reported back to the control room that the task had been completed. Step 5.A.9 of Appendix A in Conduct Of Operations stated that the SNPO "Shall report promptly to the control room any equipment or valve manipulations so that the RCO will be aware of the current Plant Status." The failure of the SNPO to advise the control room of the completion of the assigned task is one example of a violation (VIO 96-04-03, "Failure to Follow Procedures While Placing EDG Fuel Oil Tank on Recirculation").

Licensed operators are typically trained to give instruction as to what procedure and section of the procedure should be completed in order to perform a task or evolution. In some instances the control room operator will give specific instruction on what must be done to complete a task. Following conversations with the licensee, the inspector confirmed that operators are trained to provide direction in the manner described above.

A review of documentation associated with the event and interview with licensee personnel indicated that the SNPO was not aware of procedural steps for placing the DFOST on recirculation. The fact that the SNPO was not aware of the procedural steps is an indication of training inadequacy or weaknesses. Also there is no indication that the SNPO was instructed by the licensed operator to perform the evolution per the applicable procedure until the licensed operator realized that the system was improperly aligned. Following conversations with training personnel the inspector confirmed that during operator licensing training, operators would give the procedure number and steps to be completed in order to perform the task. The procedure number and steps would be given to the individual performing the task. It was also confirmed that the individual completing the task would report back to the control room once the assigned task was completed. This is as example of both the licensed operator and the non-licensed operator not performing as trained.

05 Operator Training and Qualification (71715, 92901)

05.1 Licensed Operator Requalification Program

The inspector observed portions of licensed operator requalification training that were conducted during the inspection period. This included simulator training directed by the training department and a classroom session led by the shifts' Nuclear Plant Supervisor, the senior person on the shift.

The simulator session provided training and practice for the crew on a rapid plant downpower maneuver necessitated by jellyfish intrusion into the circulating water system. The downpower was followed by a loss of power to an electrical bus that caused loss of running circulating water pumps and presented conditions that eventually caused a reactor trip. The instructor emphasized conduct of operations issues to the crew and their importance to safe plant operation. He also provided a good synopsis of management expectations for professional conduct in the control room and of the need to improve from the level that currently exists. This meant that the requalification simulator training would, for future sessions, require the operators to practice and strictly adhere to the conduct of operations guidelines and requirements. Previous training had mostly focussed on the technical aspect of plant operations with little or no emphasis on conduct of operations. Log keeping was emphasized to the crew. However, the training department was unable to provide the operators with a laptop computer on which to keep logs the way they are kept in the plant. Proper communication techniques were emphasized by the instructor. However, during the scenario, these techniques were rarely used. During the downpower practice, the operators allowed some plant parameters to get outside of their normal operating limits. The instructor highlighted this to the operators and explained how their focus was on just completing the downpower and not accomplishing the downpower within the operating limits of the plant. Portions of the scenario were video taped to allow the operators the opportunity to self-critique themselves.

The inspector attended a classroom session that covered the "Conduct of Operations" procedure. The session was led by the shifts' NPS. He covered the new changes to the procedure and answered questions from the operators as necessary. Log keeping was covered during the session and the NPS specifically addressed the requirement to log reactivity manipulations. The session was scheduled for two hours. The NPSs' lecture took approximately one hour and the remaining hour was allotted for self-study.

The inspector reviewed the licensee's schedule for the previous and upcoming 24 month requalification periods. The current two year period is

scheduled to end in December 1996 and the previous period ended in October 1994. As of this review, the current 24 month period was scheduled to end approximately 26 months after the official end of the previous 24 month period. While the total amount of time of the current and previous requalification periods combined does not exceed 24 months, the amount of time from the end of the previous cycle to the end of the current cycle would exceed by two months that allowed by the regulations. This has occurred because the current requalification period has been modified to contain six cycles of training, instead of five cycles as were contained in the previous period. The licensee interpreted the regulation to allow all training to be conducted within a two year period that they could define. In defining their periods, they counted the two years from the beginning of the calendar year and not from the end of the previous cycle. The licensee is making arrangements to change their schedule to comply with the regulation while considering whether or not to seek an exemption from the regulation.

Within this area, no violations or deviations were identified.

05.2 Followup On Previously Identified Inspection Items

05.2.1 NRC Inspection Report 50-335,389/94-19 identified that the licensee could, by procedure, maintain an SRO licensed operator up to date in requalification training by requiring that operator to pass the required annual operating test at the RO level. This allowed some efficiency in the requalification training program since SRO licensed operators whose facility assigned position requires only an RO license could be examined in less time. The program required an SRO affected by this policy to receive special training and examination as an SRO prior to assuming a position that required and SRO license. This was identified as URI 50-335,389/94-19-02.

Since this inspection, the licensee has removed this from the governing procedure, Administrative Procedure 0005720, Licensed Operator Requalification Program, Rev 36. Currently, all licensed operators are required to be examined at the level of their NRC license. Since there were no significant examples of operators not receiving the proper examination and since the licensee has taken corrective action, this item is closed.

05.2.2 NRC Inspection Report 50-335,389/94-19 identified that AP 0005720, "Licensed Operator Requalification Program," allowed the Operations Supervisor to maintain an active license by virtue of filling the position. In accordance with 10 CFR 55.53(e), maintaining an active license requires that an operator be "actively performing the functions of an operator or senior operator." Since the Operations Supervisor had not filled a position that required a license, this

was identified as inspector followup item 50-335,389/94-19-03. The licensee has changed the governing procedure to address this inadequacy. The corrective action for this item is adequate and this item is closed.

05.2.3 NRC Examination Report 50-335/94-300 identified that the St. Lucie emergency operating procedures did not adequately provide guidance to the operators to ensure that a reactor coolant pump was tripped when reactor coolant system temperature dropped below 500°F. An RCP is tripped in this condition to prevent core uplift. The EOPs were changed to address this concern, however the change did not provide the guidance necessary to ensure consistent implementation of the requirement. The training department initiated a corrective action, number PM 96-03-212, to address this problem. The St. Lucie EOPs will undergo another revision which is scheduled to be completed by July 1996. This item will remain open until the EOPs have been revised.

08 Miscellaneous Operations Issues

08.1 (Closed) VIO 50-335/95-15-03, "Failure to Follow Procedure and Document Abnormal Valve Position in the Valve Switch Deviation Log"

[redacted]

The inspector reviewed the licensee's activities relating to the subject violation, which complicated a loss of RCS inventory event on August 10, 1995. The issue involved a series of floor drain valves (HCV 25-1/7) which had been left in the closed position following difficulties encountered while testing them prior to the arrival of Hurricane Erin. Operators had failed to log the fact that the valves were left shut in the Valve Switch Deviation log. When a relief valve lifted while placing Unit 1 on shutdown cooling, coolant collected in the Unit 1 pipe tunnel and was not removed via the floor drains due to the closed valves.

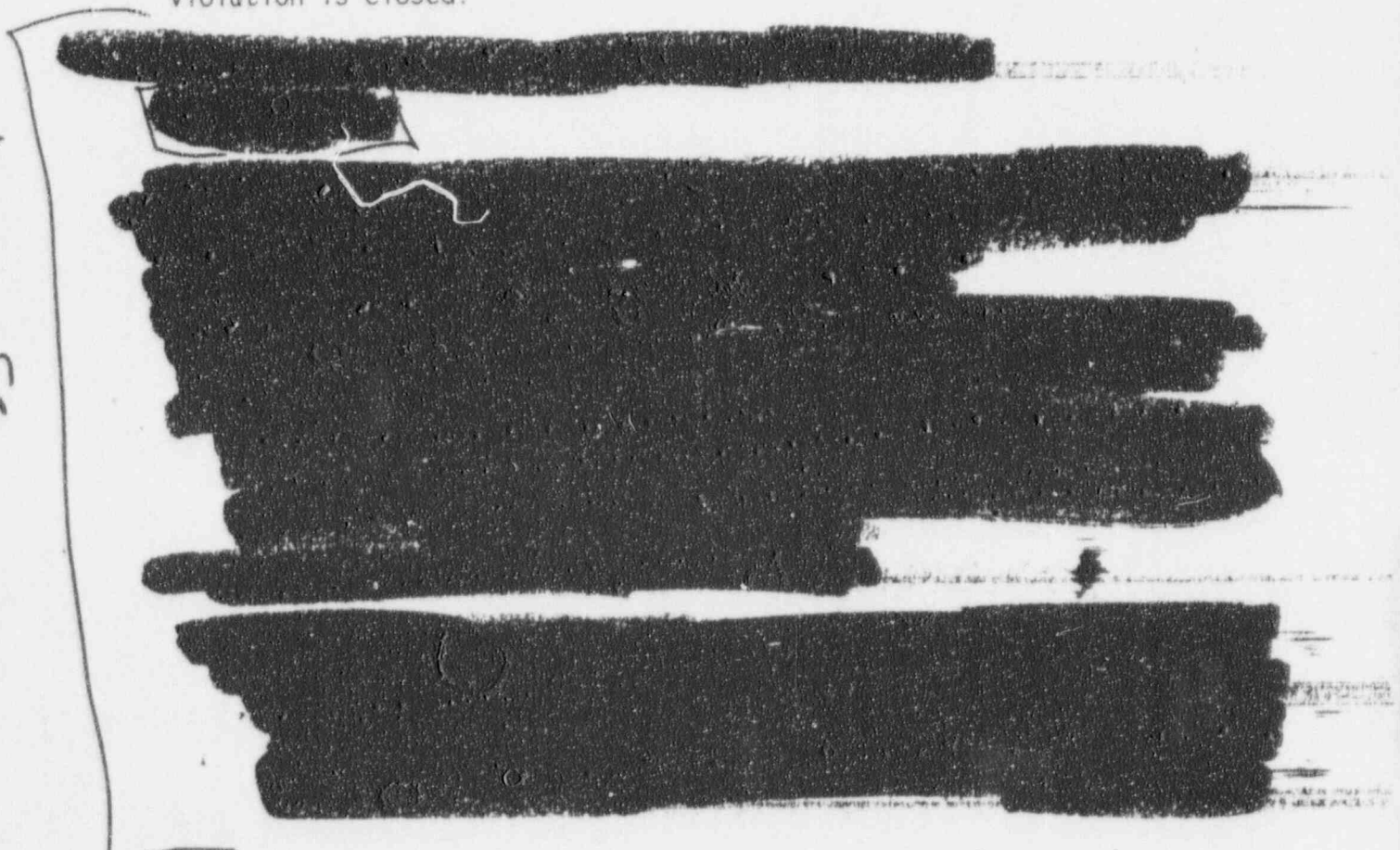
The inspector reviewed work order packages which documented maintenance activities on the subject valves for the subject period. NPWOs 61/5778 and 61/5785 documented work which had been performed on valve HCV 25-4, which had failed to operate properly during stroke testing. Work was performed on September 8 through 10, 1995. Work performed under these NPWOs included verifying proper valve/actuator alignment, removal of the actuator and bonnet, and repacking the valve.

