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

Report Nos.: 50-250/85-44 and 50-251/85-44

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

Docket Nos.: 50-250 and 50-251 License Nos.: DPR-31 and DPR-41

Facility Name: Turkey Point 3 and 4

Inspection Conducted: December 9, 1985 - January 13, 1986

Inspectors: S. Guenther — Feb 19, 1986
T. A. Peebles, Senior Resident Inspector — Date Signed

S. Guenther — Feb. 19, 1986
D. R. Brewer, Resident Inspector — Date Signed

Approved by: S A Elrod — FEB 20, 86
Stephen A. Elrod, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed 174 direct inspection hours at the site, including 22 hours of backshift inspection, in the areas of licensee action on previous inspection findings, annual and monthly surveillance, maintenance observations and reviews, operational safety, engineered safety features walkdown, independent inspection, and plant events.

Results: Violation - Failure to meet the requirements of Technical Specification (TS) 6.8.1.

REPORT DETAILS

1. Licensee Employees Contacted

*C. M. Wethy, Vice President - Turkey Point
*C. J. Baker, Plant Manager - Nuclear
*D. D. Grandage, Operations Superintendent - Nuclear
T. A. Finn, Operations Supervisor
J. Crockford, Assistant Operations Supervisor
J. Webb, Operations/ Maintenance Coordinator
*K. L. Jones, Technical Department Supervisor
B. A. Abrishami, Inservice Test (IST) Supervisor
D. Tomaszewski, Plant Engineering Supervisor
D. A. Chaney, Corporate Licensing
*J. Arias, Regulation and Compliance Supervisor
R. L. Teuteberg, Regulation and Compliance Engineer
R. Hart, Regulation and Compliance Engineer
*J. W. Kappes, Maintenance Superintendent - Nuclear
O. E. Suero, Electrical Maintenance Supervisor
R. A. Longtemps, Mechanical Maintenance Supervisor
E. F. Hayes, Instrument and Control (I&C) Maintenance Supervisor
V. A. Kaminskas, Reactor Engineering Supervisor
R. G. Mende, Reactor Engineer
R. E. Garrett, Plant Security Supervisor
P. W. Hughes, Health Physics Supervisor
W. C. Miller, Training Supervisor
J. M. Donis, Site Engineering Supervisor
J. M. Mowbray, Site Mechanical Engineer
L. C. Huenniger, Start-up Superintendent
R. H. Reinhardt, Acting Quality Control (QC) Supervisor
R. J. Acosta, Quality Assurance (QA) Superintendent
W. Bladow, Quality Assurance Supervisor
J. A. Labarraque, Performance Enhancement Program (PEP) Manager
D. W. Hasse, Safety Engineering Group Chairman
G. M. Vaux, Safety Engineering Group Engineer
T. C. Grozan, Licensing Engineer

Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, mechanics, electricians and security force members.

*Attended exit interview.

2. Exit Interview

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant Manager - Nuclear and selected members of his staff.

An exit meeting was conducted on January 14, 1986, with those individuals identified in paragraph 1 above. The areas requiring management attention were reviewed.

One violation was identified: Failure to meet the requirements of TS 6.8.1, two examples; in that (1) Operating Procedure (OP) 0202.1 was inadequate because it allowed the units to be operated at elevated temperatures and pressures while the cold leg accumulators were out of service, contrary to the Final Safety Analysis Report (FSAR) (paragraphs 3 and 7); and (2) failure to implement adequate maintenance instructions for returning equipment to service (paragraph 6) (250,251/85-44-01).

The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. The licensee acknowledged the finding without dissenting comments.

3. Licensee Action on Previous Inspection Findings (92702)

   a. Performance Enhancement Program (PEP) Summary

      The PEP, Project 10 tracks the progress on the commitment to upgrade the plant's TS. During the meeting with Region II on October 23, 1985, the licensee's Vice President reiterated the licensee's position that they would submit TS revisions that would be as close to the Standard TS (STS) as possible. The only exceptions that would be taken are where significant hardware changes would be required to upgrade the plant to STS requirements. This submittal has been in draft form and was to be submitted in November 1985. However, at the resident inspectors' exit on January 14, 1986, the licensee stated that the submittal of the TS revisions would be delayed until 1987.

