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

Report Nos.: 50-335/92-07 and 50-389/92-07

Licensee: Florida Power & Light Company
9250 West Flagler Street
Miami, FL 33102

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

Facility Name: St. Lucie 1 and 2

Inspection Conducted: March 24 - May 2, 1992

Inspectors: S. A. Elrod, Senior Resident Inspector — May 26, 1992 Date Signed

M. A. Scott, Resident Inspector — May 26, 1992 Date Signed

R. P. Schin, Project Engineer — 5/26/92 Date Signed

Approved by: K. D. Landis, Section Chief, Division of Reactor Projects — 5/29/92 Date Signed

SUMMARY

Scope:

This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, evaluation of licensee self-assessment capability, fire protection review, preparation for refueling, review of special reports, review of nonroutine events, followup of previous inspection findings, and followup of regional requests.

Results:

This inspection found Unit 1 continuing to operate in a routine manner with an obvious regard for safety. Unit 2 set a light water reactor world record of 502 days of continuous power operation when it shut down on April 20 for refueling. During the Unit 2 shutdown, the turbine did not trip automatically or manually when the operators tripped the reactor. Immediate operator response was excellent and subsequent root cause investigation has been vigorous. Preparation and control of entry into reduced inventory were quite well controlled. A number of surveillances and maintenance activities were well performed. One procedure violation was observed while setting steam generator safety valves. Another violation of technical specifications was observed involving isolation of a containment pressure transmitter sensing line.

Within the areas inspected, the following violations were identified:

VIO 389/92-07-03, Isolation of Containment Pressure Sensing Line Without Placing Effected Instrumentation Channels in Trip or Bypass as Required, paragraph 2a.

VIO 389/92-07-04, Failure to Follow Procedure for Setting Steam Generator Safety Valves, paragraph 5k.

Within the areas inspected, the following non-cited violations were identified associated with events reported by the licensee:

NCV 335/92-07-01, Fuel Handling Building Ventilation Radiation Monitor Out of Service Due to Personnel Error, paragraph 9a.

NCV 335/92-07-02, Containment Atmosphere Particulate and Gaseous Radioactivity Monitors Out of Service Due to Personnel Error, paragraph 9b.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

* D. Sager, St. Lucie Plant Vice President
* G. Boissy, Plant General Manager
  J. Barrow, Fire/Safety Coordinator
  H. Buchanan, Health Physics Supervisor
* C. Burton, Operations Manager
  R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Manager
* R. Englmeier, Nuclear Assurance Manager
  R. Frechette, Chemistry Supervisor
* J. Holt, Plant Licensing Engineer
* C. Leppla, Instrument and Control Supervisor
* L. McLaughlin, Licensing Manager
  G. Madden, Plant Licensing Engineer
  A. Menocal, Mechanical Supervisor
* T. Roberts, Site Engineering Manager
  L. Rogers, Electrical Supervisor
  N. Roos, Services Manager
  C. Scott, Outage Manager
* M. Shepherd, Operations Training Supervisor
* D. West, Technical Manager
* J. West, Operations Supervisor
  W. White, Security Supervisor
  D. Wolf, Site Engineering Supervisor
  E. Wunderlich, Reactor Engineering Supervisor

Other licensee employees contacted included engineers, technicians, operators, mechanics, security force members, and office personnel.

NRC Employees

* S. Elrod, Senior Resident Inspector, St. Lucie Site
* M. Scott, Resident Inspector, St. Lucie Site
  R. Schin, Project Engineer, Division of Reactor Projects

* Attended exit interview.

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Review of Plant Operations (71707)

Unit 1 began and ended the inspection period at power - day 131 of continuous power operation.

Unit 2 began the inspection period at power and then shut down on April 20 for a normal refueling outage. The outage was scheduled to last until June 27. Unit 2 set a light water reactor world record for continuous power operation during this just completed run of 502 days.

a. Plant Tours

The inspectors periodically conducted plant tours to verify that monitoring equipment was recording as required, equipment was properly tagged, operations personnel were aware of plant conditions, and plant housekeeping efforts were adequate. The inspectors also determined that appropriate radiation controls were properly established, critical clean areas were being controlled in accordance with procedures, excess equipment or material was stored properly, and combustible materials and debris were disposed of expeditiously. During tours, the inspectors looked for the existence of unusual fluid leaks, piping vibrations, pipe hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment, and instrument calibration dates. Some tours were conducted on backshifts. The frequency of plant tours and control room visits by site management was noted to be adequate.

The inspectors routinely conducted partial walkdowns of ESF, ECCS, and support systems. Valve, breaker, and switch lineups as well as equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system and area walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

Unit 2 CCW platform,
Unit 1 AFW trestle space,
Unit 1 mechanical penetration room, and
Unit 2 ICW pump area.

On April 29, during a tour of the Unit 2 containment, the inspectors observed an instrument sensing line penetrating the containment at penetration 58. The penetration was labeled to indicate that its function involved differential pressure between the containment and RAB. The sensing line was capped. Subsequent pressure test confirmed the sensing line to have indeed been isolated. Drawing 2998-B-231, sheet P136, Instrumentation Installation Details Unit 2, Rev 1, showed that this line served safety-related PT-07-2C, channel "C" containment pressure transmitter. This transmitter provided one of four containment pressure signals for several safety functions - reactor trip, containment isolation actuation, containment spray actuation, and safety injection actuation. When found, this sensing line and associated transmitter, one of four, was not available to perform its safety function for either the RPS or ESFAS. The pressure transmitter would behave as if the channel were in "bypass."

Three conditions contributed to the probability of this occurrence:

(1) The licensee did not ensure the sensing lines were open in conjunction with equipment calibration or at the beginning of operating cycles.

The licensee calibrated containment pressure sensing instrumentation on a refueling outage basis per TS 4.3.1.1 and associated table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements, and TS 4.3.2.1 and associated table 4.3-2, Engineered Safety Features Actuation System Instrumentation Surveillance Requirements, which was implemented in part by I&C procedure 2-1400153C, Reactor Protection System - Engineered Safeguards System Loop Instrumentation Calibration for Containment Pressure. This procedure allowed test equipment hookup near the pressure transmitter in the RAB, isolated by closing a valve between the test point and the containment sensing point. The sensing lines from the containment to the pressure transmitter were not specifically tested. At the conclusion of the 1989 refueling outage, based on an NRC concern that blockage of open-ended sensing lines could exist yet be undetected, the licensee blew down the sensing lines and verified air flow per plant work order 7826/62. The licensee did not subsequently test the lines during the 1990 refueling outage.

(2) Drawings, procedures, and labels did not clearly show the function of sensing lines and differentiate between active and spare lines.

