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

Report Nos.: 50-250/85-24 and 50-251/85-24

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

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

Facility Name: Turkey Point 3 and 4

Inspection Conducted: June 10 - July 8, 1985

Inspectors: Gregory A. Pick for — July 29 1985
T. A. Peebles, Senior Resident Inspector — Date Signed

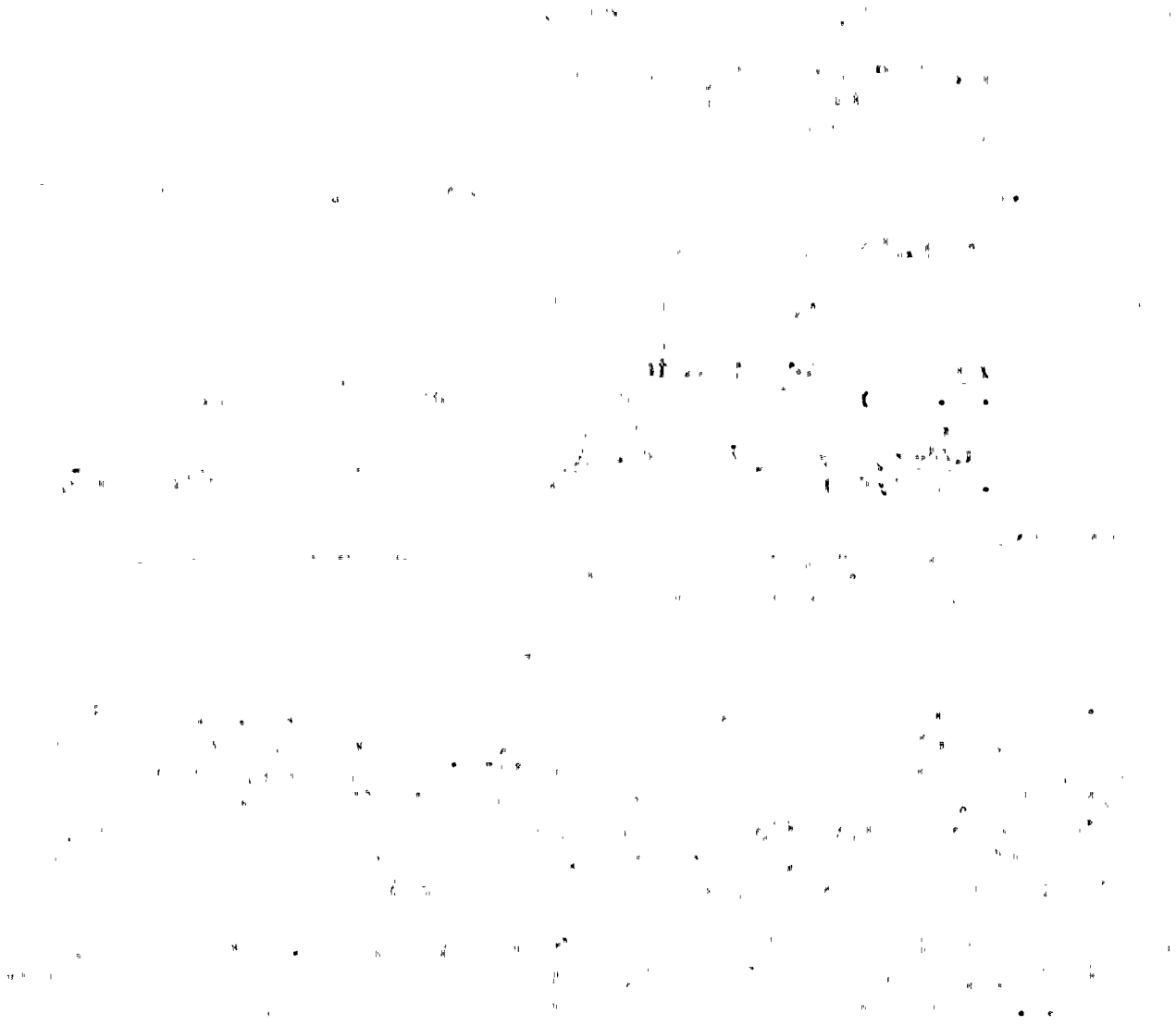
Gregory A. Pick for — July 29, 1985
D. R. Brewer, Resident Inspector — Date Signed

Approved by: Stephen A. Elrod — July 25, 1985
Stephen A. Elrod, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed 211 direct inspection hours at the site, including 56 hours of backshift, in the areas of licensee action on previous inspection findings, followup on TMI implementation, licensee event reports (LER), Inspection and Enforcement Bulletin (IEB) followup, annual/monthly/refueling surveillance, maintenance observations and reviews, operational/refueling startup safety verification, engineered safety features (ESF) walkdown, plant events and independent inspection.