   b. Previously Identified Items

      (Closed) Unresolved Item (UNR) 250,251/85-24-04. This unresolved item addressed the advisability of operating the plant in hot standby without the cold leg accumulators in service. The licensee has periodically heated both units to normal operating temperature and pressure with the accumulators inoperable because such action is not forbidden by TS 3.4.1.a. However, after careful review of the FSAR it was determined that the FSAR does not contain an evaluation of a loss of coolant accident (LOCA) originating while the plant is shutdown and the accumulators are unavailable. An evaluation by the NRC staff concluded that with the accumulators unavailable, the consequences of both a large and small break LOCA might be unacceptable due to the decay heat generated by the fuel. The NRC evaluation concluded that operating with the accumulators isolated was inconsistent with the design basis as documented in the FSAR but did not violate TS 3.4.1.a because that TS addressed only requirements to be met prior to criticality as opposed to prior to heatup and pressurization.

The failure to have adequate procedures to operate the plant in accordance with the design basis as described in the FSAR is a violation that occurred due to inadequate procedural guidance contained in OP 0202.1, Reactor Startup - Cold Condition to Hot Standby Condition. This violation is further discussed in paragraph 7. The licensee's corrective action for this discrepancy will be tracked under violation number 250,251/85-44-01.

4. IE Information Notice (IEIN) Followup (92717)

(Open) IEIN 85-94, Potential for Loss of Minimum Flow Paths Leading to ECCS Pump Damage During a LOCA. The licensee agreed to explore the implications of the IEIN on an expedited basis and found that the potential for a loss of recirculation flow existed. The loss of one fail-closed air operated valve could affect two high head safety injection (HHSI) pumps and the loss of non-safety grade instrument air would close all four recirculation valves and block both recirculation paths with each affecting two HHSI pumps.

The plant requested engineering to evaluate long term solutions and issued procedural changes and a training brief. The training brief covered the site's actions, which included the addition of a caution to the emergency operating procedures. This caution stated that, if the reactor coolant system pressure remained above the HHSI pump shutoff head while the pumps were running, to verify that the recirculation path valves were open.

5. Monthly and Annual Surveillance Observation (61726/61700)

The inspectors observed TS required surveillance testing and verified: that the test procedure conformed to the requirements of the TS, that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation (LCOs) were met, that test results met acceptance criteria requirements and were reviewed by personnel other than the individual directing the test, that deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel and that system restoration was adequate. For completed tests, the inspectors verified that testing frequencies were met and tests were performed by qualified individuals.

The inspectors witnessed/reviewed portions of the following test activities:

Units 3 and 4 Auxiliary Feedwater (AFW) Train 1 Operability Verification
Units 3 and 4 AFW Train 2 Operability Verification
Unit 4 Containment Spray Pump Testing
Unit 3 Reactor Protection System Periodic Test
Units 3 and 4 AFW Nitrogen System Testing

No violations or deviations were identified.

6. Maintenance Observations (62703/62700)

Station maintenance activities concerning safety-related systems and components were observed and reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards and in conformance with the TS.

The following items were considered during this review, as appropriate: that LCOs were met while components or systems were removed from service; that approvals were obtained prior to initiating work; that activities were accomplished using approved procedures and were inspected as applicable; that procedures used were adequate to control the activity; that troubleshooting activities were controlled and repair records accurately reflected what took place; that functional testing and/or calibrations were performed prior to returning components or systems to service; that QC records were maintained; that activities were accomplished by qualified personnel; that parts and materials used were properly certified; that radiological controls were properly implemented; that QC hold points were established and observed where required; that fire prevention controls were implemented; that outside contractor force activities were controlled in accordance with the approved QA program; and that housekeeping was actively pursued.

The following maintenance activities were observed and/or reviewed:

Repair of the AFW turbine steam admission stop check valves
Repair of Unit 4 Rod Control Cluster Assembly (RCCA) M-6 and Unit 3 RCCA N-9
Repair of the "B" EDG Day Tank Level Switch

On December 19, 1985, during a routine tour of the EDG building, the inspector found two level switches (LS) on the "B" EDG day tank isolated. The switches, LS 1562B and LS 1554B, were isolated from the tank by their upper and lower instrument root valves. The switches were not known to be inoperable by the licensee.

LS 1554B is designed to sense day tank low level and alarm, via a remote control room annunciator, if the level falls below the level setpoint. LS 1562B is designed to sense day tank low level and provide an input to the "B" fuel oil transfer pump automatic start circuit should the setpoint level be reached.