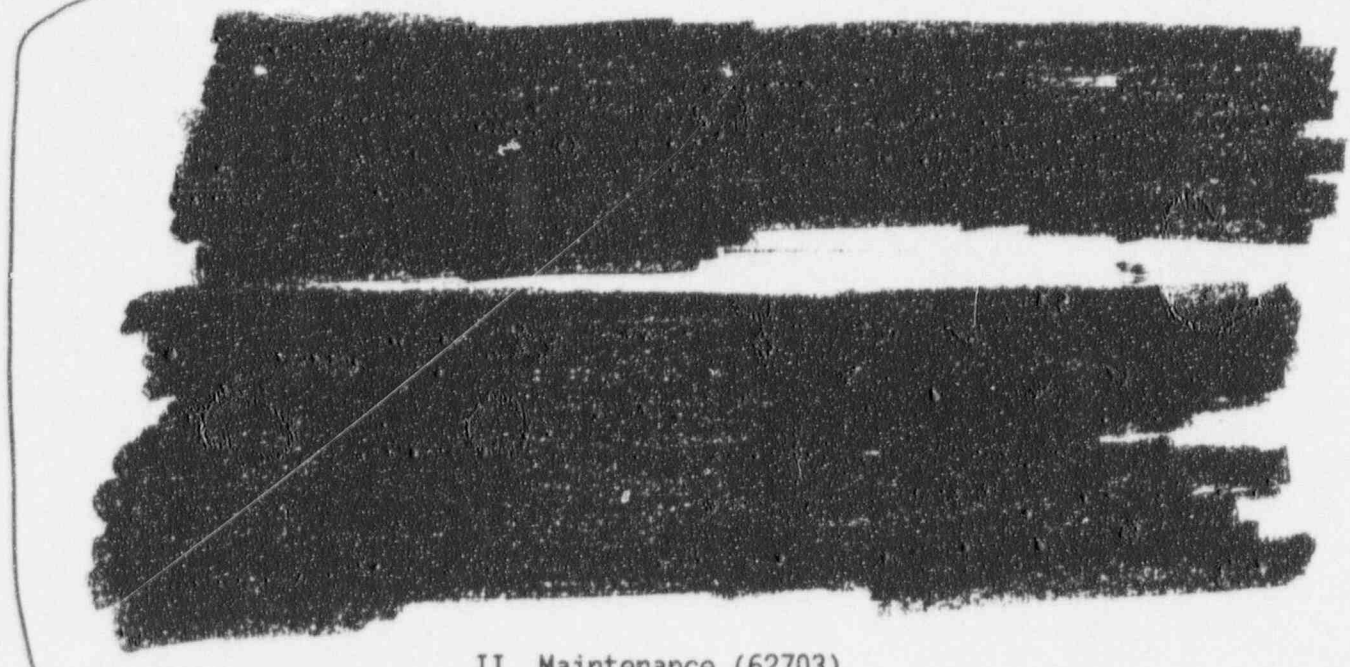
NPWO,61/5721 documented work performed on HCV 25-1, removing the valve's actuator and bonnet to inspect for blockage. This work occurred on September 1 through 5, 1995, and included the removal of approximately 1.5

pounds of debris from the valve's inlet and outlet.

All NPWO packages appeared appropriately documented and included completed procedures for the activities performed. All NPWOs included QI 11-PR/PSL-2 retest forms which required satisfactory stroke tests as post-maintenance tests. In all cases, the forms were annotated to indicate that stroke time testing was not required, as the valves were not in the licensee's IST program. The inspector verified that the valves were not included in the licensee's ASME Section XI IST program. All retests were performed satisfactorily.

The inspector reviewed the balance of the licensee's corrective actions for this event, which included briefing operations personnel on the goal of error-free operation, increased log reviews, and the adoption of a verbatim compliance policy with respect to procedures. While subsequent NRC inspections indicated that personnel errors involving logkeeping and procedural compliance continue to present a significant challenge to the licensee, the inspector concluded that the licensee's proposed corrective actions were appropriate to the subject violation and that they were executed per the commitments specified in the response to the NOV. This violation is closed.





II. Maintenance (62703)

M1 Conduct of Maintenance (62703)

M1.1 General Comments

The inspectors observed maintenance activities on systems and components to determine if the activities were conducted in accordance with regulatory requirements, approved procedures, and appropriate industrial codes and standards. The inspectors also reviewed the selected procedures and verified that corrective maintenance activities for safety-related systems and components were being conducted in a manner which resulted in reliable safe operation of the plant and plant equipment. In order to ensure that the maintenance was performed effectively, the inspectors verified the following specific elements: applicable tools were properly calibrated, correct parts and tools were used, supervision was adequate, and approved procedures/instructions were used.

M1.2 Field Observations

M1.2.1 Unit 1 Emergency Diesel Generator 1A Test and Surveillance

Prior to diesel generator test and surveillance, the inspectors observed that a diesel generator engineer and a technician walked down the radiators to check erosion/corrosion problems. Several photos were taken for evidence to show the management about severe problems on the radiators. Per the engineer, these radiators were installed just about three years ago and has corrosion problems due

to the salty environment. The licensee already plans to replace them during the coming outage. The photos would be used to confirm the severe condition and speed the process.

There were two diesel engines connecting to a common diesel generator in the middle to produce electricity. This type of diesel arrangement is called tandem. One engine contains 12 cylinders and the other contains 16 cylinders.

The procedure used for test and surveillance was Operating Procedure 1-2200050A, Rev 24, "1A Emergency Diesel Generator Periodic Test and General Operation Instructions." The inspectors observed activities related to the testing such as checking diesel mounted fuel tank level, diesel oil storage tank level, the operability of 1A fuel oil transfer pump, blowing down all four air receivers, engine and governor oil levels, engine running at 900 RPM, 4200 volts, 3400 KW of power, local alarms and annunciators in the control room, engine oil temperature and pressure, the full speed of 900 RPM at least one hour, etc. The inspectors noticed a small amount of oil leak around several cylinder covers. The engineer stated that the small amount of oil leak was normal.

The inspectors considered that the diesel generator engineer and testing operator were knowledgeable and skillful in handling the test and performing the maintenance. The diesel started as expected and ran smoothly in a good condition.

M1.2.2 Unit 2 Waste Gas Compressor Maintenance

The inspectors observed head inspection and assembly on Unit 2 Waste Gas Compressor. The seal was leaking and was replaced. The procedure used was 2-MMP-06.01, Rev 1, "Waste Gas Disassembly, Repair, and Reassembly." The compressor and parts were inspected for damage, cuts, nicks, scratches, degradation, cracks, etc. No defects were found. The parts were cleaned using Isopropyl Alcohol. All O-rings were replaced with new O-rings and the sizes of new O-rings matched the sizes of the old O-rings.

The head assembly included the installation of the support head, lower head, three layers of diaphragms, the cap screws to secure the diaphragms with the torque to six in.-lbs, the upper head, O-rings attached to all heads, and the head assembly bolts with torque to 300 ft.-lbs. The inspectors especially observed the craftsmen torque the head assembly bolts to 300 ft.-lbs in a torque sequence marked on top of the upper head because the right bolt torque sequence would distribute the torque pressure and prevent damage to the bolts and heads. The inspectors also verified the torque

wrenches to be within the calibration dates.

M1.2.3 Unit 2 CTCS Recirculating Pump 2B1 Mechanical Seal Replacement

The Condenser Tube Cleaning Systems are new systems and were installed a couple of months ago to circulate and clean intake cooling water through the condenser tubes. The recirculating pumps have leaked since the installation. The inspectors observed the replacement of the Chesterton 442 Mechanical Seal. The old seal was inspected by the licensee's engineer for damage, wear, degradation, etc. No damage was found. However, the seal was found to have wear slightly due to the grit. There was no procedure for this task. The craftsmen followed the instructions attached to the kit for the removal and installation of the seals.

During the review of the copy of the Work Order in the field, the inspectors found that the craftsmen did not sign and date on page 2 of the Work Order, which requires the craftsmen to verify that they were working on the correct unit and components prior to physically starting work. The inspectors questioned the craftsmen as to why they did not sign and date on the page 2 of the Work Order as required. They replied that the master copy (or control copy) of the Work Order was brought to the field, signed, and returned to the office prior to physically starting work. The copy of the Work Order in the field was not required to be signed since the master copy was already signed. Later, the supervisor said that the craftsmen went to the field for the clearance and came back to the office to sign the master copy which meant that they verified the correct unit and components prior to physically starting work. The inspectors questioned what the effective time spans for the clearance document were. The supervisor said "as long as you want." The problem is that the craftsmen may not go back the field immediately to physically start work due to other problems. It may be delayed a couple of days or months due to the change of the procedure, condition, environment, or emergency. Therefore, signing in the master copy after the clearance check could not verify that the act was prior to physically starting work. The copy in the field was still required to be signed and dated prior to physically starting work. The management agreed to reinforce the requirement to sign the work copy in the field. The inspectors considered this problem as a weakness.

M1.2.4 Torque Wrench Calibration

The inspectors observed the torque wrench calibration practice in order to see if they complied with the procedure. The procedure used was General Maintenance Procedure M-0004, Rev 18, "Calibration

of Mechanical Maintenance Measuring and Testing Equipment." The torque wrench tester was Model TBT-600. Prior to the torque wrench calibration, the tester itself was required to be calibrated using the same procedure.

The inspectors witnessed the retest of several torque wrenches which indicated all of them to be within the acceptable range of + or - 4 percent of torque values. Each torque wrench was checked at 20 percent, 40 percent, 60 percent, 80 percent, and 100 percent of its capacity. The torque wrench operator tested wrenches and compared the test values against the tables in the attachments to the procedure. The tables lists the acceptable ranges for each torque values. The inspectors randomly selected several torque values from the tables, checked the figures of the range values, and found them to be acceptable.

M1.2.5 Replacement of V23113

Replacement of Valve No. V23113 on Unit 2 was observed. This is the 4 inch isolation valve for the Steam Generator Closed Blowdown to the Heat Exchanger 2A-1 Inlet. Work was conducted in accordance with Master Work Order Task No. 95-028027-1A. The inspector observed welding preparations and fitup. In addition, the inspectors verified that work was performed in accordance with written instructions, proper revisions of procedures were used, welder certification, welding procedure parameters and weld filler material controls and certifications were satisfactory.

M1.2.6 Welding Supporting Control Room Air Conditioner Replacement

Welding activities for ACC-3B were observed. This is the Unit 1 air cooled condensing unit for the control room ventilation system. Work was conducted in accordance with Work Order Task No. 96-0065401. Welder certification, welding procedure parameters, and weld filler material controls and certifications were verified satisfactory.