Two of the penetrations involved had four lines in each. Three of the four lines were capped and one had an open-ended 90 degree male thread adaptor attached. The other two penetrations had one line each with the open-ended 90 degree male thread adaptor attached. One of these single lines was the one found isolated. Containment pressure instrumentation sensing tubing and fittings penetrating into the containment were described on drawing 2998-B-231, sheet P136. Neither the drawing, nor labels, nor other reasonably available information visually showed which of the multiple lines were in service and which were the spares. They all looked alike except for the end fittings threaded onto the pipes.

(3) Drawings, procedures, and labels did not clearly show the acceptable tubing and end fitting configuration of sensing lines inside containment.

Containment pressure instrumentation sensing tubing and fittings penetrating into the containment were described on drawing 2998-B-231, sheet P136. Neither the drawing, nor labels, nor other reasonably available information visually showed the acceptable tubing and end fitting configuration. The bill of material listed items that apparently would result in an

open-ended line with an exposed male tubing fitting thread at the end. In contrast, the drawing did show, outside containment in the RAB, a 3/8 inch mud dauber cap (item 70A) on the transmitter high-side reference sensing line. This device was intended to prevent blockage of the reference sensing line by foreign material such as an insect. The device also provided a finished appearance to the installation. The inspector judged that exposed tubing threads on the end of a line penetrating containment, coupled with poor labeling, would certainly invite someone to install a cap during a pre-startup inspection.

Unit 2 TS addressed this equipment in several places because the pressure transmitter served multiple safety functions:

- Unit 2 TS 3.3.2 and included Table 3.3-3 required that ESFAS instrumentation be OPERABLE for the Containment Spray function in Operational Modes 1, 2, or 3; including a minimum of three of the four channels of Containment Pressure - High-High. Action Statement 17 required that, with three of the four channels OPERABLE, the inoperable channel must be placed in the tripped condition within 48 hours. Action Statement 17 further stated that one additional channel may be bypassed for up to two hours for surveillance testing.

- Unit 2 TS 3.3.2 and included Table 3.3-3 also required that ESFAS instrumentation be OPERABLE for the Safety Injection, Containment Isolation, and Main Steam Line Isolation functions in operational Modes 1, 2, or 3; including a minimum of three of the four channels of Containment Pressure - High. Action Statement 13 required that, with three of the four channels OPERABLE, power operation may continue provided that the inoperable channel is placed in the bypassed or tripped condition within one hour. Action Statement 14 required that, with two of the four channels inoperable, power operation may continue provided that one of the inoperable channels has been bypassed and the other inoperable channel is placed in the tripped condition within one hour.

- Unit 2 TS 3.3.1 and included Table 3.3-1 required that RPS instrumentation be OPERABLE in operational Modes 1 or 2, including a minimum of three of the four channels of Containment Pressure - High. Action Statement 2.a required that, with three of the four channels OPERABLE, power operation may continue provided that the inoperable channel is placed on the tripped or bypassed condition within one hour. Action Statement 2.b required that, with two of the four channels OPERABLE, power operation may continue provided that one of the inoperable channels has been bypassed and the other inoperable channel is placed in the tripped condition within one hour.

Containment Pressure Channel C (High and High-High) was actually inoperable during the previous operating cycle from about at least December, 1990, to April 22, 1992, and possibly from April 13, 1989, when the sensing line was last blown out, because its instrument sensing line inside containment was capped, and Containment Pressure Channel C was not placed in the tripped or bypassed condition as required. During most of this time, St. Lucie Unit 2 was operated in Mode 1 or 2. Additionally, between December, 1990 and April 22, 1992, with Containment Pressure Channel C inoperable, another channel of containment pressure was placed in bypass on April 19, 1992, for three hours while the unit was operated in Mode 1 or 2. Between April 13, 1989 and April 22, 1992, with Containment Pressure Channel C inoperable, another channel of containment pressure was placed in bypass on six different occasions, for a total of approximately 97 hours, while the unit was operated in Mode 1 or 2.

This is identified as VIO 389/92-07-03, Isolation of Containment Pressure Sensing Line Without Placing Effected Instrumentation Channels in Trip or Bypass as Required.

Subsequent to discovery of the capped sensing line, the licensee has expeditiously evaluated the potential root causes and consequences of the condition. Activities included:

(1) Analysis of maintenance and operating history to:

(a) Bound the inoperability of containment pressure channel C. The Unit 2 sensing lines were blown out on 19 April, 1989 - two outages ago.

(b) Correlate other equipment outages due to maintenance or test.

(2) Engineering analysis of the potential accident consequences of this channel being inoperable. The analysis assumed the entire containment spray system was inoperable. The licensee's analysis concluded that no containment breach nor additional core damage would occur.

(3) Development of a technique to use on an operating plant to check Unit 1 and Unit 2 to ensure that the same conditions were not present elsewhere. The inspector observed these tests per NPWOs 7340/63 (Unit 1) and 7452/64 (Unit 2). The test consisted of blowing air from a hand-carried low pressure storage tank through the sensing lines from a test connection near the transmitter. The pressure gage would indicate while air was flowing but would immediately drop to zero when the tank's discharge ball valve was shut, thus showing a clear flow path. All four sensing lines for each of Unit 1 and Unit 2 were clear.

(4) Search of operating records from previous reactor plant heatups to determine if the isolated pressure sensing line could have been detected during startup. The licensee concluded that the lack of indication was reasonable based on the containment volume of about 2.5 million cubic feet and the small amount of heatup due to containment cooling in operation.

(5) Probabilistic Risk Assessment PSL-2JFR-92-004 dated May 7, 1992 and evaluating the risk input to St. Lucie Unit 2 due to the isolation of PT-07-2C. It concluded that the loss of that channel represented a 3.9E-8 per reactor year increase in CDF over having all channels operable. The frequency calculated was 1.23E-7 per reactor year. This was compared to NRC criteria listed in GL 88-20:

- It was less than the 1.0E-6 screening value;

- A St. Lucie total CDF has not been determined. Even if it were as low as 1.0E-5 per reactor year, the 1.27E-7 contribution would be less than the 5% of total CDF screening value referenced in GL 88-20.

- Even if the evaluated sequence were conservatively assumed to result in core damage and containment failure, the estimated CDF was still less than the 1.0E-6 screening value.

- Loss of the spray function did not constitute a containment bypass function.

The 1.2E-7 per reactor year sequence would not therefore be considered potentially important.

(6) Physical and procedural changes were being pursued to identify sensing lines opening into the containment or annulus and to ensure the required status would be easily understood.

- Identification tags to indicate the purpose and required condition of these sensing lines.

- Changes to procedures for surveillance and plant startup to verify that the lines are clear.

- Drawing revisions as necessary to capture the required line status and to install end covers (mud dauber screens) on the ends of the lines.

The inspector had no further questions at the time.

b. Plant Operations Review

The inspectors periodically reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs, operating orders, standing orders, jumper logs, and equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. They observed and evaluated control room staffing, control room access, and operator performance during routine operations. The inspectors conducted random off-hours inspections to assure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. Except as noted below, no deficiencies were observed.