The licensee, when informed of the discrepancy, took prompt action to restore the level switches to service. When LS 1554B was unisolated, the tank low level alarm was received in the control room. The indicated tank level was 4 feet 11 inches by local sight glass. The tank contained approximately 2000 gallons of fuel oil; tank capacity is approximately 4000 gallons.

During the time that the level switches were isolated, the control room tank low level annunciator was incapable of alarming and the "B" fuel oil transfer pump was not capable of automatic day tank refill.

After reviewing maintenance records, the licensee determined that the level switches were probably inadvertently isolated during maintenance on a similar, adjacent level switch (LS 1561B). This switch provides an input to the "B" fuel oil transfer pump automatic stop circuit upon receipt of a day tank high level signal. On November 19, 1985, the transfer pump failed to automatically shut off when the high level setpoint was reached. As a result, the "B" day tank overflowed.

Between November 19 and December 10, 1985, the main root valves for the level switches were isolated for troubleshooting and repair of LS 1561B. Repairs were delayed due to the unavailability of parts. Isolation of the root valves removed all level switches and the local sight glass from service by isolating the switches from the tank upstream of the instrument isolation valves. During this time, the "B" fuel oil transfer pump was logged as out-of-service.

On December 10, 1985, LS 1561B was repaired; the clearance tags were removed, the root valves were opened and independently verified to be open. Apparently, the instrument isolation valves for LS 1554B and LS 1562B were not noticed to have been inadvertently closed during the original troubleshooting efforts. Consequently, they were not checked open during system restoration. All valves are located in close proximity to each other and the valves and level switches are virtually identical in appearance.

TS 6.8.1 requires that written procedures and administrative policies be established, implemented and maintained that meet or exceed the requirements and recommendations of sections 5.1 and 5.3 of ANSI N18.7-1972 and Appendix A of USNRC Regulatory Guide 1.33.

ANSI N18.7-1972, section 5.3.(3), Post-Maintenance Checkout and Return to Service, requires that instructions be included in maintenance procedures for returning equipment to its normal operating status. It further states that operations personnel shall place the equipment in service and verify and document its functional acceptability. Special attention shall be given to restoration of normal conditions, such as removal of signals used in maintenance or testing, and to systems that can be defeated by leaving valves or breakers mispositioned.

Contrary to the above, during the performance of maintenance repairs on the "B" EDG day tank level switch (LS 1561B), using maintenance work orders 63-8224 and 69-4437, instructions were not included or referenced in the work orders regarding restoration of valves to their normal positions. Consequently, on December 10, 1985, two level switches, located adjacent to the work area, were not returned to service because their isolation valves were inadvertently left shut. This disabled both the remote day tank low level alarm and the automatic start capability of the "B" fuel oil transfer pump.

The failure to include adequate guidance in maintenance instructions governing the restoration of equipment to service following repair is a violation (250,251/85-44-01). This item constitutes an additional example of the failure to meet the requirements of TS 6.8.1 which is discussed in paragraph 7.

During an independent evaluation of this occurrence, the following additional discrepancies were noted:

a. The clearance which was hung on November 19, 1985, was not revised following localization and identification of the failed level switch. Consequently, between November 19 and December 10, 1985, the main root valves were shut - causing the tank high level LS, low level LS, and level sight glass to be unnecessarily out of service. If LS 1561B were isolated at its instrument valves the other equipment would have remained operable. The tagout that existed for approximately three weeks precluded accurate observation of the tank's level.

b. The tank curve book, a controlled document located in the control room, does not have a curve for the EDG day tanks. Consequently, it is not possible to determine that the tank holds 2000 gallons as required by prerequisite 3.4 of procedure 0-OP-023, Emergency Diesel Generator.

c. Each Nuclear Plant Operator (NPO) logs the level in the day tank sight glass once a day. However, the NPOs have not been provided with acceptance criteria for the sight glass level. Consequently, on December 19, 1985, at approximately 1:00 a.m., the NPOs logged the tank level reading as 4 feet 11 inches and did not realize that the level in the tank was below the low level setpoint.

d. Although the NPOs logged the sight glass level daily between December 10 and 19, they did not notice that the level switches located next to the sight glass were isolated.

e. Sections 5.3 and 5.4 of procedure 0-OP-023 direct the EDG operator to verify that the skid tank and day tank levels are being maintained but does not provide acceptance criteria.