M1.2.7 Observation of Liquid Penetrant Testing

Liquid penetrant examination activities were observed for a new pipe/valve assembly on the Unit 2 Steam Generator Closed Blowdown system. Work was conducted in accordance with Work Order Task No. 96003894 and Traveler Nos. 96-373, 4, 5, and 6. Examination of welds No. 2001, 2002, 2003 and 2004 for valves No. V23139 and V23140 were observed. The inspector verified that the examinations were conducted in accordance with approved procedure No. PT-1, Method 1, Technique sheet 9.5, Rev. 5. Welding filler materials, welder

certification and welding procedure parameters were also verified.

M1.2.8 Charging Pump Packing Replacement

Portions of maintenance activities involving the replacement of packing for Unit 2 Charging Pump No. PP2B were observed. This work was performed in accordance with Master Work Order Task No. 96006925-01 and General Maintenance Procedure No. 2-M-0041, Revision 29. The inspectors verified that work was conducted in accordance with the approved procedure, craftsmen were knowledgeable of the work process, and the proper revision of the work procedure had been verified.

M1.2.9 V23139B Corrective Maintenance

Corrective maintenance for Unit 2 Steam Generator Closed Blowdown system Valve No. V23139B was observed. This is a 3/4 inch root valve for the 2B1 heat exchanger which had developed a steam leak in the valve's bonnet to body connection. Master Work Order Task No. 96003894-01 and General Maintenance Procedure No. M-0043 was used to performed this maintenance activity. However, corrective maintenance was ineffective due to valve's state of deterioration. A determination was subsequently made to replace the valve.

M1.2.10 Waterbox Maintenance

Portions of the tube cleaning activities in the 1A2 Inlet Waterbox on the Unit 1 Condenser (1A) was observed. This work was conducted in accordance with Master Work Order Task No. 9600612101.

M1.2 Reactive inspection to follow up on licensee actions to address equipment problems identified during Unit 1 shutdown/trip on February 22, 1996.

M1.2.1 Rod Control System Problems

(a) CEA #20 dropped rod

I&C performed troubleshooting on CEA #20 per PWO 63/4997. The inspector reviewed the work package and interviewed the I&C System Supervisor present at the time to determine how the licensee approached rod control troubleshooting overall, and specifically, how this failure was diagnosed and corrected.

Tech Manual 8770-6947, Section 6.2, "EVALUATION OF IMPROPER CEDM OPERATION," stated that "the first step in locating the malfunction is to obtain a Visicorder trace of the coil currents." Included in this section were lists of common

indications of malfunctions and their causes. The I&C System Supervisor, prior to obtaining a Visicorder current trace, verified that the power transformer was operating properly and checked the 3-phase input to the power switch. At this point, he found that the 15 amp "A" and "B" phase fuses were blown. The blown fuses were replaced and the leads from the Load Transfer power switch substituted for the Upper Gripper power switch. The circuit was reenergized causing the surge suppressor resistor and diode to fail. A subsequent evaluation determined that the "A" phase Upper Gripper power switch SCR had failed in the short, current conducting mode.

After reviewing the work package, the inspector questioned the I&C System Supervisor as to whether there was a troubleshooting procedure available and/or if he had referred to the Tech manual which specifically identified for #17 Observed Condition "Dropped CEA" under Cause, "Failed SCR circuit(s) in the upper gripper power switch." The I&C System Supervisor stated that rod control troubleshooting is performed by obtaining a Visicorder trace and evaluating circuit response based on expert knowledge of the system to identify faults. In this particular instance, the Tech manual was not reviewed prior to troubleshooting and there is no I&C troubleshooting procedure for the rod control system.

(b) CEA #47 dropped rod during Unit 1 restart

I&C performed troubleshooting on CEA #47 per PWO 63/5014. Resistance checks determined a 31K Ohm reading on the Upper Gripper coil/wiring. A containment entry and check of the power cable to CEA #47 found the quick disconnect adapter was approximately eight turns loose. The I&C System Supervisor checked the remaining 60 adapters and found about five more approximately 1/16 turn loose. A second resistance reading measured approximately 8.9 Ohms which was within specifications. The inspector noted that the PWO package did not fully document the as-found condition of the adapters.

M1.2.2 Steam Bypass Control System (SBCS) Valve Problems

(a) PCV-8801 Erratic Operation

The SBCS is used at low power. Normally, PCV-8801, which is rated for five percent steam flow, modulated to control secondary pressure and temperature. The other SBCS valves (PCV-8802 through PCV-8805 are rated for 10 percent steam flow and quick-open on a reactor trip) remained closed during low

power operation. During the Unit 1 shutdown/trip on February 22, the SBCS was being used to dump steam to the condenser. The control room operators noted that SBCS valve PCV-8801 was not modulating properly. The valve controller was placed in manual by operators. The modulation problem was investigated by I&C personnel who backed out the adjusting screw on the booster relay for the valve until the booster was no longer involved in operation of the valve. The booster relay was adjusted under WO 96002418. This corrected the erratic operation. The valve controller was returned to automatic operation and no other problems were experienced.

The inspectors reviewed WO 96002418 and noted that the WO also verified that the booster relay adjusting screw was backed all the way out on PCV-8802, PCV-8803, and PCV-8805. The inspectors reviewed the two previous post trip packages for Unit 1, including the operator logs for the shutdowns and restarts and found no indication of previous erratic SBCS valve operation.

(b) PCV-8802 Failure

PCV-8802 failed to stroke during testing following the reactor trip. This test was performed to verify operation after the instrument air system was checked during followup to the problems identified (discussed below) for PCV-8804. Troubleshooting revealed that the seal around the manual operator stem and the diaphragm cover was leaking by so that there was not enough air pressure on the diaphragm to stroke the valve. The seal was replaced by I&C personnel and the valve stroked satisfactorily.

The inspectors examined the failed seal, reviewed the work order package and concluded that this failure was unique and unrelated to the problems identified for PCV-8801 and PCV-8804. The inspectors questioned whether this valve would have actuated if called upon.

(c) PCV-8804 Output Pressure Signal

While checking the other Unit 1 SBCS valves for problems similar to that found for PCV-8801, I&C personnel found that PCV-8804 had a closed input air signal to the positioner but indicated a pressure increase on the output air signal line to the valve actuator. I&C personnel removed the positioner to determine the cause of the increased output signal and noted the following:

- I&C found a black powdery substance in the tubing connection after removing the positioner. This substance was also found to a much lesser degree in valves PCV-8802, PCV-8803, and PCV-8805. PCV-8801 had not yet been examined. Finding the black powdery substance caused the licensee to perform a check of the instrument air system.

- An attempt to calibrate the positioner on the bench was unsuccessful due to excessive wear on an internal spool valve. The wear appeared to be from normal in service usage. The positioner was disassembled and the licensee found the black powdery substance and a ferrous and rubber-like material inside the positioner. However, laboratory analysis was not possible due to the small quantity (less than 1 gram) of the substance that was available. The licensee indicated during discussions that they believed the source of the rubber-like material and the black powdery substance was the actuator diaphragm. This was based on a microscopic comparison of a sample of the diaphragm with the substance collected from the positioner.

- The licensee concluded that these conditions would not cause a failure and believed that PCV-8804 would have opened upon demand. This was later confirmed when a similar output demand condition (discussed below) was found on a Unit 2 SBCS valve.

The inspectors examined the material collected from the Unit 1 SBCS valves, reviewed the chemistry reports for the monthly routine sampling performed on the IA system, reviewed several annual particulate reports and concluded that the IA system was not the source of the black powdery substance or the ferrous and rubber-like material.

The inspectors questioned the licensee as to whether the Unit 2 SBCS valves had been examined for conditions similar to those found in PCV-8804. The licensee indicated that the Unit 2 valves had not been examined because they believed that, since all the SBCS actuators and positioners had been replaced (under PCM 047-295, Steam Bypass Control System Actuator Modification) during the Unit 2 refueling outage in the fall of 1995, there was no need to perform this examination.

The inspectors reviewed the PCM package, completed work implementing documents, performed field inspections, and

verified that the actuators and positioners for the Unit 2 SBCS valves had been replaced. During the field verification, the inspectors observed that the Unit 2 PCV-8803 output demand signal read 85 psig, which was similar to Unit 1 PCV-8804 condition.

The licensee initiated STAR 960359 to evaluate the condition for Unit 2 valve PCV-8803. The evaluation concluded that a build up of positioner output pressure while the valve was in standby had no effect on valve operation. The licensee verified this conclusion by isolating PCV-8803 and capturing as-found positioner settings and valve movement, inspecting the internal positioner filters for debris, and performing a calibration check on the positioner. PCV-8803 was stroked on February 28. All pressures and strokes were normal and no movement of the valve was produced. The filters internal to the positioner were inspected and found to be clean. The licensee concluded that the cause of the positive output pressure from the positioner while the valve was in standby was an indication of leakage of the spool valve inside the positioner. Spool valve leakage could be caused by failure of the spool valve to seat or miscalibration of the spool valve signal. Spool miscalibration may be caused by calibration drift or a very small original setting discrepancy. The licensee indicated that a review of the vendor recommended steam bypass valve actuator and positioner PM guidance was in progress for both units and the results of the review would be documented in In-House Event Report No. 96-020.

The inspectors concluded that the licensee's investigation into the SBCS valve problems lacked thoroughness in that the extent of condition did not include examining the Unit 2 SBCS valves for similar conditions. Also, not all of the vendor PM guidance for the positioner was incorporated into the licensee's PM program for the SBCS valves, and these PMs had not been performed.

(d) SBCS Flow Capability

During further review of the SBCS valves, the inspectors noted that the licensee had initiated STAR 960348 for Unit 1 and STAR 951419 for Unit 2. These STARs were written to identify that the modifications to the SBCS valves may not allow the steam bypass flow capacity for the SBCS that was specified in the UFSAR. The STARs indicated that the modifications resulted in a reduction of the SBCS's ability to accommodate load rejection from up to 45 percent of full steam flow as

specified in the UFSAR to up to 39 percent of full steam flow, as indicated in licensee calculation PSL-2FSM-95-015, Revisions 0 and 1. The licensee concluded that no potential operability concern existed in any mode of plant operation. This conclusion was based on the SBCS not being required for plant safety (UFSAR Section 7.7) and there was no credit taken in any Chapter 15 Accident Analyses for the steam dump and bypass system. The steam dump and bypass valves were classified as non-seismic and non nuclear safety related. The UFSAR stated that if the bypass valves failed to open on command, the atmospheric dump valves provided a means for controlled cooldown of the RCS and the main steam safety valves provided the safety related over pressure protection for the steam generators.

The inspectors reviewed UFSAR Sections 7.7, 10.4.4, 15; STARs 960348 and 951419; and calculation PSL-2FSM-95-015, Rev 0 and Rev 1; and concluded that the licensee's operability evaluations were satisfactory and adequate technical justification was provided.