During this inspection period, the inspectors reviewed the following tagouts (clearances):

2-3-104	2B EDG [12 cylinder diesel fan shaft repair],
2-3-35	HVE 10B Motor Replacement [routine maintenance],
2-4-9	2A HPSI pump breaker repair (see the maintenance paragraph),
2-4-24	2B1 circulating water pump out for water box cleaning, and
2-4-222	HVE 6B Heater Control Inspection.

Unit 2 commenced a shut down for refueling on April 20. Since this was the first Unit 2 shutdown in 502 days, both the licensee and inspector showed additional interest in operating staff performance and equipment reliability. The operating staff performed well during both routine evolutions and unexpected occurrences. The licensee treated the shutdown as an infrequently performed evolution per AP 0010020, Rev 1, Conduct of Infrequently Performed Tests or Evolutions at St. Lucie Plant, and focused additional management attention. Pre-evolution briefings were held by the operations supervisors and the procedures were talked through at length by the on-shift licensed operators during the shift prior to commencement. Copies of needed procedures were tabbed and conveniently placed in notebooks within arm reach of the reactor control station. The quality assurance staff also provided extensive coverage.

The licensee performed initial power reduction per OP 2-0030125, Rev 14, Turbine Shutdown - Full Load to Zero Load. Procedure adherence was excellent. Reactor plant and steam plant equipment generally worked very well, with a few exceptions. Prior to commencing shutdown, the 2A train 6.9 KV circuit breaker from the generator auxiliary transformer would not open from the control room to transfer the switchgear feed to the startup transformer. The

shutdown was delayed until the circuit breaker was returned to service in about two hours. During the power reduction, the B-train low-flow feedwater controller level input failed, so an operator manually controlled 2B SG level from the control room console.

At low power and late in core life, the licensee found that axial shape index was difficult to keep within limits using the CEA controls allowed by TS. The operators had previously decided that, if three of four pretrip alarms initiated, they would trip the reactor manually rather than continue attempting a manual shutdown. When these alarms indicated at 2:38 a.m. on April 21, the reactor operator tripped the reactor from 12 percent power and initiated standard post trip actions per 2-EOP-01, Rev 6, Standard Post Trip Actions.

Though the reactor trip itself was uneventful with reactor plant safety equipment subsequently performing as designed, the turbine trip function did not perform as designed. The turbine did not trip either automatically or manually from the control board. Operators immediately carried out compensatory actions, including shutting the main steam isolation valves, tripping the generator output circuit breaker, stopping the turbine control DEH pumps, and tripping the turbine using the local manual control at the turbine front standard. After the safety functions of 2-EOP-01 were met, the licensee initiated 2-EOP-02, Rev 5, Reactor Trip Recovery. The licensee subsequently initiated a root cause investigation and maintained Unit 2 at normal no-load temperature for over 24 hours pending initial investigation, removal of certain key components for dissection, and determination that no critical evidence would be destroyed.

The licensee started reactor cooldown on April 22 per OP 2-0030127, Rev 43, Reactor Plant Cooldown - Hot Standby to Cold Shutdown. The cooldown of about 35 degrees per hour was plotted as required using data sheets 1, 2, and 3. Unit 2 entered operational modes 4 and 5 later that day.

During the inspection period, Unit 1 entered a reduced RCS inventory condition to install SG nozzle dams. The following items were observed prior to or during this evolution:

- Containment Closure Capability - Instructions were issued to accomplish this; personnel and tools were on station.

- RCS Temperature Indication - Four normal mode 1 CETs were available for indication. Two were from train A and two from train B.

- RCS Level Indication - Independent RCS wide and narrow range level instruments which indicate in the control room were operable. An additional Tygon tube loop level in the

containment was manned during level changes and checked every two hours during static conditions.

- RCS Level Perturbations - When RCS level was altered, additional operational controls were invoked. At plant daily meetings, operations took actions to ensure that maintenance did not consider performing work that might effect RCS level or shutdown cooling.

- RCS Inventory Volume Addition Capability - Nominally one (of three) charging pumps and a HPSI pump were available for RCS addition.

- RCS Nozzle Dams - Procedural control was via MMP-01.05, Rev 0, Steam Generator Primary Side Maintenance. This required the pressurizer manway be removed prior to installation of nozzle dams, that hot leg manways be opened prior to cold leg manways, and that cold leg dams be installed prior to hot leg dams. The removal of these items is in the reverse order.

- Vital Electrical Bus Availability - Both trains of vital power were available. Operations would not release busses or alternate power sources for work. Draindown was held up pending completion of emergent work in the switchyard.

Overall, operational controls were well planned and executed. The off-normal Unit 2 turbine shutdown was well handled.

c. Technical Specification Compliance

Licensee compliance with selected TS LCOs was verified. This included the review of selected surveillance test results. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, and switch positions, and by review of completed logs and records. Instrumentation and recorder traces were observed for abnormalities. The licensee's compliance with LCO action statements was reviewed on selected occurrences as they happened. The inspectors verified that related plant procedures in use were adequate, complete, and included the most recent revisions.

d. Physical Protection

The inspectors verified by observation during routine activities that security program plans were being implemented as evidenced by: proper display of picture badges; searching of packages and personnel at the plant entrance; and vital area portals being locked and alarmed.

e. Jumpers and Lifted Leads

The inspectors reviewed the Jumper/Lifted Lead book in each unit and AP 0010124, Control and Use of Jumpers and Disconnected Leads, Rev.

25. Each approved jumper/lifted lead request had received extensive review and approval, including technical review by an STA, 50.59 review when appropriate, approval by an NPS or ANPS; and FRG review and Plant Manager approval when appropriate. Both electrical and mechanical jumpers/lifted leads were included. Tags were hung at the location of the jumper/lifted lead (the inspectors verified two tags located inside an electrical cabinet). The inspectors noted that a total of about nine RTGB annunciators in the two units were affected by jumpers/lifted leads. One or all of the inputs to these annunciators were disabled. However, this was not readily apparent for operators. There were no stickers on the annunciators or entries in the related annunciator panel status books to ensure operator awareness. This was identified to the licensee for review.

Jumpers/lifted leads are temporary modifications to the plant. Several jumpers/lifted leads had been in place for over two years. The inspectors verified that these were periodically reviewed by the licensee to ensure that permanent modifications were being pursued.

f. Facility Review Group

The inspectors attended two FRG meetings; reviewed FRG records; reviewed TS 6.5.1, Facility Review Group; and reviewed AP 0010520, Rev. 21, Facility Review Group. During the two meetings, the FRG reviewed and approved four PCMs, 10 permanent Procedure Changes, three Temporary Changes to procedures, two Contractor Procedures, one Instruction Manual change, two Jumper/Lifted Lead requests, one NPWO, and one Work Process Sheet. The FRG reviewed items that TS required them to review and also many others, such as non-safety-related procedure changes. A copy of each item to be reviewed was present at the FRG meeting, with proposed procedure changes written clearly in red to facilitate quick review. A representative from the sponsoring department was present to describe the changes and answer questions as needed. If any FRG member was not satisfied with an item, it was sent back to the sponsoring department for further answers or revisions to be presented at a future FRG meeting. The review of each item was done quickly and efficiently.