f. Sections 7.1.2 and 7.2.2 of 0-OP-023 require that the tank level be maintained between 7 feet 9 inches and 9 feet 2 inches. However, the top of the tank by local sight glass is approximately 7 feet 0 inches. The frame of reference for the procedurally specified levels is unknown.

g. The diesel fuel oil storage tank outlet to the transfer pumps was not a locked open valve. Inadvertent shutting of the valve would prevent filling either day tank and could damage the transfer pumps. The licensee locked this valve open when informed of the discrepancy.

h. OP 4304.1, Emergency Diesel Generator - Periodic Test Load on 4KV Bus, requires, in section 8.27, that the fuel oil transfer pump be started and that the level in the day tank be observed to increase. The actual level in the day tank is not recorded and the desired level to establish is not specified. Consequently, during the performance of the procedure on November 18, 1985, the level in the tank was raised but not above the low level alarm setpoint prior to securing the pump.

i. The automatic start capability of the fuel oil transfer pumps, a feature described in section 8.2 of the FSAR, is never tested to verify operability. The licensee identified this discrepancy in November, 1984 (L-84-265) and has not yet implemented a surveillance. Implementation dates have been repeatedly extended by the licensee. The original due date was June 1, 1985; this was first extended until October 15, 1985 and then again until November 22, 1985. The November date was later extended until December 18, 1985 and this date was extended to January 17, 1986. The licensee has decided to incorporate the surveillance into a procedure different from the one originally planned and is projecting an additional two-week delay in final implementation. Licensee commitment number 84-1308-34 refers.

j. The clearance for the tagout of the level switches did not reference the valve numbers for the isolation root valves. The clearance was written without reference to the valve numbers because no drawing of the diesel fuel oil system is available in the control room for ready reference.

The continued evaluation of items (a) through (j) is an Inspector Followup Item (250,251/85-44-02).

7. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers and confirmed operability of instrumentation. The inspectors verified the operability of selected emergency systems, verified that maintenance work orders had been submitted as required and that followup and prioritization of work was accomplished. The inspectors reviewed tagout records, verified compliance with TS LCOs and verified the return to service of affected components.

By observation and direct interviews, verification was made that the physical security plan was being implemented.

Plant housekeeping/cleanliness conditions and implementation of radiological controls were observed.

Tours of the intake structure and diesel, auxiliary, control and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks and excessive vibrations.

The inspectors walked down accessible portions of the following safety-related systems on Unit 3 and Unit 4 to verify operability and proper valve/switch alignment:

Emergency Diesel Generators
Auxiliary Feedwater
4160 volt and 480 volt switchgear
Containment Spray

a. Between June 23 and June 26, 1985, Unit 3 was maintained at hot shutdown with all three cold leg accumulators out of service. TS 3.4.1.a states that the reactor shall not be made critical, except for low power physics tests, unless each accumulator is pressurized to at least 600 psig and contains 875 to 891 cubic feet of water with a boron concentration of at least 1950 ppm and is not isolated.

While TS 3.4.1.a clearly prevents a reactor from being made critical, except for physics tests, without the accumulators in service, it does not specifically address the permissibility of taking a plant from cold shutdown to hot shutdown with the accumulators inoperable. Additionally, it does not address the permissibility of isolating the accumulators prior to cooling down following power operation.

TS 3.4.1.b provides an LCO on loss of accumulator operability but the TS only applies to reactors which are operating at power - not to reactors which are subcritical.

The lack of guidance in TS 3.4.1.a relative to accumulator operability was discussed in Inspection Report 250,251/85-24. UNR 250,251/85-24-04 was opened pending an NRC evaluation of the intent of the TS.

b. In November 1985, the inspectors reviewed the licensee's progress in resolving this issue. The licensee was not pursuing the matter and considered the evaluation to be the responsibility of the NRC. At the request of the NRC, the licensee added the item to its commitment tracking system and assigned a staff member to pursue the matter.

The NRC evaluation, though preliminary at the time, was summarized in Inspection Report 250,251/85-37 which was issued on December 9, 1985. That report contains the following statement:

> The accumulators are designed to refill the reactor vessel following a LOCA. The FSAR for Turkey Point does not contain an evaluation of the consequences of a LOCA with the accumulators unavailable. Consequently, it is not apparent that excessive fuel temperatures would be avoided in the event such an accident were to occur. This is especially true if the accumulators were unavailable (due to low pressure, low water level or isolation valve closure) following a reactor trip and a LOCA. This worst case event would involve the maximum possible reactor fuel decay heat load.