M1.2.3 Main Feedwater Regulating Valve (MFRV) Failure

(a) FCV-9011, which is the 1A MFRV, failed to properly respond and control S/G water level during shutdown. This resulted in the licensee having to trip the reactor from approximately 26 percent power. FCV-9011 operated erratically due to a leaking air line between the lockup regulator and the actuator upper air chamber. The air leak was discovered to be a failure of the IA copper tubing at the swaged fitting. The failure occurred within the ferrule which created the swaged joint. The failure caused excessive air leakage from the actuator which resulted in unstable control of the valve and an increase in the 1A S/G water level. The inspectors reviewed the licensee's actions to resolve the failure of FCV-9011 and noted that the licensee's investigation lacked thoroughness in the following areas:

- The post trip position of this valve was not verified in that the licensee did not determine if the valve had locked up (fail-as-is) as designed on a loss of IA, or if the valve had closed as designed on a turbine trip.

- The laboratory report did not discuss the condition of the non-failed joints, nor was the laboratory made aware that additional mechanical stress had been applied to the failed air line prior to analysis.

- The cause for the MFRV air supply regulator responding slowly during PMT after the IA line tubing replacement was not identified. The air regulator was replaced and the valve operated properly. The licensee concluded that the sluggish response of the air regulator was not a contributing factor to FCV-9011 unstable response.

(b) Backup IA Supply Removed From Service

During further review of the MFRV problem, the inspectors noted that the backup IA supply to the 1A MFRV had been removed from service. Discussions with licensee personnel revealed that the backup IA supply had been removed from service for several years. However, Annunciator E-41, "FW REG VLV BACK-UP AIR SUPPLY PRESS LOW," alarm and Off-Normal Procedure ONOP 1-0030131 had not been revised to reflect the current configuration of the system. The inspectors questioned licensee personnel as to whether the backup air supply had been removed from service under the licensee's equipment abandonment process. Licensee personnel indicated that the backup IA supply had not been formally abandoned, but a PCM was being prepared to address abandonment of the equipment. The inspectors noted that a clearance to isolate the MFRVs from the backup IA supply was not issued until February 24.

The inspectors concluded that the system configuration did not contribute to the MFRV failure. However, not revising the annunciator or the ONOP were considered to be a weakness.

(c) MFRV Air Supply Regulator Failure

During stroking of the 1A MFRV following IA line replacement, the "FW REG VLV SUPPLY AIR PRESS LOW" alarm was received in the control room. The licensee replaced the degraded air regulator and successfully stroked the valve with no IA alarms. The inspectors examined the replacement regulator in the field and noted that the regulator setting was approximately 100 psig. The inspectors questioned this setting since the manufacturer's label on the regulator established the service range as 35-100 psig. During their follow up to this question, the licensee discovered inconsistencies in the documents specifying the pressure at the regulator. The licensee changed the pressure setting at the regulator and indicated that the various documents were being reviewed to correct the inconsistencies.

M3 Maintenance Procedures and Documentation

M3.1 Review of LLRT Records

E4.7C [redacted]

The inspector reviewed maintenance records relating to the LLRT of the Unit 2 Equipment Hatch following the most recent refueling outage to ensure that records were appropriately documented and stored. The subject test was conducted in accordance with OP 2-1300051, Rev 13, "~~Local~~ Leak Rate Test," Data Sheet 3, "Seals." The inspector found the data sheet archived and retrievable in the vault, with results for the test in question of 260 SCCM at 42 psig following closure of the equipment hatch.

The inspector noted that no acceptance criteria for seal leakage was identified on the data sheets in question. This was discussed with the cognizant test engineer, who stated that the data obtained was combined with other LLRT data and compared to a total leakage acceptance criteria. The inspector reviewed the entire archived package for the performance of the test in question and could not identify where any summation of LLRT data had occurred. The cognizant engineer was also unable to identify where the combined LLRT leakage data was archived. As a result, a new leakage summary was prepared (using the data which had been archived), reviewed and submitted for archival. When totaled, all containment leakage summaries were well within acceptable limits.

M3.2 Maintenance Procedures

E4.7C [redacted]

During the work activities described in paragraph M3.1, above, the inspectors noted that the craftsmen would go verify that the procedure they were using was the appropriate revision in accordance with the requirements of paragraph 4.5 in Procedure No. QI 6-PR/PSL-1 (Document Control). One occasion when the inspectors accompanied the craftsmen to perform this verification the craftsmen found that revision 14 of Procedure No. M-0043 which the planner had furnished in the maintenance package was not the current revision when compared with the maintenance control copy in the North Service Building. Further review by the inspectors also revealed that the procedures index was not being updated when new procedure revisions were received as the cover sheet of the index stated. The inspectors also questioned whether the control procedures were available to backshifts since the doors of the room had locks on them.

The inspectors discussed the issue with appropriate management personnel

regarding the above procedure control concerns. The discussion revealed that document control only considered the procedure index correct on the date indicated on the index cover sheet. In accordance with procedure this is a dated once every three months when control copies of the procedures are audited against an up to date index. The inspector was also informed that the craft know to verify their procedures against the control copies of the documents verses the index, since the index is a memorandum and by procedure does not supersede the requirements of a control document. Based on observations of craftsmen audited this inspection, procedures in the maintenance package are verified against the control copy of the procedure. In addition, the craftsmen audited followed the document control procedure and used the correct revision of the procedure in each case. The apparent discrepancy of the planner issuing the incorrect revision of General Maintenance Procedure No. M-0043 resulted because the planner had entries to made in the procedure and on the date he made these entries he had verified revision as the correct revision on that date. This, therefore, was not a discrepancy but one of the reasons the craftsmen are required to verify the procedure before use.

As a result of above findings and questions raised by the inspector, two STAR Action Reports were written (Nos. 960456 & 7) to evaluated the effectiveness of document control. Management's attention focused on corrective actions in response to these reports and during the week the inspector was on site (March 25-29) the following corrective measures were established.

- All maintenance groups now will use only one new centralized library in the North Service Building. This library has an attendant manning it and updating control procedures 10 Hrs. a day. The room where the library is located has also had the locks removed from the doors in order that no backshift personnel are excluded from using the facility.

- The document index cover sheet has been revised to insure that this uncontrolled document is not used for procedure status except on the date indicated on the cover sheet.

- When planners now verify procedure revisions during the planning stage they will double stamp the procedure and only sign one verification blocks. This will require the user to also verify the procedure.

- An up-to-date procedure index will be established on all on-line computers by approximately August 1996. When this enhancement is fully implemented the index will supersede all documents for establishing procedure status. All plant personnel will have access to the index at that time.

The inspectors considered the steps taken or in the process of being taken by the licensee to be substantial improvements in document control. All actions observed during the above corrective maintenance were also found to be satisfactory.

M5 Maintenance Staff Training and Qualification

M5.1 Maintenance Department Reorganization

[redacted]

The licensee recently implemented a major reorganization in its maintenance organization. Major aspects of the action involved breaking the organization down into functional areas and the creation of rotating shift supervisors who rotate through shifts with the NPSs and who are tasked with coordinating the overall maintenance efforts for their shifts. The stated purpose of the reorganization was to provide better support to Operations by providing single points of contact and accountability and to provide the segregation of responsibilities necessary to free field personnel from administrative duties to allow focus on the plant. Reporting to the Maintenance Manager under the new organization are:

- 5 Rotating Shift Supervisors
- A Valve and Welding Supervisor
- A Rotating Equipment Supervisor
- A Stationary Equipment Supervisor
- A Unit 1 Electrical Supervisor
- A Unit 2 Electrical Supervisor
- An Outage Projects Supervisor
- A Maintenance Budget Supervisor
- An Instrumentation and Control Supervisor
- A Project and Maintenance Support Supervisor
- A Maintenance Programs Supervisor

The inspector performed a random sampling of maintenance supervisor qualifications for the positions listed above and for supervisory personnel reporting to those above. TS 6.3.1 (both units) stated that the unit staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1 - 1978. The ANSI/ANS standard required that supervisors (as defined by the standard) possess a High School Diploma or equivalent and that they have at least 4 years of experience in the discipline they supervise. QI 1-PR/PSL-1, "Site Organization," required that records be kept indicating that these qualifications were met. The inspector reviewed the licensee's records for 10 randomly selected supervisors and found that the records were complete, included a verification that the ANSI/ANS requirements were met, and included records of past experience and of all completed FPL

training. No deficiencies were identified.

M7 Quality Assurance in Maintenance Activities

M7.1 Unit 1 CEDM coil resistance readings

Following maintenance on CEA #47, the inspector reviewed Tech Manual 8770-6947 guidance for CEDM periodic maintenance and, more specifically, the coil resistance parameters. Tech manual sections 6.1.2.1 and 6.1.2.2 recommended:

- Each refueling, "The upper gripper coil resistance should be measured and recorded. Deviations of greater than .5 ohms should be investigated" and,

- Periodic maintenance, "Check the resistance of each coil and its resistance to ground every third year. The resistance of the coil should be within 10 percent of the initial resistance per Table 3, and the resistance to ground at 500V should be a minimum of 10^6 ohms."

The licensee calculated the mean and standard deviation for each of the coils and identified all coils that fall outside +/- 2 X S.D. Insulation resistance for all five coils and the cable is measured at one time and must be > 1 megohm @ 500V which is consistent with the Tech Manual specification.

The inspector reviewed PWO 63/8002 which measured CEDM coil stack resistances prior to the last Unit 1 outage in 1994. Seven coils were identified as outside of 2 X S.D., four of which were annotated as System 80 coils. The inspector reviewed the attached raw data tables and identified four additional coil resistance readings outside of 2 X S.D.

The inspector also reviewed PCM 133-191 completed May 1993. This PCM upgraded the CEDM power cables and installed the quick disconnect adapters. These adapters were installed hand tight with the caveat "Do not use excessive force or any hand tools." PWO 63/0046 which supported this modification provided QI 3-PR/PSL-1, Rev 29, "Acceptance Criteria", item #11 Attachment 4 "PCM Testing Document." This was "The resistance readings for the CEDM lift coil, load transfer coil, pulldown coil, lower gripper and upper gripper coil are within the range of Figure 20 of Ref. Man. 3.2 +/- 1 ohm." In the "Detailed Procedure", item #12:

- item 12.1

  At the Coil Power Programming Cabinets, measure and record all five coil resistances for shutdown and regulating CEDMs. (12.1)

- attachment 012FYP8002, FRG approved #93-132

  1) At CPP Cabinets measure and record UG coil resistance for each startup and regulating CEDM. Ensure one lead of field cable is lifted prior to measuring and is relanded prior to continuing to next. Use a meter with resistance resolution of 0.01 ohms.

  2) Record CEDM temperature if possible, using temperature probe.