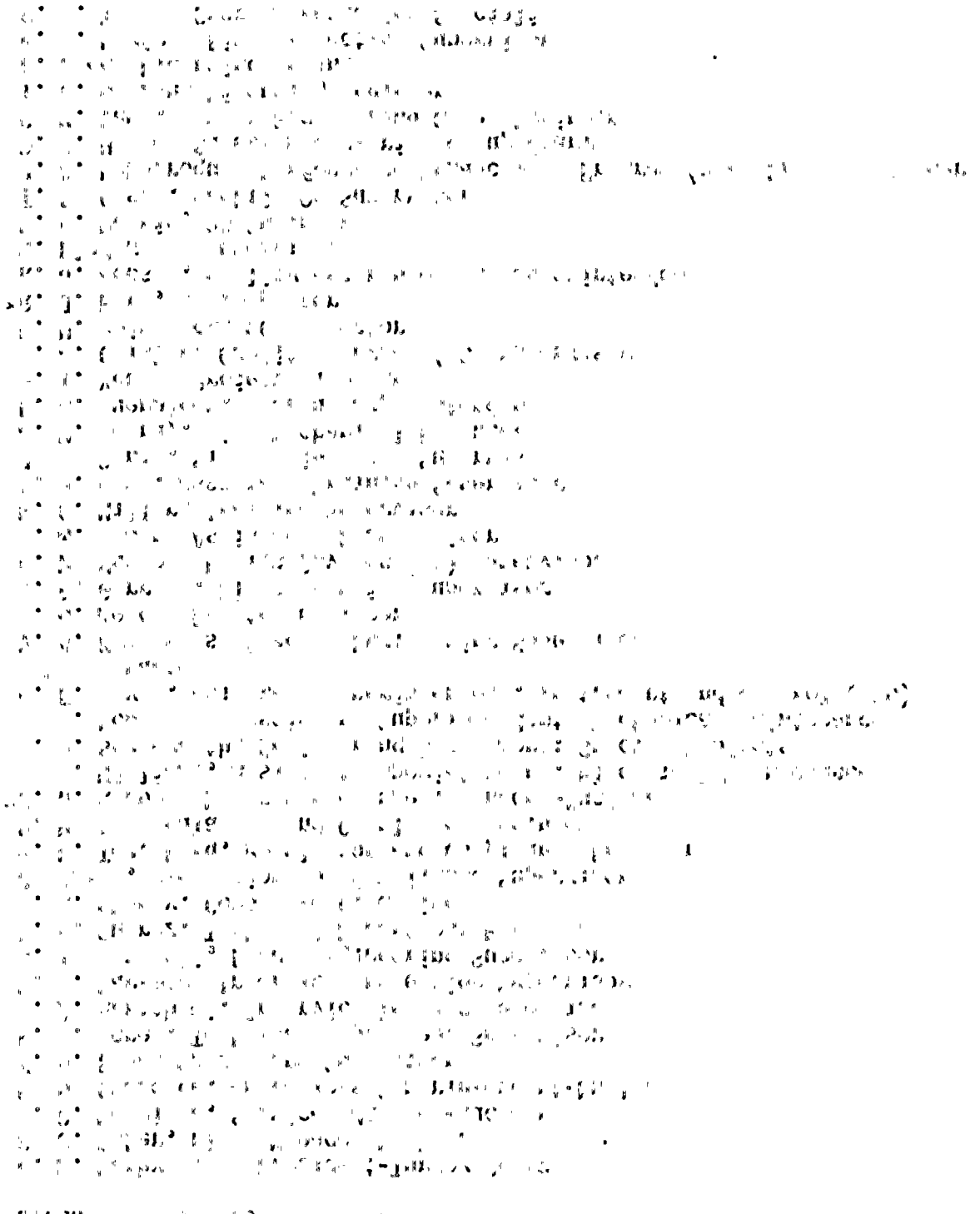
Results: Violations - Failure to meet the requirements of Technical Specification (TS) 3.5, Table 3.5-2, Item 1.5; failure to implement procedures as required by TS 6.8.1; and failure to meet the requirements of TS 4.1., Table 4.1-2, Item 10.



REPORT DETAILS

1. Licensee Employees Contacted

C. M. Wethy, Vice President-Turkey Point
*C. J. Baker, Plant Manager-Nuclear
J. P. Mendieta, Services Manager-Nuclear
D. D. Grandage, Operations Superintendent-Nuclear
T. A. Finn, Operations Supervisor
K. L. Jones, Technical Department Supervisor
*B. A. Abrishami, Inservice Testing Supervisor
H. E. Hartman, Inservice Inspection Supervisor
D. Tomaszewski, Plant Engineering Supervisor
E. A. Suarez, Technical Department Engineer
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
W. R. Williams, Assistant Superintendent, Electrical Maintenance
F. H. Southworth, Engineering Department; Special Projects
R. A. Longtemps, Assistant Superintendent, Mechanical Maintenance
E. F. Hayes, Asisstant Superintendent, Instrument and Control (I&C) Maintenance
*V. A. Kaminskas, Reactor Engineering Supervisor
R. G. Mende, Reactor Engineer
R. E. Garrett, Plant Security Supervisor
P. W. Hughes, Health Physics (HP) Supervisor
R. M. Brown, Assistant HP Sueprvisor
*W. C. Miller, Training Supervisor
P. J. Baum, Assistant Training Supervisor
J. M. Donis, Site Engineering Supervisor
J. M. Mobray, Site Mechanical Engineer
*L. C. Huenniger, Startup Superintendent
H. T. Young, Project Site Manager
M. J. Crisler, Quality Control (QC) Supervisor
R. H. Reinhardt, QC Inspector
*R. J. Earl, QC Inspector
R. J. Acosta, Quality Assurance (QA) Superintendent
*W. Bladow, QA Supervisor
L. E. Norris, QA Engineer
T. P. Coste, Backfit QA Supervisor
J. A. Labarroque, Performance Enhancement Program (PEP) Program Manager
D. W. Hasse, Safety Engineering Group Chariman
*G. M. Vaux, Safety Engineering Group Engineer
T. C. Grozan, Licensing Engineer
P. Pace, Licensing Engineer
B. C. LaPira, Fire Protection Supervisor
C. D. Tyson, System Protection Specialist