The NRC evaluation of this matter was completed on December 24, 1985. The evaluation concluded that UNR 250,251/85-24-04 documented a means by which the Turkey Point plant could be operated in a condition inconsistent with the Units 3 and 4 design bases without violating the TS.

c. It is the position of the NRC Division of Licensing that the licensee has an indisputable obligation to operate the plant in a manner fully consistent with the FSAR design basis, even in light of ambiguous or incomplete TS. In this instance the TS do not attempt to address the many assumptions contained in the FSAR relative to operating the engineered safety features. As a result, the TS do not address the requirements to be met while preparing for reactor startup, including heatup and pressurization of the primary coolant. Rather than require the licensee to supplement the TS, such that they address thousands of FSAR assumptions, the NRC expects the licensee to use administrative controls to preclude operating outside the FSAR design basis.

The licensee felt that TS 3.4.1.a only required operable accumulators immediately prior to criticality. The licensee erroneously assumed that, since the status of the accumulators during preparation for startup was not addressed by the TS, the accumulators had no significant function to serve until after the reactor was critical.

The resident inspectors discussed this reasoning with the licensee in July 1985. Specifically discussed was TS 3.4.1.b, which requires that a unit operating at power be placed in cold shutdown during a sustained loss of one accumulator or the simultaneous loss of two or more accumulators. The point was made that TS 3.4.1.b does not allow a unit which was operating at power at the time the accumulators were lost to remain at normal operating temperature and pressure. The licensee maintained that no inference could be obtained from TS 3.4.1.b that applied to units undergoing heatup because that TS was limited to power operation. If this were true, then there would be a conflict between TS 3.4.1.b, which requires shutdown and cooldown on loss of accumulators and TS 3.4.1.a, which, according to the licensee allows heatup without operable accumulators.

d. In the absence of an explicit TS, the licensee is expected to have reviewed the system description and the assumptions for accident analysis found in the FSAR. Since the Turkey Point FSAR assumes that at least two accumulators are available for any LOCA and since the effect of a LOCA on a shutdown plant has not been analyzed, it follows that the plant's response to a LOCA while shutdown without accumulators is not known. Consequently, there is no basis for the licensee's assumption that the accumulators serve no subcritical protective function. (Newer pressurized water reactors have an analysis that concludes the accumulators are not needed for core protection for a LOCA which initiates below 1000 psig. The Turkey Point plant, though not specifically analyzed for a low pressure LOCA, would not be expected to respond differently.)

In this instance, the licensee's procedural controls were not adequate to prevent straying from design basis assumptions. Specifically, OP 0202.1 requires that the accumulator isolation valves be locked open when the primary coolant pressure reaches 1000 psig. However, section 8.34 of the procedure states only that the accumulators "should" be filled and pressurized prior to reaching 1000 psig. Plant procedures specify that "should" is used to denote the non-mandatory nature of a procedural step. Mandatory procedural steps generally specify that the step in question "Shall" be accomplished.

e. TS 6.8.1 requires that written procedures and administrative policies be established, implemented and maintained that meet or exceed the requirements and recommendations of sections 5.1 and 5.3 of ANSI N18.7-1972 and Appendix A of USNRC Regulatory Guide 1.33.

Appendix A of USNRC Regulatory Guide 1.33 recommends that written procedures be established covering the startup, operation and shutdown of the ECCS. The cold leg accumulators are a portion of the ECCS.

The FSAR does not consider the consequences of a LOCA when the cold leg accumulators are unavailable.

Contrary to the above, OP 0202.1 was not adequate, in that it allowed the units to be operated at full temperature and pressure without the cold leg accumulators in service, that is, to be operated in an unanalyzed configuration without regard for the possibility that an accident of a different type than any previously identified in the FSAR could occur. Between June 23 and June 26, 1985, the Unit 3 reactor was operated at full temperature and pressure (hot standby condition) while all three accumulators were empty and depressurized. On several additional occasions, the licensee has failed to maintain the required level and pressure in the accumulators with the units in hot standby.

The failure to establish adequate procedures governing the startup, shutdown and operation of the emergency core cooling system is one example of a failure to meet the requirements of TS 6.8.1 and is a violation (250,251/85-44-01). An additional example of this violation is discussed in paragraph 6.