  3) Calculate the mean and standard deviation for resistance and identify all CEDM coils that fall outside the mean plus or minus 2 X standard deviation.

- item 12.3

  Calculate the mean and standard deviation for resistance and identify all CEDM coils that fall outside the mean +/- (2 * standard deviation).

The inspector noted that item 12.3 had two calculated means and standard deviations; Lift coil mean 3.514, standard deviation 0.120 (handwritten) and (Unidentified) Mean 7.501, standard deviation 0.229.

The inspector calculated the mean and standard deviation for each of the stack coils consistent with the methodology used in PWO 63/8002:

COIL	MEAN	S.D.	2 X S.D.
LIFT	3.52	0.12	0.23
UPPER GRIPPER	7.46	0.27	0.55
LOWER GRIPPER	7.49	0.28	0.57
PULLDOWN	7.53	0.15	0.29
LOAD TRANSFER	7.53	0.18	0.36

The inspector identified 13 CEDMs whose coil resistance readings were outside the allowable range of the calculated means +/- 2 X S.D:

	Coil	Allowable Range	Outside	
•	Lift	3.29 - 3.75	#2	3.8
			#17	3.1
•	Upper Gripper	6.91 - 8.01	#43	6.2

			#49	8.1
			#52	6.2
•	Lower Gripper	6.92 - 8.06	#43	6.1
			#52	6.2
•	Pulldown	7.24 - 7.82	#24	8.1
			#48	7.9
•	Load Transfer	7.17 - 7.89	#9	8.1
			#22	7.1
			#28	7.0
			#49	8.2

Using the values calculated in the PWO 63/0046 and assuming that the unidentified mean and standard deviation applies to all but the Lift coils:

	Coil	Allowable Range	Outside	
•	Lift	3.27 - 3.75	#2	3.8
			#17	3.1
	All Others	7.04 - 7.96		
•	Upper Gripper		#43	6.2
			#49	8.1
			#52	6.2
•	Lower Gripper		#43	6.1
			#52	6.2
•	Pulldown		#24	8.1
•	Load Transfer		#9	8.1
			#28	7.0
			#49	8.2

This method should have identified the above 11 CEDMs resistance readings as outside the acceptance criteria.

Using the "Acceptance Criteria" item 11 and assuming a CEDM temperature of 80° F, the allowable ranges including lead resistance, are:

	Coil	Allowable Range	Outside
•	Lift	2.34 - 4.34	None
•	Upper Gripper	5.98 - 7.98	#49 (UG & LT)
	Lower Gripper		#24 (PD)
	Pulldown		#9 (LT)
	Load Transfer		

Item 13 "Test Documentation" contains the statement by the Journeyman that "All values are acceptable." PWO 63/0046 under Task Description step 3 is a signed verification stating "Verify the resistance readings are within the acceptance criteria of the QI 3-PR/PSL-1." The inspector concluded that the acceptance criteria provided in this PCM was confusing and not entirely met.

I&C issued a STAR to Engineering in October 1995 requesting acceptance criteria for coil resistances. Engineering is working with vendor and has made a commitment to close this STAR 30 days prior to the scheduled Unit 1 refueling outage.

The safety significance of this finding with respect to coil condition was minimal in that the vendor who has reviewed coil resistance data (Unit 2) has not provided the licensee any limiting values and the Tech Manual may have been misapplied with respect to appropriate acceptance criteria for this PCM. However, the inspector was concerned about the apparent failure to apply and recognize that the acceptance criteria was not met. This failure to assure that test results had been satisfied, as identified above, is identified as a violation (VIO 335/96-04-04, "Failure to Adequately Evaluate Unit 1 CEDM Coil Resistance Test Results").

M7.2 FRG review of Unit 1 CEA #1

On March 7 the inspector attended the FRG meeting which reviewed PWO 63/5102. This PWO contained a detailed procedure for installation and removal of test equipment in troubleshooting CEA #1 prior to performing MTC testing (see paragraph 03a of this report).

As part of the FRG review process, the originator of the PWO verbally described what this PWO would accomplish and responded to questions by FRG members. At the completion of the review process the FRG secretary prepared the minutes for signoff.

The inspector received a copy of the PWO for review and noted the requirement under the completed Technical Review signoff that "Vendor tech manuals, drawings, documents/NPWO instructions used as procedures must be reviewed and approved by the FRG prior to use." Steps 3 and 12 of the PWO referred to performing steps in Tech Manual 8770-6947.

AP 0010432, Rev 88, "Nuclear Plant Work Orders," instruction 8.4.3.D.4 states, in part, "In the case where a controlled vendor technical manual is to be used to provide step-by-step instructions, the specific sections (e.g., paragraphs and steps) shall be invoked in the work description or the technical manual or portions thereof attached to the NPWO, as necessary." This requirement is part of the "level of usage" philosophy

adopted in September 1995 thus eliminating FRG review of complete vendor technical manuals. After the inspector questioned whether this requirement had been satisfied, a copy of the referenced tech manual steps was attached to this NPWO prior to FRG approval.

The inspector concluded that FRG had addressed the relevant safety issues adequately but had not reviewed the NPWO in sufficient detail to identify the above deficiency.

M8 Miscellaneous Maintenance Issues (62703, 92904, 92902, 92700)

M8.1 (Closed) Unresolved Item 335/96-01-01

URI 96-01-01 documented a condition identified by the NRC on February 15, in which workers in a posted contaminated area were observed not adhering to the applicable RWP requirements for anti-contamination clothing. Observed conditions included an unbuttoned lab coat, wearing cloth gloves only (no rubber gloves), and failing to wear gloves.

The inspector reviewed the issue with the licensee and determined the following:

- An RWP (96-119) was properly prepared for the work in question
- Radiological requirements for the job in question were appropriately established and met the minimum requirements for a contaminated area specified in HP-50, "Protective Clothing Requirements"
- The area in question was not contaminated at the time the condition was observed

The licensee initiated a Radiological Deficiency Report to document the issue and determined, through interviews that the observed conditions resulted from workers forgetting requirements in the course of attempting to correct a deficiency which had placed the unit in a 72 hour TS AS. This appeared to be complicated by the fact that the workers reported knowing that the area was radiologically clean, based upon previous surveys, which contributed to a causal attitude toward the requirements of the RWP.

The licensee's corrective actions included stopping the work and counseling those involved, management reiteration of expectations for w under RWPs and a revision to ADM-08.02, "Conduct of Maintenance," wh added a verification that RWP requirements were met prior to beginnin work.

The inspector concluded that the observed conditions constituted a violation of the licensee's procedures, which required adherence to RWP requirements. However, the licensee's corrective actions were adequate

and the event was of minimal safety significance. The inspector concluded th finding constitutes a violation of minor significance and is being treated as a NCV, consistent with Section IV of the NRC Enforcement Policy (NCV-96-04-05, "Improper Health Physics Practices").

M8.2 (Closed) LER 335/94-010, "Inadvertent B Train Engineered Safeguards Features Actuation Signal (ESFAS) due to a deficient Instrument and Control Test Procedure."

The inspector reviewed the subject LER and the corrective actions specified in the LER. The inspector verified that the corrective actions identified in the LER were completed, and that procedures were revised to include the corrective actions when applicable. The inspector concluded that the corrective actions were satisfactory. Based on the implementation of the corrective actions, the LER is closed.

M8.3 (Closed) LER 335/94-009-1, "Inadvertent Safety Injection Actuation Signal/Containment Isolation Signal Due To Failed Pressure Transmitters."

The inspector reviewed the corrective actions associated with the LER and found them to be acceptable. Documentation reviewed indicated that I & C personnel completed the replacement of five transmitters as specified in the corrective actions and plans are in place to replace other transmitters in the future. Based on the implementation of the corrections action specified, the LER is closed.

M8.4 (Closed) LER 335/94-008-0, "Inadvertent Containment Isolation Signal (CIS) Caused By Failure Of The B Instrument Invertor Concurrent With Channel D CIS in Tripped Condition."

The inspector reviewed those procedures identified in the corrective actions, and verified that specified changes had been incorporated into the procedure. Based on the completion of the specified correction action the LER is closed.

M8.5 (Open) LER 335/96-001-00, "Control Room Emergency Ventilation System Inoperable Due to Improper System Configuration."

On February 19, at approximately 2:25 a.m., the STA observed an apparent negative pressure when entering the Unit 1 control room. In the subsequent investigation it was discovered that due to maintenance activities in the Electrical Equipment Room, two ventilation boundaries were breached, i.e. inlet plenum access hatch opened on February 19, at approximately 2:20 a.m., for periodic maintenance on HVS-5B fan and the access hatch removed on HVA-3C with the inlet damper in the open position as replaced on February 18, at approximately 12:30 p.m. This inadvertently established a ventilation flow path with intake supply air

drawn from the control room and discharged to the RAB. Immediate corrective actions were taken to close the access doors for both HVA-3C and HVS-5A and HVS-5B. This restored the control room HVAC to its design basis for accident conditions capability as of 2:37 a.m.

The licensee performed an Engineering Assessment which is documented in LER 335/96-001-00 and concluded that this configuration placed the Unit 1 control room outside of its design basis. An immediate 1-hour notification (outside of design basis - event #29994) was made on February 19, pursuant to 10 CFR 50.72.

The inspector reviewed the licensee's LER, RCO logs, clearance logs, Equipment Out-Of-Service logs and concluded that the licensee's immediate corrective actions were timely and that the Engineering Assessment adequately evaluated the safety implications of this configuration. Unit 1 was placed in TS 3.0.3 at 2:20 a.m., however, the immediate corrective actions were completed within the one hour allowed. The inspector was unable to close this LER in that not all of the corrective actions have been implemented.

III. Engineering

E4.7C [redacted]

E2 Engineering Support of Facilities and Equipment (37551)

E2.1 Unit 1 Spent Fuel Pool Boroflex Nonconformance

During blackness testing on the Unit 1 spent fuel pool conducted March 14 through 17, 1995, the licensee found one portion of one boroflex panel missing. Boroflex panels were added to the fuel pool in 1988 to allow the use of high density fuel racks. The panels absorb neutrons, creating storage cells which are, essentially, isolated from a neutronics perspective. Per the Unit 1 UFSAR, 9.1.2.3, the cells act to ensure that k_{eff} will remain less than .95 for a series of postulated conditions, to include the loss of all soluble boron in the pool. Soluble boron levels in the pool are to be maintained at a minimum of 1720 ppm per TS 5.6.3.

The missing section of boroflex existed at the top 15 inches of the panel separating cells AH17 and AG17. At the time of the discovery, the Reactor Engineering Supervisor discussed the issue with the inspector and stated that corrective actions were being considered. STAR 950548 was prepared to document the condition. In the interim, the affected cells were removed from consideration for storage of fuel.