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.

The exit meeting was held on July 5, 1985, with the persons noted in paragraph 1. The areas requiring management attention were reviewed.

The three items identified as violations were:

Failure to meet the requirements of TS 3.5, Table 3.5-2, Item 1.5, in that the high steamline flow in conjunction with low average temperature safety injection (SI) signal was blocked at a time when it was required to be operable (paragraph 11), (251/85-24-01).

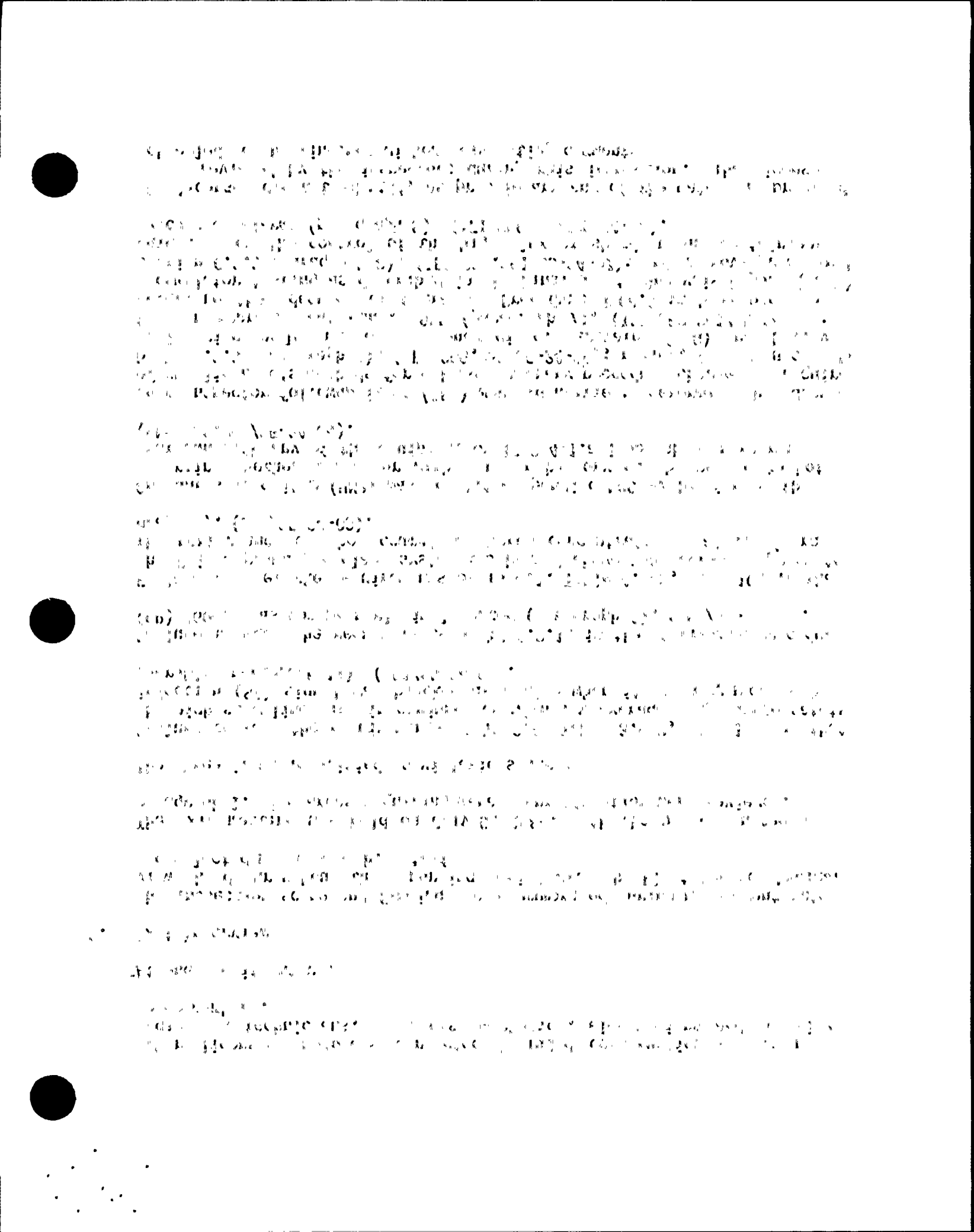
Failure to meet the requirements of TS 6.8.1, in that Operating Procedure (OP) 1604.8 was not properly implemented (paragraph 6), (250/85-24-02).