8. Engineered Safety Features Walkdown (71710)

The inspector verified operability of the Emergency AC Electrical Distribution system for Units 3 and 4, by performing a complete walkdown of the accessible portion of the system. The following specifics were reviewed and/or observed as appropriate:

a. that the licensee's system lineup procedures matched plant drawings and the as-built configuration;

b. that the equipment conditions were satisfactory and items that might degrade performance were identified and evaluated (e.g. hangers and supports were operable, housekeeping was adequate, etc.);

c. that instrumentation was properly valved-in and functioning and that calibration dates were not exceeded;

d. that valves were in proper position and were locked/lockwired as required;

e. that breaker alignment was correct and power was available;

f. that local and remote position indications were functional and in agreement; and

g. that breakers and instrumentation cabinets were free of damage and interference.

No violations or deviations were identified.

9. Plant Events (93702)

An independent review was conducted of the following events:

On December 15, 1985, the potential for overloading the EDGs was reported. The immediate corrective action of changing the procedure to specify a maximum ampere loading for the EDGs was verified. The further engineering studies will be followed.

On December 27, 1985, the Unit 4 backup group "A" pressurizer heater power supply breaker could not be opened from the control room and the disconnect circuitry to prevent EDG overloading would not function. The condition could not be duplicated; the heaters were kept inoperable and the heater supply breaker was replaced several days later.

On December 30, 1985, the Unit 3 turbine received a runback signal from an individual rod position indicator (IRPI) on rod N-9. The operators and the unit responded properly and the runback was terminated with the unit stabilized at 30 percent power. The IRPI was determined to be malfunctioning and the rod position was verified on a continuing basis.

On January 2, 1986, an unplanned start of the AFW pumps was initiated. A test of the AFW nitrogen system was being conducted with the AFW turbine steam admission stop check valves (SCV) from Unit 4 steam generators closed. One of the SCVs had suffered in internal failure, thereby admitting steam to the AFW turbine; the valve was declared inoperable. The Unit 3 AFW stop check valves were radiographed the following day and the licensee made the determination that they were operable. Further inspection was conducted by an NRC Region II inspector and the details will be discussed in Inspection Report 250,251/86-02.

On January 5 and 6, 1986, Unit 4 experienced turbine runbacks due to rod M-6 dropping. The first runback occurred from 100 percent power and the second from 49 percent power. The operators and the unit responded properly; the plant was stabilized at a reduced power level. When the unit shut down for refueling on January 10, the rod drive mechanism was found faulty.

On January 7, 1986, Unit 3 had two trains of AFW inoperable and Unit 4 had one train of AFW inoperable and the TS action statements were entered. The inoperable conditions were caused by two AFW SCVs on Unit 3 and one SCV on Unit 4 being declared inoperable when the radiographs from January 3 were re-read. Unit 3 was shut down on January 7 and Unit 4 on January 10. These events are described in Inspection Report 250,251/86-02.

On January 10, 1986, the 3A 4160 volt bus was de-energized when a worker bumped a relay. Unit 3 was at cold shutdown and Unit 4 remained at 100 percent power. The "A" EDG started but did not load onto the bus due to the lockout signal.

No violations or deviations were identified.

10. Independent Inspection

During the report period, the inspectors routinely attended meetings with licensee management and monitored shift turnovers between shift supervisors, shift foremen and licensed operators. These meetings included daily discussions of plant operating and testing activities as well as discussions of significant problems or incidents. As a result, the inspectors reviewed potential problem areas to independently assess their importance to safety, the adequacy of proposed solutions, any improvement and progress, and the adequacy of corrective actions. The inspectors' reviews of these matters were not limited to the defined inspection program. Independent inspection efforts were conducted in the following areas.

On January 10, 1986, the inspector, Region II and the licensee agreed on the course of action to repair the Unit 3 AFW SCVs and to search for the valve parts which had been missing since December 1985. The licensee sent Region II a letter (L-86-10, dated January 10, 1986) to document this commitment. On January 12, the inspector and Region II discussed the licensee's analysis of the cause of the valve failures. The inspector later reviewed the details of the analysis and found it to be based on sound engineering principles. The missing SCV guide studs and many weld-preparation metal shavings were found at the AFW turbine steam admission strainers. The licensee sent Region II a letter (L-86-11, dated January 13, 1986) which documented the actions, the findings and the analyses.

No violations or deviations were identified.