The inspector verified that requirements for minimum FRG meeting quorum, FRG member training, and appointment of alternate members were met. TS requirements were implemented by AP 0010520. FRG member training records and meeting minutes were well organized. The inspector noted that the required written appointment of each alternate member was accomplished by inclusion in the minutes of an FRG meeting, and that there was no approved list of alternate members. This was identified to the FRG Chairman (Plant Manager) for review.

As FRG review of an item was completed, the FRG chairman ensured that no member had any objections to approval, then signed the item with Plant Manager approval. At one of the FRG meetings, the Plant

Manager was the FRG Chairman. In the other FRG meeting, the Plant Manager was not present and the Operations Superintendent was alternate FRG Chairman. The inspector found that it was common practice for an alternate FRG chairman to sign a required Plant Manager approval on documents. However, AP 0010520 did not authorize an alternate FRG chairman to sign for required Plant Manager approval. This was identified to the Plant Manager for review.

g. Licensee Control of Important Equipment Not Included in Technical Specifications.

During the inspection period, as a response to IN 92-06, Reliability of ATWS Mitigation System and Other NRC Required Equipment Not Controlled by Plant TS, the inspectors reviewed implementation aspects of the ATWS rule (10 CFR 50.62). The IN addressed perceived problems at other utilities in keeping the ATWS equipment in service. Notices of Violation against the rule itself had been issued at other sites even though no TS had been issued in the area.

ATWS equipment provides an alternate means for emergency insertion of CEAs [rods] to terminate nuclear power generation. ATWS equipment was not required to be safety-related. At this site, the equipment was bought as safety-related, but was not addressed as safety-related.

Both units at this site have the ATWS equipment installed and operational. Routine plant tours of the control rooms and RABs have not indicated problems with this utility maintaining their ATWS equipment. Daily and weekly tours have found the equipment in service and functional. Actuation circuitry and initiation components have been found to be configured properly.

Procedures existed that calibrated the ATWS equipment and checked its functionality on a routine basis. Different features of the system have been checked and calibrated as required on a monthly, six month, or outage basis.

Inspector analysis of the administrative features surrounding the ATWS equipment revealed that additional controls may be necessary. The rationale for the additional controls are discussed below:

(1) Unit 1 AP 1-0010123, Rev 82, Administrative Control of Valves, Locks and Switches, provided control methods for selected components. At the time the ATWS was added, the keys that control ATWS bypass features were added to procedure Appendix "A", Key Locker Index. This got the ATWS keys accounted for on a quarterly basis, and the keys were required to be checked in and out of the controlled key locker when used.

Procedure section 7.3 discussed the "Valve, Switch Deviation Log". The log was used to maintain a record of other-than-normal equipment configuration.

The ATWS bypass locks and associated circuitry were physically located in the ESFAS cabinets, which contained many locks for safety-related channels, and had locked doors. Section 8.11 of the above procedure listed the ESFAS cabinet lock and door keys but neither it, nor other instructional sections of the procedure, listed or dealt with ATWS keys. This omission meant that the keys were not required to be entered in the "Valve, Switch Deviation Log".

The equivalent Unit 2 procedure required ATWS bypass key usage be logged in the above mentioned log for that unit for configurational purposes. The ATWS bypass keys were also discussed in the Unit 2 procedure's instructional text. The operators on both units, out of force of habit from the in-use proceduralized methodology for controlled keys in general, would have utilized the log for the subject keys in any case.

The licensee agreed to change Unit 1 AP 1-0010123 to match the Unit 2 procedure regarding ATWS bypass key configuration controls.

(2) On both units, the placing of an actuation circuit in bypass with a key would remove the ATWS trip feature from one CEA MG set. Since the ATWS trip must open the output of both CEA MG sets to be effective, the probability of the ATWS logic circuit producing a reactor trip would go to zero - essentially placing the ATWS system out-of-service. Although the other ATWS actuation circuit would still be available for tripping the second MG set, power from the first MG set would maintain the CEAs' positions unless the primary safety-related trip feature (RPS) had deenergized the CEAs. This situation was a departure from the logic change associated with the bypassing of a RPS trip channel in that the RPS trip logic changed and the proximity to trip was increased.

The above fact was not general knowledge to the licensee staff. There was no general information available/apparent to the operations staff. I&C personnel were aware of the facts.

Operations has agreed to place plastic tags on the ATWS actuation circuit bypass keys stating to the effect that bypass of the circuit would place the ATWS system out of service. Further, the licensee was considering changing both units' administrative control of valves, locks, and switches procedures to indicate this information.

The above licensee interactions indicated a positive commitment to improvement.

Plant controls and response to events during various evolutions were excellent. One violation was identified in this area concerning a capped containment pressure transmitter sensing line. The inspector had no further questions at this time.

3. Surveillance Observations (61726)

Various plant operations were verified to comply with selected TS requirements. Typical of these were confirmation of TS compliance for reactor coolant chemistry, RWT conditions, containment pressure, control room ventilation, and AC and DC electrical sources. The inspectors verified that testing was performed in accordance with adequate procedures, test instrumentation was calibrated, LCOs were met, removal and restoration of the affected components were accomplished properly, test results met requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel. The following surveillance tests were observed:

a. OP 1-0640020, Rev 33, ICW System Operation [1B ICW pump]

b. OP 1-2200050, Rev 61, Emergency Diesel Generator Periodic Test and General Operating Instructions [1B EDG, three separate tests]

On April 3, the inspector observed the 20th weekly idle start test of 1B EDG per OP-1-2200050B, 1B Emergency Diesel Generator Periodic Test and General Operating Instructions. This test was to be the last in a series of 20 weekly starts to meet TS Table 4.8-1 requirements - based on the previous failure history. The EDG started and ran properly at idle speed and at rated speed, however following EDG warmup, the control room operator was unable to close the EDG output circuit breaker. The licensee aborted the test and subsequently stopped the EDG per the procedure. The inspector had no further questions concerning these actions.

Troubleshooting at the EDG control cabinet per NPWO 5139/65 found the "frequency relay" K49 not functional. This relay's function was to prohibit EDG output breaker closure until an EDG frequency near 60 Hz (above 54 Hz) is reached. The failed relay was subsequently found to function properly in the shop. Since the relay failure mode would require detailed investigation, a replacement relay, identical but not dedicated for the proper quality level, was tested for installation. The inspector observed that the new relay performed identically to the old one. Relay test performance is further discussed below. Following relay installation, the licensee's successful idle start retest was also observed by the inspector. Following the EDG retest, the licensee continued to declare the EDG

"out of service" but functional pending completion of the new relay's dedication package.