Failure to meet the requirements of TS 4.1, Table 4.1-2, Item 10, in that the Unit 3 primary coolant system was heated above 200 degrees F prior to the performance of the accumulator boron concentration analysis (paragraph 8), (250/85-24-03).

One unresolved item (UNR) was identified pending NRC evaluation of the TS: determine whether a reactor with a power history can be heated to hot shutdown with any of the equipment of TS 3.4.1.a inoperable (paragraph 11), (UNR 250,251/85-24-04).

Four inspector followup items (IFI) were identified: determine the adequacy of the licensee's methods for making temporary procedure changes as required by TS 6.8.3 (paragraph 8), (IFI 250,251/85-24-05); review, for adequacy, the engineering evaluation of emergency diesel generator (EDG) operability between February and June, 1985 (paragraph 7), (IFI 250,251/85-24-06); determine the adequacy of Operating Procedure 4504.1 with respect to accumulator testing as described in the Final Safety Analysis Report (FSAR) section 6.2.3 (paragraph 8), (IFI 250,251/85-24-07); and improve procedural guidance for the control of the high flux at shutdown and containment evacuation alarms (paragraph 8), (IFI 250,251/85-24-08).

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 findings without dissenting comments.



3. Licensee Action on Previous Enforcement Matters

a. Monthly update of Performance Enhancement Program

The PEP was reviewed to determine if commitments were being met. Status was discussed with the PEP Manager and with other members of management.

The facility upgrade project has continued. Concrete is being poured for support columns for the new administrative building, with the third floor beginning to be poured. The schedule for completion of the building including the third floor is the end of December 1985, but occupancy is scheduled for March 1986. The new health physics building is almost complete with the paving around the building to be done and the fencing to be moved. Move-in is scheduled for July 1985, after the current Unit 3 outage. The maintenance building has been scoped and the tentative schedule is for completion in 18 months.

The schedule for the PEP continues to be met within acceptable limits, and all modifications have been cleared by the Region.

b. Previous Inspection Findings

(Closed) Violation 250/83-24-01 Failure to Retain a QA Records Completed Procedure. The procedures have been changed to require that they be kept as QA records. The licensee has a program that requires new procedures to be reviewed to determine which procedures will be QA records.

(Closed) IFI 250,251/83-24-03 Turkey Point Procedure Review Project. This IFI was to follow the implementation of the Turkey Point Procedure Review Project which was draft planned in June of 1983. However, this IFI will now be followed as part of the formalized PEP.

(Closed) Violation 250,251/83-32-01 Requisition for Packing. Packing for motor operated valves (MOV)-535 and MOV-536 was improper and maintenance on the valves was improper. This was caused by maintenance failing to provide a sufficient description so that the Grafoil Dieformed Packing could be properly ordered and properly installed. The valves are the block valves for the pressurizer power operated relief valves. The maintenance personnel were trained in the proper installation techniques and the ordering information was upgraded.

(Closed) IFI 250,251/83-32-02 Open Fire Barriers. 10 CFR 50, Appendix R work is progressing and the fire barriers have been evaluated and are being constructed. Fire watches are continuously patrolling until the work is completed.

(Closed) Violation 250,251/83-26-01 Inadequate Procedural Coverage of Shutdown Rod Movement. Shutdown bank rod withdrawal criteria and related steps were added to the appropriate operating procedures OP 0202.1, OP 0202.2, OPO-204.3 and OP 0205.2.

(Closed) Violation 250,251/83-26-02 Failure to Include Emergency Procedure (EP) 20005, Control Room Inaccessibility, in list of procedures affected by plant change modification (PCM) 80-117, Auxiliary Feedwater System Redundant Suction/Discharge Lines. The procedure was revised and a PCM coordinator has been assigned, assuring that appropriate documents are revised as part of the close out of PCMs.

(Closed) IFI 250,251/83-26-04 Change OP 205.2 to place source range instruments in bypass prior to pulling the instrument fuses. The procedure was revised.

(Closed) IFI 250/85-02-05 A safety-related safety relief valve program will be set up and all safety-related relief valves which have not been tested within five years will be tested during the 1985 Unit 3 outage. The safety relief valves were tested during the outage.

4. Followup on Post TMI Implementation (NUREG 0737)

(Closed - both Units) Item II.E.1.1.2
Auxiliary Feedwater System Evaluation (Long Term)

(Closed - both Units) Item II.E.1.2
Auxiliary Feedwater System Automatic Initiation and Flow Indication

The requirement could be met by two flowrate indicators or one wide range steam generator level indicator.

The indication system should be: environmentally qualified, powered from a highly reliable, battery backed, non-Class 1E power source, periodically testable, part of the plant QA program, and capable of display on demand. The added displays and controls must be part of the human factors design. The installed system meets all of these requirements.

(Closed) The item listed as II.E.1.2 in the Commission's Order issued on March 14, 1983, and relating to Generic Letter 82-05 is also closed.