Safety Evaluation JPN-PSL-SEFJ-95-023, Rev 3, "Revised Safety Evaluation for Missing Partial Boroflex Panel in PSL SFP Storage Cell 17AH." The

inspector reviewed the package, which documented the licensee's root cause effort, corrective actions and 50.59 evaluation. The licensee could not establish a root cause for the subject condition, except to conclude that it was a manufacturing defect. The conclusion that the condition was a manufacturing defect, vice degradation or shrinkage (as has been seen in the material in the past) was based on an abrupt, rather than ragged profile observed in the blackness test data. The inspector reviewed the test results in a test report prepared by the blackness testing vendor (HOLTECH International). The subject deficiency was highlighted, as were less significant instances of gaps in other panels

The licensee's evaluation then determined that the missing boroflex was an isolated occurrence based upon the following:

- The subject deficiency was the only such deficiency identified in the 154 panels for which blackness tests at St. Lucie have been performed.
- The vendor which manufactured the boraflex panels (Joseph Oat Corp.) had an approved Appendix B QA/QC program and the program was augmented by a resident FPL QC inspector during manufacturing. The program required a verification of proper sizing of each boraflex panel by both the mechanic performing the work and a QC inspector.
- FPL performed audits of vendor records after the discovery of the condition, and found adequate supporting information to conclude that inspections were performed as required.
- The deficiency was the only one of its type reported by industry in more than 2500 panels for which EPRI reported test results, including over 1700 manufactured by the subject vendor. Additionally, the subject panel was the only one to exhibit the deficiency of three panels of the same lot number in the St. Lucie Unit 1 fuel pool.

The licensee's evaluation also considered the fuel storage history of the subject cells and determined that two spent fuel assemblies had been stored adjacent to one another, separated by the subject panel, for a period of approximately three and one half months. The assemblies were verified to have the required burnup for storage in those locations and included essentially natural uranium axial blankets of 6 and 9 inch lengths, which reduced the reactivity in the area of the missing boraflex.

The inspector reviewed the applicable sections of the FSAR and found that the licensee had correctly characterized the issue with respect to the history of the affected cells. Additionally, the inspector found that the licensee's corrective action (placing the cells off-limits to fuel storage in the future) was sufficient to ensure safety in the future. The inspector reviewed AP 1-0010250, Rev 4, "Guidelines for the Use of the Unit 1 High Density Spent Fuel Racks," Preoperational Test procedure

3200090, Rev 15, "Refueling Operations," and Plant Physics Curve D.3, "Spent Fuel Map," and verified that the appropriate changes had been made to prohibit storage in the affected cells.

The inspector found that the licensee had been less than thorough in evaluating the potential scenarios which might have occurred with the condition unknown to the licensee. In particular, the UFSAR, section 9.1.2.3.1.3 stated that the inadvertent placement of a fresh fuel assembly in the region of the pool affected by the deficiency had the potential to exceed the limiting reactivity should there be a concurrent loss of soluble boron and that, in such a case, the presence of 500 ppm boron would ensure that the infinite multiplication factor would not exceed the design basis reactivity for that region of the pool. The licensee's evaluation did not address whether a misplaced fresh fuel assembly, in the absence of soluble boron, would have exceeded design basis limits. Similarly, the licensee's evaluation did not consider what the worst case scenario would be, should a similar defect exist in another area of the pool; instead choosing to describe the subject defect as isolated and non-recurring.

The inspector attended a FRG meeting on March 12, which discussed the subject issue. The inspector verified that a quorum was present. The FRG chairman acted properly to keep the focus of the discussion on safety and the entire FRG directed pertinent questions toward the presenter. Of particular interest to the inspector, the FRG questioned how the SE could attempt to credit the vendor's QA program as insurance against other failed panels when such an obvious deficiency escaped the 100% verification process. The preparer could not answer how the deficiency passed through the process, but stated that the extensive program which was in place, complimented by an FPL employee on-site at the vendor location assuring implementation of the program, combined with the lack of other deficient panel data provided the necessary assurance that the problem was not generic.

In conclusion, the inspector found the licensee's evaluation of the subject condition to be satisfactory and the 50.59 evaluation to be appropriately supported. The inspector found the FRG review process aggressive in its review of the issue and appropriately focused on safety.

IV. Plant Support (83750)

R1 Radiological Protection and Chemistry (RP&C) Controls (83750)

R1.1 External and Internal Exposure Controls

This program area was reviewed to evaluate the adequacy of licensee RP controls for internal and external radiation hazards and to verify

individual radiation doses did not exceed the dose limits described in Subpart C, of 10 CFR Part 20.

Selected elements of the licensee's personnel exposure control program were reviewed. Based on direct observation, review of records and discussions with licensee personnel the inspectors noted the following:

- Reviewed RWP's provided adequate RP instructions and controls;
- Personnel monitoring equipment was utilized appropriately;
- Locked high radiation areas were properly posted and secured; and
- Process and engineering controls to limit exposures to airborne radioactivity were considered and utilized when possible.

The licensee reported the following maximum doses (Rems) for individuals in calendar year 1995 and 1996 to date:

Year	TEDE	Skin	Extremity	Lens-Eye
1995	2.263	2.452	2.452	2.263
1996	0.254	0.258	0.258	0.254
Part 20 Limits:				
	5.000	50.000	50.000	15.000
Adm. Limits:				
Site	2.500	25.000	25.000	7.500
Total	4.500	45.000	45.000	13.500
1996 data through February 26, 1996.				

In 1995, the highest individual CDE dose assigned was 287 mrem and the highest CEDE dose assigned was 33 mrem. No individual internal exposures had been identified at the time of the inspection for 1996. All external and internal exposures were well within the regulatory limits.

The licensee has applied for NVLAP certification of its electronic dosimeter program. The licensee has completed performance testing in categories II, IV, and VI.b. and passed in categories IV and VI.b. The licensee did not plan to re-test in category II, an accident category since the licensee did not plan to use the electronic dosimeters as the primary dosimeter for emergency response. The licensee had already received its on site review and expected certification of the electronic

dosimetry program in 1996. The licensee has been conducting parallel testing of TLDs and electronic dosimeters for approximately two years. The licensee expects to keep the TLD as the dose of record, at this time. The licensee planned to continue using TLDs for special monitoring conditions such as high beta dose component fields or neutron fields. The on-going work in obtaining accreditation of the FPL electronic dosimetry program was identified as a good example of the health physics program technical capabilities.

Through review of licensee procedures and reported dose information, the inspector concluded the licensee was implementing adequate RP controls and monitoring individual occupational radiation exposures in accordance with the requirements and that all individual doses reported were within 10 CFR Part 20 limits.

No violations or deviations were identified.

R3 RP&C Procedures and Documentation (83750)

R3.1 Control of Radioactive Materials and Contamination, Surveys and Monitoring

E47C [redacted]

This area was reviewed to evaluate the licensee's control of radioactive and contaminated material.

St. Lucie TS 6.8.1 required written procedures be established, implemented and maintained covering the activities recommended in Appendix A of RG 1.33, Rev 2, dated February 1978. RG 1.33, Appendix A, 1978, required written procedures for contamination control.

The inspector reviewed the licensee's procedures for the control of tools within the licensee's RCA. St Lucie HPP- 41, Rev 1, "Movement of Material and Equipment," dated September 29, 1994, described the licensee's procedures for positive control of materials and equipment located in and leaving the RCA. Section 7.5 of HPP-41 addressed the use of tools and equipment in the RCA. Step 7.5.2 stated "Paint contaminated tools and equipment designated for use in the RCA with purple paint." Step 7.5.3 stated, in part, "Unless otherwise authorized, use only those tools that meet the following criteria for fixed and removable radioactivity:

- Beta-Gamma < 10 mrem/hr Fixed and

  < 1,000 dpm/100 cm^2 Removable."

During a tour of the licensee's RCA the inspector noticed maintenance workers working on some equipment in the Hot Tool Room. The inspector

inquired about the workers activities and learned the equipment was not from any contaminated system. While there, the inspector observed several maintenance workers searching for various tools and observed one worker returning tools to the storage cabinets. The worker returning tools reported the tools had not been used. The inspector noted the Hot Tool Room was a self-serve facility and that there appeared to be little control of materials or tools entering or leaving the room. Many workers left the tool room without the tools they had been looking for and the inspector noted some of the tool bins were empty.

The inspector made independent radiation and contamination surveys of the items stored there. During the survey the inspector found numerous tools that were not painted with purple paint and 2 tools exceeding the contamination levels for such tools. One tool having approximately 14 mrem/hr beta gamma exceed the fixed beta gamma contamination limit of 10 mrem/hr and another set of jacking bolts having contamination levels of approximately 1,500 dpm/100 cm^2 exceeded the removable contamination limit of 1,000 dpm/100 cm^2. The inspector identified the tools to a health physics technician and they were promptly removed from the Hot Tool Room for decontamination. The inspector stated that failure to paint tools utilized in the RCA with purple paint and failure to control tools having radiation levels in excess of licensee procedure limits appeared to be violations of licensee procedure requirements. The inspector reported the finding constitutes a violation of minor significance and is being treated as a NCV, consistent with Section IV of the NRC Enforcement Policy.

NCV 50-335,389/96-04-06: Violation of TS 6.8.1 requirements for failure to follow contamination control procedures for the control and use of contaminated tools in the RCA.

In order to provide better control of these tools, licensee representatives reported that there would be a worker assigned to the Hot Tool Room for half a day on day shifts and the tool room would be locked at all other times.

The inspector also requested and observed surveys of selected tools in the licensee's Clean Tool Room. No contaminated tools were found during those surveys.

The inspector toured the yard and individual buildings in the RCA and noted that there appeared to be more contaminated material stored within the RCA than the inspector had observed at the site on previous RP inspections. The inspector determined that some of the additional material was material that had not been decontaminated following the 1995 outages. The problems with the Hot Tool Room and the amount of contaminated material accumulating around the site appeared to be the related to the significant cuts in the numbers of utility workers on site

during and following the most recent outages. The inspector reported to licensee management that continued attention was needed to reduce the amount of radioactive material and contaminated material the licensee had stored in yard and warehouses. Licensee representatives reported temporary personnel would be hired during the next few months to reduce the backlog of contaminated material.

Housekeeping in the Auxiliary Buildings was generally good. However process areas such as the decontamination facility and equipment storage areas such as the one near the Unit 1 personnel access hatch were cluttered and untidy. No uncontrolled containers of radioactive material or contamination were identified.

At the time of the inspection the licensee reported there were only 250 ft^2 of contaminated area in the licensee's decontamination plan, which included 106,063 ft^2. The plan excluded the Containment Buildings and certain process areas such as the decontamination facility. The 250 ft^2 was the lowest level obtained by the licensee in recent years.