During the shop testing of the new K49 relay, the inspector observed that the new relay performed identically to the old one (i.e., the contacts were closed at low frequency and opened at about 62.5 Hz). Neither relay functioned in the manner the inspector expected (i.e., relay contacts would remain open until a predetermined frequency was reached - then close to enable the EDG output circuit breaker to close). The inspector requested the licensee to evaluate this observation.

The existing relays were Westinghouse style 177C717G03 60 Hz/120 V over-frequency relays. Westinghouse instruction sheet I.L. 14443 described a 1-2 Hz differential between open and close functions, but was ambiguous concerning whether or not the contacts open or close on increasing frequency. Also, the relay specified in the EDG vendor manual, on drawing 8770-2421, was Westinghouse relay style 117C717G03, not 177C717G06. The licensee confirmed with Westinghouse, Morrison-Knutson, and EBASCO that:

- The vendor manual number was a typographical error,

- Westinghouse relay style 177C717G03 was intended to be an over-frequency relay whose contacts would be open above the setpoint.

- The design basis, as described in FSAR section 8.3.1.1.7.d. and Figure 8.3-5 was for the relay contacts to be open below the setpoint to prohibit EDG output circuit breaker closure until the EDG reached at least 90 percent of rated voltage and frequency.

The relays, as installed, failed to perform this function. The installation, as installed, deviated from a written commitment in the FSAR. Specification of improper relays was considered to be a generic design issue. The NRC vendor branch and industry organizations were notified. Further enforcement action was not considered because of the licensee's extremely prompt and effective corrective action and because the existing installation's actual performance met safety requirements.

The licensee found that the EDG frequency permissive function was performed on St. Lucie Unit 2 and at Turkey Point by a different relay, a WILMAR ELECTRONICS model 20-050 relay. That relay was also qualified for safety-related service. The licensee prepared PCM 116-192M, procured and tested the relays, and installed them on both 1A and 1B EDGs on April 4 per the PCM and NPWO 5141/65. The EDGs were subsequently tested per the PCM package and temporarily changed versions of OP 1-2200050A and B. Since the EDGs were not fast start tested, the last fast start times were evaluated as still bounding by

adding an increased relay actuation time to the previous strip chart data.

The licensee's response upon discovering this design error was notably swift and thorough, involving coordination of a number of departments and vendors.

c. 1A EDG retest on April 26 following replacement of the 16 cylinder radiator fan idler shaft. The fan belt appeared loose and flapped excessively, about two inches deflection on each of the short spans. The vibration analysis crew measured about 70 mils vibration. The EDG remained out of service for further corrective action.

d. OP 1-0700050, Rev 37, Auxiliary Feedwater Periodic Test [1C AFW pump].

e. I&C 2-1130050, Rev 7, Loose Parts Monitoring System Periodic Test.

f. MP 2-0950184, Rev 1, Fast Dead Bus Transfer Surveillance Test. This test was properly aborted when the B-train 4 KV circuit breaker for the generator auxiliary transformer failed to close. Subsequent troubleshooting per the recently written large breaker troubleshooting procedure MP-0920069, Rev 0, proved that the circuit breaker was satisfactory but the synchronizing switch in the control room had failed. A piece of trash had gotten inside and jammed the switch action.

g. The inspector observed periodic testing of the Main, Startup, and Auxiliary transformer control circuits and alarms per OP 1-0910051, Rev 8, Main Transformer Periodic Test, OP 1-0910050, Rev 12, Startup Transformer Periodic Test, and OP 1-0910052, Rev 7, Auxiliary Transformer Periodic Test, respectively.

During the test of 1A main transformer, the operator closed a wrong switch by mistake but recognized the error and corrected it. There were no bad results from this error. Review of the procedure and work site showed a human factors shortcoming in the procedure. Procedure section 8.6 listed switches numbered TS-2 through TS-15, but the procedure step numbers were one number off [step 1 through 14], and easily mistaken for the switch number. The switches themselves had adjacent small text label plates but were numbered on the panel face in pencil with incomplete nomenclature [just a number]. The numbers resembled the procedure step number more than the switch number. Step 8.7 then stated "Place TS-7, 8, 9, 10, 11, 12 in TEST position." The operator placed TS-8, 9, 10, 11, 12, and 13 in TEST. Switch TS-13 involved a different function. After reading the label text, the operator stopped and corrected the switch alignment. This was identified to the site procedures group for correction.

The 1A main transformer control cabinet contained a number of devices that had a green colored ooze on the wire terminals. Examples included undervoltage relays 1 through 6, current transformers 1 through 6, and relays TR-1 and TR-2. The green color came from corrosion caused by breakdown of aging PVC wire insulation found in certain lots of such wire manufactured about 20 years ago. The insulation gives off a liquid that turns corrosive in air. The nonsafety-related main transformer controls are serviced by the utility's system protection division. This condition was identified to the plant maintenance staff for coordination of future repair.

During the test of the 2B startup transformer controls, a large relay hung up, causing unexpected indications. The relay ultimately started smoking. The operator recognized the unusual response and promptly summoned supervisory aid. That circuit was deenergized pending repair.

The inspector had no further comments on this surveillance.

h. The inspector observed the performance of OP 2-0400050, Rev 12, Periodic Integrated Test of the Engineered Safety Features, from the control room and 2B EDG room. This test had a number of sections that were performed independently, however the main body of the test simulated a loss of offsite power concurrent with a LOCA. This forced EDGs to fast start and automatically feed the safety busses, and all the safety-related pumps and equipment to start. EDG 2A output circuit breaker closed in 8.54 seconds and EDG 2B output circuit breaker closed in 9.86 seconds. The standard was 10 seconds. Equipment not working during the test included:

- 2B Containment Spray Pump Automatic Actuation [The pump started manually],

- 2B1 RCP Oil Lift Pump [the circuit breaker was faulty], and

- MFIV 09-1B operated when tested with the AFAS test, but failed to fully close during the subsequent MSIS test. A sticky limit switch limited valve closure to 90 percent open.

i. The 1B ICW pump was returned to service at the beginning of the inspection period after being modified with a self lubricating alteration. PCM 281-189 removed the existing need for support equipment to process and to supply pump discharge water to lubricate the water bearings and pump packing area. The 1B pump became the third and final Unit 1 pump to be modified. Post-modification pump surveillance per OP 1-01010020 established new pump baseline data per ASME Code Section XI.

j. AP 1-0010125, Rev 87, Schedule of Periodic Tests, Checks, and Inspections, Check Sheet 6, Test Shield Building Ventilation System, B-train. This was a 10-hour test run of the system by plant

operators. During the test, the inspector observed that the 6B fan discharge damper counterweight arm was installed at a different angle than the equivalent item on the 6A fan, and that it had 14 weights while the 6A fan damper had 2 weights. After the surveillance run was complete, the inspector observed that the 6B damper would not quite close, though free, because of the amount of counterweight. In contrast, the 6A fan damper required significant effort to open. Both ventilation trains have routinely demonstrated that they would perform their safety function in spite of the dampers. The licensee group developing damper PMs reviewed the situation, relocated the 6A counterweight arm to match the 6B arm and adjusted the weight on both dampers. Both dampers now function well.