The following PCMs were installed.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible] system should [illegible]

[illegible]

[illegible]

Unit 3	Title	Completion date
PCM 80-35	AFW Line Support Modifications	10/80
PCM 80-55	Upgrade of AFW System Flow Control and Indications	10/82
PCM 80-77	Addition of Condensate Storage Tank Redundant Level and Alarm	2/82
PCM 80-78	Modification of AFW turbine Steam Supply Valves, Qualified	11/83
Unit 4		
PCM 80-36	AFW Line Support Modifications	9/81
PCM 80-56	Upgrade of AFW System Flow Control and Indications	6/82
PCM 80-71	Addition of Condensate Storage Tank Redundant Level and Alarm	4/82
PCM 80-79	Modification of AFW Turbine Steam Supply Valves, Qualified	12/84
Both Units		
PCM 80-105	AFW Pump Turbine Modifications	10/83
PCM 80-117	Upgrade AFW Suction, Discharge and Steam Supply Piping	12/83

The current status of the systems and components affected by the above PCMs have been inspected to verify proper implementation.

The items listed below are closed for both units. They relate to the TMI items addressed in IE Inspection Report 250,251/83-05.

Condensate storage tank redundant level indication	complete
Steam supply valves (replace 2 of 3 ac to dc)	complete
Lube oil cooler modifications	complete
Automatic flow control	complete
Redundent steam and feedwater piping	complete
Removal of non-seismic piping from suction	complete
Demineralized water tie-ins to Unit 4	complete
Installation of high pressure turbine casings	complete

No violations or deviations were identified.

5. Licensee Event Report Followup (92700)

The following LER was reviewed and closed. The inspector verified that: reporting requirements were met; causes were identified; corrective actions appeared appropriate; generic applicability was considered; and the LER forms were complete. A more detailed review was then performed to verify that: the licensee had reviewed the event; corrective action had been

taken; no unreviewed safety questions were involved; and violation of regulations or TS conditions had been identified.

(Closed) LER 250/83-21 On November 29, 1983, while performing a replacement of three auxiliary feedwater steam supply stop check valves, a four inch pipe section between the main steam line from A steam generator to valve 3-119 and a four inch pipe section between the B main steam line and valve 3-219 were found to be schedule 40 piping instead of schedule 80. This piping was replaced with schedule 80 pipe. Ultrasonic testing of the equivalent Unit 4 sections of piping identified a section of schedule 40 piping between the A main steam line and valve 4-119. This piping was replaced with schedule 80 pipe in conjunction with the check valve replacement under PCM 82-312 in March 1984.

6. Monthly and Annual Surveillance Observation (61726/61700)
Plant Start-up from Refueling (71711)

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 (LCO) 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 those identified during the test were properly reviewed and resolved by management personnel, and that system restoration was adequate. For completed tests, the inspector verified that testing frequencies were met and tests were performed by qualified individuals.

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

Hot and cold control rod drop time testing (OP 1604.8)
Reactor protection system periodic test (OP 1004.2)
Reactor coolant system overpressure testing (OP 1004.1)
Reactor trip breaker testing (MP 0707.10)
Emergency diesel generator periodic test (OP 4304.1)
Engineered safeguards and emergency power systems integrated test (OP 4104.2)
Nuclear instrumentation system (NIS) runback change

On June 25, 1985, control rod drop time testing was observed in accordance with OP 1604.8, dated April 16, 1984, Control Rod Drive Mechanism/Rod Position Indication (CRDM/RPI) Stepping and Drop Time Test. This test provides instructions for performing the rod control cluster stepping test, the rod drop time test and the rod position indication system calibration. The rod drop time test is required by TS Table 4.1-2, item 5 and is performed every 18 months and following each removal of the reactor vessel head.

During the performance of the procedure it was noted that the rod drop time measurements were not being made in the manner required by the procedure. The procedure requires that the time measurement be made beginning when the stationary gripper voltage is removed and ending when the control rod first reaches the bottom of the core. The correct method of making the measurement is pictorially displayed in Figure 1, page 16, of the procedure and is labeled Sample Rod Drop Trace. The technician performing the procedure began the measurement when the rod position indication signal began to change. This typically occurs approximately 0.05 seconds after the stationary gripper voltage is removed. The technician continued the measurement until the control rod stabilized on the bottom of the core instead of stopping when the rod first reached the core bottom. All rods in shutdown bank A had incorrect control rod drop times recorded on the data sheet. The measurement errors were promptly corrected when identified. The timing errors were small and were in a conservative direction since the time included for the control rod to stabilize on the core bottom was in excess of the time lost in starting the measurement late.

The failure to properly implement control rod drop time measurements as required by OP 1604.8 is a violation of TS 6.8.1. This violation applies to Unit 3 only (250/85-24-02).

On June 22, 1985, while the unit was shutdown, the inspector witnessed the preoperational start-up testing for PCM 85-103 to modify the NIS runback logic from a one out of four to a two out of four coincidence. The testing on train A was complicated by dirt from concrete dust in the relay contacts. Plant conditions caused a train B runback signal to be locked in which placed power on the train B circuit. This delayed train B continuity testing until troubleshooting and procedure changes were accomplished. However, testing was completed satisfactorily.