The inspector reviewed documentation of selected PCEs and annual PCE trends. The inspector noted that the licensee had approximately 83 PCEs in 1995 which exceed the goal of 50 PCEs. The number of outage days in 1995, approximately 170, was the primary reason the licensee had exceeded this goal. The licensee actually had fewer PCEs in 1995 than in 1994. The licensee had 95 PCEs in 1994 with approximately 104 outage days. The licensee documented PCEs at a threshold of 100 cpm above background, measured with a thin window GM detector. The inspector noted the licensee surveyed the walkways in the Auxiliary Buildings daily with large swipes which helped in reducing the number of PCE occurring in clean areas. No concerns with PCEs were identified during the inspection.

The inspector observed several empty drums in the RCA and inquired about the licensee's procedures for releasing empty drums having once contained hazardous material or used oil. The inspector learned that drums containing a hazardous material and radioactive contamination were not released and were stored within the RCA. Fifty-five gallon drums of hazardous material free of radioactive contamination and exiting the RCA were stored on a special pad on the secondary side of the facility. Used oil leaving the RCA which could have been exposed to radioactive contamination was sampled and analyzed for uncontrolled release.

The inspector determined that used oil from the site was collected in a holding tank for offsite processing. The inspector also learned that the licensee had processors for separating water from oil which were located on the secondary side of the facility in the Turbine Buildings. The separated oil from an oil and water mixture was transferred to the oil holding tank and the separated water was released to the yard drainage

system which emptied into evaporation/percolation ponds located within the protected area.

The inspector noted that the east pond was posted with signs displaying a radiation symbol and the words: "Restricted Area -Keepout" and "Radioactive Materials Area." The inspector determined that the east pond had received some contaminated water from a spill in 1977. The inspector learned that in 1992 the licensee had sampled and evaluated the soil from the pond berm and bottom. At that time, detectable radioactive contamination was observed at various depths of 1-6 feet with the activity decreasing with depth. The most significant level of contamination detected was in the first three feet of sediment below the pond with radioactive concentrations of 1.5E-6 micro-Ci/g of Cs-137 and 2.4 E-6 micro-Ci/g of Co-60. Licensee representatives reported that the water was currently free of measurable contamination. The inspector observed several species of fowl utilizing the pond during the inspection. No concerns with the removal of drums from the primary to secondary side of the facility were identified.

One NCV and no deviations were identified.

R5 Staff Training and Qualification in RP&C (83750)

R5.1 Training

This area was reviewed to verify that site health physics technicians were receiving continuing training.

Through interviews with licensee personnel, review of licensee training documents and training records the inspector determined that the licensee was providing continuing training for health physics technicians. The licensee provided approximately 37 hours of continuing training for health physics technicians in 1995 and expected to provide approximately that amount in 1996. However, the licensee had not developed a schedule for proposed training. The inspector noted the 1995 training provided was appropriate for continuing health physics technician training. The inspector determined the technicians generally found the quality of the training good and useful for their responsibilities.

No violations or deviations were identified.

R6 RP&C Organization and Administration (83750)

R6.1 Occupation Radiation Exposure Control Program Changes

Changes in the RP program, since the last inspection, were reviewed to assess their impact on the effective implementation of the RP program.

The inspection focused on changes in organization, personnel, facilities, equipment, programs, and procedures. The previous RP inspection was conducted during the period of May 30 through June 2, 1995. With the exception of organizational changes described below the licensee had not made any significant changes in the RP program.

The site health physics department lost several positions in down-sizing activities in February 1996. The number of site senior health physics technicians was reduced from 32 to 30 and 2 health physics supervisor positions were also eliminated. The most significant change in numbers of staff reductions was the decline in decontamination workers from 22 to 12.

The responsibilities held by the Special Project Material Condition Supervisor and Instrumentation Supervisor were temporarily transferred to the ALARA Supervisor and the Radioactive Waste Supervisor respectively. The inspector did not identify any concerns with the licensee's changes in organization structure or in the qualifications of personnel receiving new program responsibilities. While the loss of the two supervisors reduced collective staff expertise it did not appear that the changes would adversely affect the licensee's programs for control of radiation exposures and radioactive materials.

No concerns were identified with the reductions in the number of health physics technicians. The decontamination workers reductions did appear to have a negative impact on the quantity of contaminated material the licensee had stored around the facility (Paragraph R3.1). However, no violations of regulatory requirements concerning the control of radioactive material were identified during the inspection.

The organization chain of command structure from the site Health Physics Supervisor to the Operations Manager to the Plant General Manager had not changed. However, recent changes in personnel were made for the Operations Manager and the Plant General Manager positions.

There were also decreases in the number of vendor personnel supporting site health physics activities in 1995. The number of senior health physics technicians decreased from 69 in 1994 to 51 in 1995. Other decreases from 1994 levels to those in 1995 included: junior health physics technicians from 41 to 18; dosimetry technicians from 16 to 13; and decontamination personnel from 53 to 44. Additional decreases in the numbers of vendor support personnel during outages were not expected in 1996. However, the licensee planned to bring in the personnel as needed and did not plan to use the personnel throughout the entire outage.

No violations or deviations were identified.

R7 Quality Assurance in RP&C Activities (83750)

R7.1 Audits

Audits of RP activities were reviewed to determine the adequacy of the licensee's identification and corrective action programs for deficiencies or weaknesses related to the control of radiation or radioactive material.

The inspector reviewed the licensee's 1995 and 1996 audits of RP program activities. Reviews of RP activities during this period were limited to several performance monitoring activities which the licensee referred to as PMONs. Five PMONs were conducted in the RP area in 1995 and two were on-going during the inspection for 1996. The inspector also reviewed the checklist and auditor notes for each of the 1995 PMONs. One finding requiring corrective actions was identified in the five PMONs and the inspector verified it's corrective actions were proceeding.

The inspector determined that the licensee was reviewing the RP program and tracking audit findings for correction. No concerns with the licensee's audit program, findings or corrective actions were identified.

No violations or deviations were identified.

R8 Miscellaneous RP&C Issues (83750)

R8.1 Maintaining Occupational Exposures ALARA

This program area was reviewed to determine the status and effectiveness of ALARA program initiatives in reducing collective dose for the site. Areas reviewed included site annual and outage goals and objectives, and the collective dose results.

A summary of recent collective dose and goals for the site is shown below.

Collective Personnel Exposures (Person-Rem)						
	Annual Dose			Outage Dose		
	Actual	Goal	Title	Actual	Goal	Days
1993	460	477	U2-SNO	71	-	77
			U1-RFO	387	444	61
			U1-SNO	55	-	12
1994	505	600	U2-RFO	168	187	71
			U1-RFO	290	361	33

1995	412	283	U1-SNO	18	-	8
			U1-SNO	41	-	80
			U2-RFO	311	172	83
1996	7	356	U1-RFO	-	-	-

Notes:

The 1996 dose information was measured with electronic dosimeters and was current through February 26.

The 1996 U1-RFO outage goals had not been issued.

Unplanned outages, maintenance activities and re-work were the primary reasons the licensee exceeded the 1995 annual collective dose goal of 283 person-rem by approximately 129 person-rem. This was basically a maintenance and operations problem which significantly and adversely impacted the station ALARA program. The duration of the U2 RFO was expected to be 53 days and actually lasted approximately 83 days due to expanded work scope and rework. The licensee also had an extended outage on U1 of approximately 80 days. Even with the increased work load, the 1995 annual collective dose was the lowest since 1992 when the licensee had 245 person-rem.

The site collective dose goal for 1996 had just been approved by plant management. The ALARA staff had identified four possible site collective dose goals for management consideration. The goals considered such factors as industry averages and historical performance. Upper management selected the most challenging one at 356 person-rem.

The licensee had just started a new ALARA Man-Rem Budget program similar to one utilized at Turkey Point. At the time of the inspection the plan had just been approved and little use of the system had been made. The plan assigned a dose budget for each department and the departments were required to complete assigned responsibilities without exceeding their allotted dose budget. An element of the plan permitted departments to borrow dose from one another as needed. The licensee expects the implementation of the process to result in increased involvement of the St. Lucie staff in dose reduction solutions.

The licensee completed a permanent modification on U2 Containment Building in 1995 which provided air conditioning to the building during outages. The licensee planned to make the same modification on U1 during the 1996 RFO scheduled for Spring 1996. The licensee had found that air

conditioning had generally increased worker efficiency and safety and had resulted in fewer PCEs from leaching protective clothing. The air conditioning modification was an example of licensee management's support for personnel safety, RP and ALARA programs.

The inspector also learned the licensee had started preliminary preparations for a U1 SG replacement project scheduled for January in 1998.

Based on direct observation, discussion and review of records the inspector concluded the licensee was utilizing ALARA techniques and making progress in reducing collective doses for the staff. However, the recent failure to meet 1995 annual collective dose goal indicated additional attention to reduce collective doses during outages was needed.

No violations or deviations were identified.

P4 Staff Knowledge and Performance in EP (71750)

On January 22, at approximately 7:45 p.m., Unit 2 began a downpower from 100 percent to 90 percent in preparation for turbine valve testing. During the downpower, I&C was changing a FC (Field Contact) - 250 power supply for annunciator housing #1, in the annunciator logic cabinet. At approximately 8:20 p.m., annunciator panels H (Reactor Coolant System), J (Reactor Coolant Pumps), K (CEAs), L (Reactor Protection System), M (CVCS) and N (Waste Management) on RTGB 203, 204 and 205 went into alarm and remained locked in. The licensee entered ONOP 2-0030137, "Partial or Complete Loss of Annunciators," and stabilized power at approximately 97 percent.

At approximately 8:35 p.m., I&C identified and replaced the redundant FC-250 power supply fuse in the annunciator logic housing #1 which had blown. The locked in annunciator alarms cleared and at approximately 8:40 p.m. appeared to be operating properly. The ONOP was then exited.

The inspector reviewed IHE #96-009, the work package generated, and the EPIP 3100022E, "Classification of Emergencies."

The inspector reviewed the PWO work package with the I&C Supervisor. The Journeyman observed an electrical arc between the electrical lead and the terminal where the lead was being relanded prior to the blown fuse indication for the redundant power supply. The I&C Manager said this should not have occurred.

The inspector also reviewed the Engineering Justification for PCM 045-293M which was approved November 23, 1993 and subsequently implemented. This

PCM provided an individual field contact power supply for each of the four annunciator logic housings which would result in a partial loss of approximately 25 percent of the annunciators rather than complete loss due to a single power supply failure. This MEP was classified as Non-Safety Related.

EPIP Event/Class 8.B, "Loss of Alarms/Communication/Monitoring" provides the following criteria for an Unusual Event:

Significant loss of effluent monitoring capability, communications, indication and alarm panels, etc., which impairs ability to perform accident or emergency assessment.

3. Unplanned loss of most or all Safety System annunciators for greater than 15 minutes."

If the initiating condition is met for entry into the EAL and even though the condition has cleared, the NPS is required to make an emergency declaration per EPIP steps 4.3 and 8.2. In this particular instance, although the RTGB 203, 204 and 205 annunciators were lost for greater than 15 minutes, the NPS concluded that redundant alarms on RTGB 206, ERDADS, RPS, ESFAS, LPM and the PACB were adequate so as not to impair accident or emergency assessment.