During this period the conduct of surveillance activities and response to unexpected findings was excellent.

4. Evaluation of Licensee Self-Assessment Capability (40500)

The inspectors evaluated the licensee's self-assessment programs to determine whether they contributed to the prevention of problems by monitoring and evaluating plant performance, providing assessments and findings, and communicating and following up on corrective action recommendations.

Portions of this evaluation were accomplished throughout the SALP period [November 1, 1990 to May 2, 1992] by various inspectors and the results are found in multiple IRs, as follows:

- IR 335.389/91-01, paragraph 6 discussed licensee audit and reviews of the Emergency Plan;

- IR 335,389/91-03, paragraph 1 and Appendix A (finding 91-03-09) discussed licensee self-audits prior to an EDSFI;

- IR 335,389/91-04, paragraph 2.b discussed QA audit reviews in performance monitoring, refueling activities, and breaker modification;

- IR 335,389/91-09, paragraph 7 discussed 10 CFR Part 21 closeouts under the licensee's Corrective Action Report program;

- IR 335,389/91-10, paragraph 2.b discussed licensee audits of operations, and paragraph 7 discussed CNRB review of plant performance;

- IR 335,389/91-16, paragraph 9 discussed management efforts in work control programs;

- IR 335, 389/91-18, paragraph 3 discussed the licensee assessment of the MOV program at the plant;

- IR 335,389/91-201, paragraph 2.5 discussed licensee audit findings in the area of service water system;

- IR 335,389/92-02, paragraph 3 discussed audit in the areas of offsite dose, process control, and the radiological environmental program;

- IR 335,389/92-03, paragraph 2 discussed implementation of changes within the ISEG program; and,

- IR 335,389/92-04, paragraph 2.b discussed licensee audits in surveillance, QA program, and performance monitoring.

The above documents reported on diverse areas under various programs at the site. They noted that several areas, such as the operations, instrument and control, electrical, and chemistry were improving or continuing to take positive actions. Two team inspections however indicated areas where improvement was needed or weakness was apparent. The MOV program was found to be in the early phases of implementation addressing most generic letter recommendations but there were some concerns about potential deviations from the subject letters and there was a lack of detail in some MOV program aspects. The service water team found insufficient depth in certain areas of assessment. In contrast, an EDSFI team inspection considered the licensee's preparations to be so significant that they constituted a safety improvement.

During the day to day inspections, the licensee had several notable events to which they responded well. Unit 1 MSIV air control [support] solenoid valves had a moisture entry problem that was resolved in a proper manner. Engineering and the electrical department had overall excellent corrective action on an HFA relay latch manufacturing problem that arose during the Unit 1 refueling outage and a diesel generator underfrequency relay problem that was identified in 1992 after the Unit 1 outage. Although they were slow to realize a diesel fuel oil contamination problem initially, the licensee responded well with an extremely solid response. On the whole, the licensee's approach to plant operations during this SALP evaluation period was very conservative and demonstrated continued critical self assessment.

Previous inspection reports have discussed electric motor failures at this site in both safety and non-safety related applications. The failures were as follows: Unit 1 1A ICW pump motor in May, 1990 (failed megger); Unit 1 1A heater drain pump motor in April, 1990; and Unit 1 1C CCW pump motor in February, 1991. In response to these failures to G.E. motors of different model types, the licensee has performed several evaluations and developed a methodology for rewinding these motors utilizing a vendor, their own electrical department, and site QA personnel to qualify the rewind process under the extensive EPRI guidance documents. To date, the above motors and two additional G.E. motors have been rewound. A summary of the site's analysis and planned activities inclusive of the Unit 2 plans are discussed in FPL letter JPN/ESI-92-086 dated February 28, 1992 [from A.R. Hall to W.N. Dean]. To date, the corrective actions and

planned actions have been well thought out and well enacted. The actions have been conservative in maintaining plant reliability and demonstrate excellent self assessment at both the maintenance and engineering levels.

The inspectors conclude that the licensee management strongly supports self identification of problems and that the utility has demonstrated a continuous pattern of success in recognizing and addressing problems. Individual exceptions do not destroy this pattern.

5. Maintenance Observation (62703)

Station maintenance activities involving selected safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review: LCOs were met; activities were accomplished using approved procedures; functional tests and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; and radiological controls were implemented as required. Work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment. Portions of the following maintenance activities were observed:

a. NPWO 4883/66 - HVE 10B Fan Motor Replacement (MP 0940062C, R11, The Overhaul of Motors).

b. NPWO 8361/62 - Sequence of Events Recorder Repair and Troubleshooting.

c. NPWO 7254/63 - CEDM NO. 8 Control Element Drive Coil Power Supply Troubleshooting.

d. NPWO 0962/62 - 2B EDG 12 Cylinder Diesel Fan Shaft Replacement. This job was inefficient in that the procedure did not specifically require all three fan belt drive hubs to be aligned following the job, and shop personnel ignored the driving hub by aligning only the idler hub and the fan hub. The procedure also did not specify where to measure belt tension. In short, at the post-work test, the belt was loose and misaligned, requiring further work. The workmanship was corrected prior to returning the EDG to service. The work documents were identified to maintenance shop engineers for generic correction.

e. NPWO 4633/66 - 2A LPSI Pump Breaker Change Out [nine year cyclical overhaul].

f. NPWO 4953/66 - MOV 3517, 2A LPSI to SDC Heat Exchanger Isolation Valve, Spring Pack Replacement.

g. NPWO 4960/66 - 2A HPSI Breaker Anti-pumping "Y" Relay Replacement.

h. NPWO 5117/65 (Unit 1) and 4936/66 (Unit 2) - Inspection of Latching-Type HFA Relays. The inspector observed testing and inspection of 14 of 16 Unit 1 relays and 4 of 6 Unit 2 relays. All latched properly. The remaining relays had been recently inspected under other NPWOs. These relays had been previously inspected during the Fall 1991 refueling outage and some had been replaced or adjusted. The potential for drift was considered small but was an unknown factor. This present inspection confirmed that the relays had not changed characteristics.

i. NPWO 7146/63 - Test Engineered Safeguards Cabinet Power Supplies for Voltage and Ripple - Replace Bad Power Supplies. This work was further corrective action for a failed instrument power supply serving channel MD MSIS for 1A SG. The acceptance criteria for voltage was per the component specification. The ripple criterion of 200 mv peak-to-peak was conservatively specified by the shop engineer. Five of 24 power supplies failed and were replaced. The licensee was considering a possible replacement, which would include improved electrical lead connections, through their engineering division. This work was additionally controlled by AP 0010142, Rev 8, Unit Reliability - Manipulation of Sensitive systems. The inspector found that field activities were well performed and documented.