7. Maintenance Observations (62703 & 62700)

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

The following items were considered during this review, as appropriate: LCO were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled, and the repair record accurately reflected what actually took place; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; QC

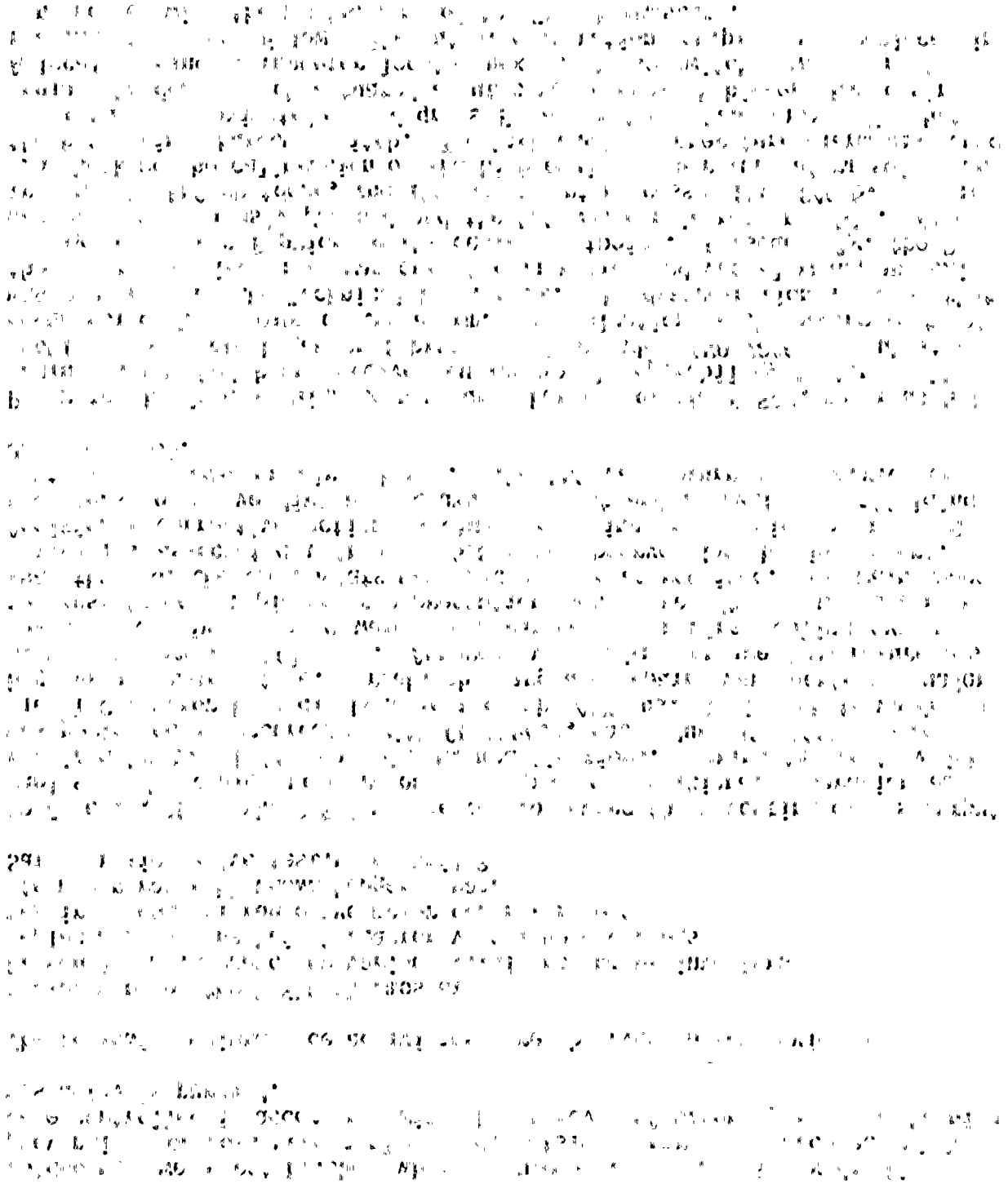
holdpoints were established where required and were observed; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

The following maintenance activities were observed and/or reviewed:

Replacement of the B EDG thermostats
Preventive maintenance on various vital instrument inverters
Replacement of the Unit 3 reactor vessel head o-rings
Repair of control rod drive motor generator sets
Steam generator blowdown hanger repair
Safety relief valve testing on Unit 3

On June 12, 1985, the B EDG was tested following the rerouting of its output cables. The cables were rerouted to provide additional separation as required by 10 CFR 50, Appendix R, modifications. During the test, which was performed in accordance with OP 4304.1, dated June 12, 1985, Emergency Diesel Generator Periodic Load Test on the 4KV Bus, the EDG shutdown due to high engine temperature. Troubleshooting and repairs were performed under plant work order (PWO) 2618. Apparently, the high engine temperature was due to excessive cooling water temperature. All nine cooling system thermostats were replaced as a precautionary measure after it was determined that three of the thermostats were not opening as required. The maintenance activities associated with PWO 2618 were observed by the inspectors. Additional corrective actions included cleaning the outside of the EDG radiators to remove dirt and accumulated dust and removal of scaffolding next to the radiator air exhaust. The EDG was returned to service on June 14, 1985.