In IHE 96-009, under paragraph VIII, Reportability Evaluation:

> "It was determined that most safety system annunciators remained operable during this anomaly so no emergency classification needed to be made."
>
> "For the majority of annunciators affected, redundant alarms on RTGB 206, ERDADS, RPS, ESFAS, LPM and the PACB were available to alert operators to abnormal conditions."

The inspector recognized that a reportability determination involved applying engineering judgment. However, entry into an EAL requires identification and evaluation of which safety system annunciators remained operable. In this regard, the inspector requested that the licensee identify all safety system annunciators and for those annunciators that were lost, i.e. windows H, J, K, L, M and N, the redundant alarms which are referred to above. In a subsequent discussion with lead STA, the licensee position was that any single failure of an annunciator power supply would not constitute an entry condition for an emergency classification.

The inspector concluded that while the emergency classification and reportability determination was correct for this occurrence, it may be nonconservative in other cases, particularly RTGB 206.

V. Management Meetings and Other Areas

X1 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with the UFSAR commitments. During an approximate two month time period all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, procedures, and/or parameters.

While performing the inspections which are discussed in this report the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and parameters.

Minor deficiencies were noted with respect to the Containment Spray System walkdowns performed during this period. They were as follows:

- V07223 was to be locked closed per UFSAR paragraph 6.2.6.4. The valve was found to be administratively controlled as locked closed per the appropriate administrative procedure, however, the procedure was not annotated to refer to the UFSAR commitment, as is normally done per the licensee's programs.
- UFSAR Table 6.2-22 shows Unit 1 NaOH concentration as 30-32 w/o. TS 3.6.2.2.a specified 28.5-30.5 w/o.
- Unit 2 UFSAR Table 7.3-4 lists the EDGs as being started on a CSAS. This feature was removed via PCM during the most recent Unit 2 outage.

These issues were forwarded to the licensee for resolution.

X2 Exit Meeting Summary

A pre-exit meeting was held with the licensee on February 29, 1996, to discuss the results of inspections relating to the February 22 trip of Unit 1 and associated maintenance issues. Dissenting comments were not received from the licensee.

The inspection scope and findings for the occupational radiation exposure inspection were summarized in a pre-exit meeting with the licensee held on March 1, 1996. Upper plant management, e.g., Plant General Manager, Site Vice President, Operations Manager, did not attend the exit meeting. The

inspector asked that the inspection findings and the inspector's comments be conveyed to upper plant management. The inspector described the areas inspected and discussed in detail the inspection results. The inspector reported to licensee management that continued attention was needed to reduce the amount of radioactive material and contaminated material the licensee had stored in yard and warehouses. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

A pre-exit meeting was held with the licensee on March 8, 1996 to discuss a visiting inspectors observations of maintenance activities. Dissenting comments were not received from the licensee.

A pre-exit interview was held with the licensee on March 28, 1996 to discuss observations of control room activities. Dissenting comments from the licensee's management are described in paragraph 04.3, above.

A pre-exit meeting was held with the licensee on March 29, 1996, to discuss aspects of maintenance observations made during the preceding week. Dissenting comments were not received from the licensee.

The scope and results of this integrated inspection report were discussed with the licensee in an exit meeting conducted on April 3, 1996. Dissenting comments were not received.

X3 Pre-Decisional Enforcement Conference Summary

A Pre-Decisional Enforcement Conference was held with the licensee on March 8, 1996, at NRC Region II to discuss potential enforcement resulting from IR 50-335,389/96-03, which discussed an overdilution event which occurred on Unit 1.

PREDECISIONAL
DRAFT INFORMATION - NOT FOR DISTRIBUTION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Bladow, W., Site Quality Manager
Bohlke, W., Site Vice President
Buchanan, H., Health Physics Supervisor
Burton, C., Site Services Manager
Dawson, R., Business Manager
Denver, D., Site Engineering Manager
Fincher, P., Training Manager
Frechette, R., Chemistry Supervisor
Fulford, P., Operations Support and Testing Supervisor
Heffelfinger, K., Protection Services Supervisor
Holt, J., Information Services Supervisor
Kreinberg, T., Nuclear Material Management Superintendent
Marchese, J., Maintenance Manager
Olson, R., Instrument and Control Maintenance Supervisor
O'Farrell, C., Reactor Engineering Supervisor
Pell, C., Outage Manager
Wood, C., System and Component Engineering Manager
Sager, D., Vice President, Nuclear Assurance
Scarola, J., St. Lucie Plant General Manager
Weinkam, E., Licensing Manager
West, J., Operations Manager
Marple, C., Operations Supervisor
White, W., Security Supervisor

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

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operations
IP 71715:	Sustained Control Room and Plant Observation
IP 71750:	Plant Support Activities
IP 83750:	Occupational Exposure
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-335/96-04-01	VIO	"Failures to Follow Procedures Lead to Unit 1 Containment PIG Inoperability"
50-335/96-04-02	VIO	"Failure to Make Required Log Entries"
50-335/96-04-03	VIO	"Failure to Follow Procedures While Placing EDG Fuel Oil Tank on Recirculation"
50-335/96-04-04	VIO	"Failure to Adequately Evaluate Unit 1 CEDM Coil Resistance Test Results"

Closed

50-335/95-015-03	VIO	"Failure to Follow Procedures and Document Abnormal Valve Position"
50-335/96-01-01	URI	"Improper Health Physics Practices"
50-335/96-04-05	NCV	"Improper Health Physics Practices"
50-335/94-010-00	LER	"Inadvertent B Train Engineered Safeguards Features Actuation Signal (ESFAS) due to a Deficient Instrument and Control Test Procedure"
50-335/94-009-01	LER	"LER 335/94-009-1, Inadvertent Safety Injection Actuation Signal/Containment Isolation Signal Due To Failed Pressure Transmitters"
50-335/94-008-00	LER	"Inadvertent Containment Isolation Signal (CIS) Caused By Failure Of The B Instrument Invertor Concurrent With Channel D CIS in Tripped Condition"
50-335,389/96-04-06	NCV	"Failure to follow contamination control

		procedures for tools utilized in the licensee's RCA"

Discussed

335/96-001-00	LER	"Control Room Emergency Ventilation System Inoperable Due to Improper System Configuration"

LIST OF ACRONYMS USED

ADM	Administrative Procedure
AEOD	Analysis and Evaluation of Operational Data, Office for (NRC)
ALARA	As Low as Reasonably Achievable (radiation exposure)
ANPS	Assistant Nuclear Plant Supervisor
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOV	Air Operated Valve
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ATTN	Attention
BOP	Balance of Plant
cc	Cubic Centimeter
CDE	Committed Dose Equivalent
CEA	Control Element Assembly
CEDE	Committed Effective Dose Equivalent
CEDM	Control Element Drive Mechanism
CFR	Code of Federal Regulations
Ci	Curies
CIS	Containment Isolation System
cm	Centimeter
CMI	CEA Motion Inhibit
cpm	Counts Per Minute
CPP	Coil Power Programming
CTCS	Condenser Tube Cleaning System
CVCS	Chemical & Volume Control System
CWD	Control Wiring Diagram
CWP	CEA Withdrawal Prohibit
DFO	Diesel Fuel Oil
DFOST	Deisel Fuel Oil Storage Tank
dpm	Disintegration Per Minute
DPR	Demonstration Power Reactor (A type of operating license)
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Item
EFPD	Effective Full Power Days
EOP	Emergency Operating Procedure
EP	Engineering Package
EPIP	Emergency Plan Implementing Procedure
ERDADS	Emergency Response Data Acquisition Display System
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
F	Fahrenheit
FC	Field Contact

FCV	Flow Control Valve
FLCEA	Full Length Control Element Assembly
FPL	The Florida Power & Light Company
FR	Federal Regulation
FRG	Facility Review Group
GM	Geiger-Muller
HCV	Hydraulic Control Valve
HP	Health Physics
HPP	Health Physics Procedure
HVAC	Heating Ventilation and Air Conditioning
HVS	Heating and Ventilating Supply (fan, system, etc.)
HX	Heat Exchanger
I&C	Instrumentation and Control
IA	Instrument Air
IHE	In-House-Event Report
IP	Inspection Procedure
IR	[NRC] Inspection Report
ISOL	Isolated
IST	InService Testing (program)
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LIS	Level Indicating Switch
LLRT	Local Leak Rate Test
LPM	Loose Parts Monitor
LS	Level Switch
LT	Level Transmitter
MEP	Minor Engineering Package
MFRV	Main Feedwater Regulating Valves
MFW	Main Feed Water
MMP	Mechanical Maintenance Procedure
MOV	Motor Operated Valve
mrem	millirem
MSIV	Main Steam Isolation Valve
MTC	Moderator Temperature Coefficient
MV	Motorized Valve
NaOH	Sodium Hydroxide
NCV	NonCited Violation (of NRC requirements)
No.	Number
NOUE	Notice of Unusual Event
NOV	Notice of Violation
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NVLAP	National Voluntary Laboratory Accreditation Program
ohm	Unit of Electrical Resistance
OHM	Occupational Health Management

ONOP	Off Normal Operating Procedure
OOS	Out Of Service
OP	Operating Procedure
PACB	Plant Auxiliary Control Board
PCE	Personnel Contamination Event
PCM	Plant Change/Modification
PCV	Pressure Control Valve
PDIL	Power Dependent Insertion Limits
PDR	NRC Public Document Room
PIG	Particulate-Iodine-Noble Gas Monitor
PIS	Pressure Indicator/Switch
PM	Preventive Maintenance
PMON	Performance Monitoring
PMT	Post Maintenance Test
ppm	Part(s) per Million
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
PWO	Plant Work Order
QI	Quality Instruction
RAB	Reactor Auxiliary Building
RCA	Radiation Control Area
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
Rev	Revision
RFO	Refueling Outage
RG	[NRC] Regulatory Guide
RII	Region II - Atlanta, Georgia (NRC)
RO	Reactor [licensed] Operator
RP	Radiation Protection
RPS	Reactor Protection System
RTGB	Reactor Turbine Generator Board
RWP	Radiation Work Permit
SALP	Systematic Assessment of Licensee Performance
SBCS	Steam Bypass Control System
SCCM	Standard Cubic Centimeters per Minute
SCE	Systems and Component Engineering
SCFM	Standard Cubic Foot/Feet Per Minute
SCR	Silicon Controlled Rectifier
S.D.	Standard Deviation
SDC	Shut Down Cooling
SE	Safety Evaluation
SG	Steam Generator
SGWL	Steam Generator Water Level
SNO	Short Notice Outage
SNOW	Short Notice Outage Work