j. NPWO 7202/64 - Calibrate ICW Flow Instruments FIS-21-9A and 9B. The specialist also found a broken face plate screw and a rusted terminal board, which he annotated on the NPWO. Work request 92003451 was subsequently generated to initiate repair.

k. NPWO 1114/62 - Test Both A and B Train Low Range Main Steam Safety Valves. Each SG had 8 safety valves under the cognizance of TS 3/4.7.1. The TS required, by specifying individual valve numbers, that 4 safety valves per SG be verified to be set at 1000 psia +/- 1 percent [10 psi], and that the other 4 be verified to be set at 1040 psia +/- 1 percent. This NPWO addressed the 8 total valves with the 1000 psia setpoint. The NPWO specified the controlling procedure to be GMP-0705, Rev 17, Main Steam Safety Valve Maintenance and Setpressure Testing. The cover page boldly announced the procedure had been recently been rewritten and should be read completely - a good practice. The procedure included well marked QC hold points.

The inspector observed test performance on April 21. The licensee was using two test gages, a 1500 psig gage and a 200 psig gage. These were relatively small gages with 4 1/2 inch diameter faces that stated on the face that they had 1/4 of 1 percent accuracy. Though 1500 psig gage M-195 had 5-psi divisions, implying that it could be read to 2 1/2 psi or half a division, it had a large label on the side stating that it had been calibrated to only 1 percent accuracy [+_- 15 psi]. 200 psig gage M-201 also had a large 1 percent

calibration [+ - 2 psig] label on its side. Procedure GMP-0705 section 8.0, Material and Equipment Required, plainly specified that all test gages shall have an accuracy of 0.5% of full scale. Worksite review of the of these gages' calibration sheets showed that 1500 psig gage M-195 was actually calibrated much closer than 1 percent, but 200 psig gage M-201 was actually varying over a 2 psig [1%] range. The test crew stopped work, obtained another 200 psig gage that met the requirements, and retested three valves previously set using the out-of-specification gage. They also verified that the Unit 1 safety valves set in the Fall of 1991, were in fact properly set.

Failure to follow (implement) GMP-0705, Rev 17, Main Steam Safety Valve Maintenance and Setpressure Testing, was a violation of TS 6.8.1.c. which required procedures for safety related activities be established, implemented, and maintained for surveillance and test activities of safety-related equipment. This is identified as VIO 389/92-07-04, Failure to Follow Procedure for Setting Steam Generator Safety Valves.

As a result of this occurrence, the licensee also planned to review several relief and safety relief valve setting procedures regarding gage size, range, and type; gage calibration range and technique; and procedural verification of essential parameters at the time of the test.

1. On April 3, during an attempt to fill a SIT, the 2A HPSI pump failed to start. The pump's 4160 Volt breaker failed to close. Operations generated NPWO 4960/66 for its repair.

   Electrical maintenance evaluated the condition via the administrative constraints of above NPWO and newly-generated maintenance procedure MP 0920069, Rev 0, Troubleshooting 4 KV/6.9 KV Breaker Failures. The procedure was very useful in identifying the breaker problem. The breaker was repaired within hours of the failure, greatly limiting the amount of time the component/train was in an LCO situation.

   Referring to Unit 2 drawing 2998-327 for the 2A HPSI pump breaker 2A3-1 cubicle, the Westinghouse 50-DHP-250 4160 Volt breaker for the pump had a failed "Y" anti-pumping relay. With the failure of this relay, the breaker would not close. The relay had four contacts, two of which were not used. One of the unused contacts had loosened in the relay, moved within the relay, and blocked further relay operation. A new relay was installed and successfully tested (pump started).

   Electrical maintenance and the operational staff are reviewing the situation for root cause. Several factors such as breaker use and breaker overhaul period were being considered. The HPSI pump was being routinely used to fill two weeping SITs on a once to twice daily basis. The filling, which was due to slow leaking valves, had

been effect for most of the fuel cycle. The breaker was scheduled for its nine year overhaul this upcoming (April 20) maintenance and refueling outage. The electrical staff was planning to tear down the "Y" relay for investigation.

Most activities observed, particularly the HPSI circuit breaker troubleshooting, were acceptable and conservative. The licensee promptly initiated corrective action on observations d and k above, where shop performance elements were weak.

6. Receipt and Handling of New Fuel (Unit 2)(60705)

During this period, the inspectors observed the receipt and handling of new fuel for Unit 2. The review included observation of truck unloading; shipping cask operations; fuel unpacking and lifting into dry storage, including crane operations; repacking the empty containers; and cleanliness inspection of dry storage. The licensee's reactor engineering group had preplanned and supervised the receipt. The operators and maintenance crew handled the shipping containers and the fuel properly with due care and efficiency. A vendor representative and a health physics technician were present during the several observations. The containers inspected were in good shape, well preserved, and properly packed by the vendor. Records being generated at the time were satisfactory. Documents reviewed at the worksite included:

OP 1610020, Rev 8, Receipt and Handling of New Fuel and CEAs, and

ONOP 2-1600030, Rev 5, Accidents Involving New or Spent Fuel.

The licensee's new fuel receipt process was well polished. The inspectors had no further questions concerning the receipt of new fuel.

7. Fire Protection Review (64704)

During the course of normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control of hazardous chemicals, ignition source/fire risk reduction efforts, and fire barriers.

Fire protection program implementation was apparent.

8. Review of Periodic and Special Reports (90713)

The inspector reviewed special report L-92-117 dated April 28, 1992. It was issued per TS 4.8.1.1.3 and 6.9.2, and addressed a failure of the 1B EDG to load on April 3. This subject is discussed in paragraph 3.b. of this report. The inspector had no further comment concerning the special report. This item is closed.

The inspector reviewed a 10 CFR Part 21 initial notification dated April 1, 1992. The formal written notification was forwarded in letter L-92-119 dated April 28. It addressed crack-like indications found in a 3-inch-diameter Monel 400 tee fitting supplied by Tioga Pipe Supply Co. The material did not meet requirements of the ASME SB564 specification. Of the seven items received, one was analyzed in the laboratory and six were returned to the vender. The inspector had no further questions in this area. This item is closed.

9. Onsite Followup of Written Nonroutine Event Reports (Unit 1) (92700)

The following LERs were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. The LERs were reviewed in accordance with the current NRC Enforcement Policy.

a. (Closed) LER 335-92-001, Fuel Handling Building Ventilation Radiation Monitor Out of Service Due to Personnel Error. This LER discussed a licensee-identified violation of TS 3.3.3.10, Radioactive Gaseous Effluent Monitoring Instrumentation. The fuel handling building ventilation radiation monitor was required to be operable at all times but was removed from service for about 23 hours by a series of personnel errors and without knowledge of the control room operators. The licensee's event analysis and resultant corrective action plans appear to be thorough and consistent with corrections for LER 335-92-003 below.