Prior to the June 12 high temperature shutdown of the B EDG, numerous hot engine alarms had been received during weekly operability testing. The problem apparently began on February 7, 1985, when PWO 7846 was submitted documenting the receipt of the alarm. An evaluation of the engine test data was performed by the Technical Department. The determination was made that the EDG hot engine alarm was out of calibration and was alarming approximately 10 degrees F prior to the desired setpoint. Consequently, the PWO was not expeditiously pursued and the EDG was considered operable. After the June 12 EDG shutdown, the I&C Department processed PWO 7846 by removing and checking the calibration of the high engine temperature alarm switch and the hot engine shutdown switch. The high engine temperature alarm was found to actuate approximately 10 degrees F late rather than early. The hot engine shutdown switch actuated about seven degrees F higher than desired. A local reading thermometer located next to these switches was found to be reading 10 degrees F low. The out of calibration equipment was replaced in conjunction with the replacement of the EDG thermostats.



The licensee is currently evaluating these discrepancies to determine the status of the B EDG operability between February and June, 1985. The date when the evaluation will be complete is not yet known. However, the licensee plans to make the results available as soon as possible. Based on reviews of the maintenance efforts in June, the B EDG is operational. The review of the engineering evaluation concerning the operability of the B EDG is Inspector Followup Item (IFI 250,251/85-24-06).

On June 26, 1985, Unit 3 was returned to cold shutdown due to an unisolable leak of approximately two gallons per minute (gpm) through the reactor vessel o-rings. On July 1, 1985, the inspectors witnessed the videotaping of the inspection of the reactor vessel head o-rings and later reviewed the tape with the involved engineers. Initial determination was that no components were mispositioned which could have caused the leakage. The plan was to then clean up the general flange area and take detailed measurements to determine further action. The o-rings are not inspected for dimensional conformance with the purchase documents onsite, and the licensee is investigating where and how to accomplish this. The reactor vessel was designed by Babcock and Wilcox (B&W) and the licensee's investigation has revealed that B&W has made changes to the o-ring design on other B&W reactor vessel designs to enhance the sealing characteristics of the o-rings.

On July 1, 1985, the inspector toured the containment and observed three pipe hangers on B steam generator blowdown piping which the licensee had identified needing repair. One mechanical snubber was broken; one baseplate had pulled the concrete anchor bolts free; and one baseplate had pulled the steel concrete imbedment loose. The engineering staff is evaluating the repairs required.

During the Unit 3 outage, the licensee tested all of the safety relief valves on the unit which had not been tested within the last five years. These relief valves are now in a five year testing schedule. Testing revealed that most relief valves opened at approximately the proper setting but then seat leakage became excessive and the excessive leakage caused the valve seat to require rework.

During the upcoming Unit 4 outage, all safety-related safety relief valves which have not been tested in the last five years will be tested then.

No violations or deviations were identified.

8. Operational Safety Verification (71707)
Plant Start-up from Refueling (71711)

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, reviewed tagout records, verified compliance with

TS limiting conditions for operation 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 Pumps
Component Cooling Water
4160 Volt and 480 Volt Switchgear
Radiological Waste Building
Control Room Vertical Panels
Nuclear Instrumentation Drawers
High Head Safety Injection
Containment Spray System
120 Vac Inverters
Unit 3 Containment Prior to Start-Up

a. The inspectors observed portions of the Unit 3 plant heatup in accordance with OP 0202.1, dated April 12, 1985, Reactor Startup - Cold Condition to Hot Shutdown Conditions. Section 8.12 of the procedure requires numerous items to be completed prior to the reactor coolant temperature exceeding 200 degrees F. Item 8.12.13 requires that the boron concentration in each accumulator be verified to be at least 1950 parts per million (ppm). On June 22, 1985, on-the-spot-change (OTSC) 3343 was approved to move this requirement from section 8.12 to section 8.36. Section 8.36 is normally performed when the reactor coolant system is pressurized to at least 1000 pounds per square inch. At this pressure, reactor coolant temperature is significantly above 200 degrees F.

TS 4.1, Operational Safety Review, requires that equipment and sampling tests shall be conducted as specified in Table 4.1-2. Item 10 of Table 4.1-2 requires that accumulator boron concentration be sampled prior to heatup above 200 degrees F.

Contrary to the above, on June 22, 1985, the Unit 3 primary coolant system was heated above 200 degrees F without prior performance of the accumulator boron concentration analysis. The failure to meet the requirements of TS 4.1, Table 4.1-2, Item 10 is a violation against Unit 3 (250/85-24-03).

OTSC 3343 was written because a maintenance problem precluded filling and pressurizing the accumulators. TS 3.4.1.a specifies that the accumulator as well as other safety-related equipment are required to be operational prior to criticality except for low power physics testing. The personnel approving the OTSC did not realize that TS 4.1, Table 4.1-2, required accumulator sampling prior to exceeding 200 degrees F. Consequently, they did not realize that the OTSC contradicted the requirements of the TS and therefore represented a change to the intent of OP 0202.1. An OTSC written to change the intent of a procedure must be reviewed by the Plant Nuclear Safety Committee (PNSC) prior to approval by the Plant Manager. OTSC 3343 was not reviewed by the PNSC nor approved by the Plant Manager prior to issuance. This omission contributed to the violation of TS 4.1, Table 4.1-2, Item 10. An inspector followup item has been created to review the licensee's methods of making temporary changes to procedures to determine if a significant possibility exists that changes to the intent of a procedure could be made without the reviews and approvals required by TS 6.8.3, (IFI 250,251/85-24-05).