This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the Enforcement Policy. It is identified as NCV 335/92-07-01, Fuel Handling Building Ventilation Radiation Monitor Out of Service Due to Personnel Error.

b. (Closed) LER 335-92-003, Containment Atmosphere Particulate and Gaseous Radioactivity Monitors Out of Service Due to Personnel Error. This LER discussed a licensee-identified violation of TS 3.3.3.1, Radiation Monitoring Instrumentation Channels, and 3.4.6.1, RCS Leakage Detection Systems. Containment isolation valves were inadvertently left closed following periodic valve stroke testing. The licensee found several contributing factors, including no independent verification of restoration, a burned out light bulb, and weakness in reviewing the details of radiation monitor readings. Corrective actions addressed all safety-related valve stroke time procedures, including independent verification of post test restoration. Corrective actions also included a significant upgrade of the radiation monitor log sheets to require checks of instrument trends.

This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the Enforcement Policy.

It is identified as NCV 335/92-07-02, Containment Atmosphere Particulate and Gaseous Radioactivity Monitors Out of Service Due to Personnel Error.

The licensee has taken extensive corrective action for these two problems.

10. Onsite Followup of Events (Units 1 and 2)(93702)

A nonroutine plant event was reviewed to determine the need for further or continued NRC response, to determine whether corrective actions appeared appropriate, and to determine that TS were being met and that the public health and safety received primary consideration. Potential generic impact and trend detection were also considered.

On April 21, at 2:38 a.m., the reactor operator manually tripped Unit 2 from 12 percent power during a planned shutdown for refueling. The turbine did not trip from remote signals from the reactor trip switchgear nor from the control board pushbutton. The Nuclear Watch Engineer manually tripped the turbine locally at the turbine stand. This is discussed further in paragraph 2b.

The operators' response to this unexpected event was excellent.

11. Followup (Units 1 and 2) (92701)

a. Followup of Unresolved Items

(Closed - Units 1 and 2) URI 335,389/92-03-01, Evaluate Operability of Containment Cooling System Relief Dampers.

This item concerned an ISEG surveillance finding in March, 1990, that a number of Unit 1 containment ventilation pressure relief dampers were painted shut. The record did not indicate that the dampers had been determined to be operable during the time they were painted over.. FPL engineering subsequently performed engineering evaluation JPN-PSL-SEMS-92-002, REV 0, assessing the containment fan cooler relief dampers' historical operability. This study found that, at design pressure, the force to open each relief damper would be about 55 pounds - far greater than the force actually exerted by the person who opened the dampers. This study also found that, of the eight damper assemblies installed, if only one damper assembly opened, the ventilation system would not experience excessive differential pressure. The computer program used for the analysis would not work if all damper assemblies were assumed failed closed, so that more extreme analysis was not completed. The inspector had no further questions. This URI is closed.

(Closed - Units 1 and 2) URI 335,389/91-05-01, Drug Testing Program Elements.

This St. Lucie item concerned weekend and holiday drug testing. During an inspection at the Turkey Point facility, the cognizant security inspector determined that the item was satisfactory throughout the corporate structure, including both Turkey Point and St. Lucie. This is discussed in IR 250, 251/91-40. This URI is closed.

b. Followup of Regional Requests

During this period, the inspectors conducted two surveys per Region II directions and returned the results to regional contacts:

- Identification of present or past waste dumps at reactor sites, and
- Completion of a licensee staffing matrix.

12. Exit Interview

The inspection scope and findings were summarized on May 8, 1990, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
335,389/91-05-01,	closed	URI - Drug Testing Program Elements, paragraph 11a.
335,389/92-03-01	closed	URI - Evaluate Operability of Containment Cooling System Relief Dampers, paragraph 11a.
335/92-07-01	closed	NCV - Fuel Handling Building Ventilation Radiation Monitor Out of Service Due to Personnel Error, paragraph 9a.
335/92-07-02	closed	NCV - Containment Atmosphere Particulate and Gaseous Radioactivity Monitors Out of Service Due to Personnel Error, paragraph 9b.
389/92-07-03	open	VIO - Isolation of Containment Pressure Sensing Line Without Placing Effected Instrumentation Channels in Trip or Bypass as Required, paragraph 2a.
389/92-07-04	open	VIO - Failure to Follow Procedure for Setting Steam Generator Safety Valves, paragraph 5k.

13. Abbreviations, Acronyms, and Initialisms

AFAS	Auxiliary Feedwater Actuation System
AFW	Auxiliary Feedwater (system)
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ATTN	Attention
ATWS	Anticipated Transient Without Scram
cc	Cubic Centimeter
CCW	Component Cooling Water
CDF	Core Damage Frequency
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
CNRB	Company Nuclear Review Board
DEH	Digital Electro-Hydraulic (turbine control system)
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution System Functional Inspection
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
FIS	Flow Indicator/Switch
FPL	The Florida Power & Light Company
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
GL	[NRC] Generic Letter
GMP	General Maintenance Procedure
HFA	A GE relay designation
HPSI	High Pressure Safety Injection (system)
HVE	Heating and Ventilating Exhaust (fan, system, etc.)
Hz	Hertz (cycle per second)
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IR	[NRC] Inspection Report
ISEG	Independent Safety Engineering Group
JPN	(Juno Beach) Nuclear Engineering
KV	KiloVolt(s)
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPSI	Low Pressure Safety Injection (system)
MFIV	Main Feed Isolation Valve
MG	Motor Generator

MMP	Mechanical Maintenance Procedure
MOV	Motor Operated Valve
MP	Maintenance Procedure
MSIS	Main Steam Isolation Signal
MSIV	Main Steam Isolation Valve
mv	millivolt
NCV	Non-Cited Violation (of NRC requirements)
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PCM	Plant Change/Modification
PM	Preventive Maintenance
PSI	Pounds Per Square Inch
PSIA	Pounds Per Square Inch Absolute
PSL	Plant St. Lucie
PT	Pressure Transmitter
Pub	Publication
PVC	PolyVinylChloride
QA	Quality Assurance
QI	Quality Instruction
RAB	Reactor Auxiliary Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
Rev	Revision
RPS	Reactor Protection System
RTGB	Reactor Turbine Generator Board
RWT	Refueling Water Tank
SALP	Systematic Assessment of Licensee Performance
SB	Safety Train B
SDC	Shut Down Cooling
SG	Steam Generator
SIT	Safety Injection Tank
St.	Saint
STA	Shift Technical Advisor
TQR	Topical Quality Requirement
TR	Temperature Recorder
TS	Technical Specification(s)
URI	[NRC] Unresolved Item
VIO	Violation (of NRC requirements)