The failure of licensed personnel to be cognizant of the requirements of TS 4.1, Table 4.1-2, Item 10 is an additional example of Unresolved Item (UNR 250, 251/85-20-04).

b. During the performance of OP 0202.1, the inspectors noticed that the accumulator leak test was not begun at 1000 psi as is normally the case. The same maintenance problem prompting OTSC 3343 also precluded performing the leak test until the accumulator level could be raised to within the range of the level gages. The licensee did not make a procedure change in delaying this step because the accumulators are not required to be operable until the reactor is critical. Consequently, it was felt that the procedural step, 8.37, could be shifted to the end of OP 0202.1 and that the delay would not constitute a change to the procedure.

A review was made of the FSAR to determine the significance of accumulator check valve leak testing. Section 6.2.3, page 6.2-37, of the FSAR states that:

> "When the Reactor Coolant System is being pressurized during the normal heatup operation, the check valves are tested for leakage as soon as there is about 100 psi differential across the valve. This test confirms the seating of the disc and whether or not there has been an increase in the leakage since the last test. When the test is completed, the discharge line test valves are

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

opened and the Reactor Coolant System pressure increase is continued".

While the significance of the testing is not clearly defined, the mechanism of the testing is established. The licensee does not presently test the accumulator check valves in accordance with the description in section 6.2.3 of the FSAR. The significant differences between OP 4504.1, Accumulator Check Valves Backleakage - Periodic Test, and the FSAR description of the testing is:

(1) The check valve leakage is not tested as soon as there is about 100 psi differential across the valve. OP 4504.1 requires the reactor coolant system to be pressurized to at least 1000 psi. Since the accumulators are normally pressurized to 600 psi, the minimum differential during the test is 400 psi.

(2) The test is not conducted with the discharge test valves closed. OP 4504.1 requires these valves to be open prior to beginning the test.

(3) The reactor coolant system pressure increase is not halted during the test.

The determination of the adequacy of OP 4504.1 with respect to the FSAR description of section 6.2.3 is Inspector Followup Item (IFI 250, 251/85-24-07).

c. On June 24, 1985, during a tour of the control room, the inspector noticed that the source range high flux at shutdown annunciator was alarmed. The alarm was blocked for source range instrument N-31, which was indicating a count level in excess of the alarm setpoint. Source range instrument N-32 was not alarming. Apparently, the source range counts had increased during the recent heatup and the alarm setpoint for instrument N-31 had been reached. The alarm is normally set at a half decade above the average source neutron level. The annunciator alarm procedure did not address the actions to be taken upon receipt of the alarm for reasons other than an actual undesired power increase. OP 0205.1, Unit Shutdown - Full Load to Hot Shutdown Condition, addresses the initial setting of the alarm after power enters the source range. Subsequent resetting of the alarm, due to normal source range count changes occurring following borations, dilutions, temperature changes and decay, is not procedurally addressed. Consequently, when the high flux at shutdown alarm was received due to plant heatup, there was no guidance requiring the alarm to be readjusted to a level a half decade above the current source count level.

The purpose of the alarm is to alert the reactor operator to the unplanned increase in source counts. Additionally, the receipt of the alarm triggers the containment evacuation alarm to alert personnel working in the containment of the potential problem. On June 24, the Unit 3 containment evacuation alarm was out-of-service. The alarm is procedurally required to be operational during refueling and during containment entrances made when the reactor is at power. Since the reactor was in cold shutdown, the blocking of the high flux alarm and the degraded state of the containment evacuation alarm did not violate any procedure. However, the ability of the reactor operator to be forearned of a power increase and the ability of workers then inside the containment to be notified of the problem was diminished.

On June 28, 1985, following a Unit 3 reactor cooldown from hot shutdown, both source range nuclear instruments were found not to have their high flux at shutdown alarms set as a half decade above the average count level. Prior to the cooldown the alarms were set at 1000 counts per minute. Following the cooldown the decreased source count level required the alarm setpoints to be reduced to 380 counts per minute. Apparently, a lack of procedural guidance contributed to the decision to not reset the alarm.

The licensee, when informed of these discrepancies, took prompt action to reset the high flux alarm and to repair the containment evacuation alarm. Discussions with licensee supervisors confirmed that the intent is for these alarms to be properly set and fully operational.

For reasons of personnel safety, the licensee's need to supply additional guidance for the control of the high flux at shutdown alarm and the containment evacuation alarm will be carried as Inspector Followup Item (IFI 250, 251/85-24-08).

9. Engineered Safety Features Walkdown (71710)

The inspectors verified the operability of the Units 3 and 4 emergency diesel generator and emergency power systems by performing a complete walkdown of the accessible portion of the systems. The following specific items 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).

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

[illegible]

[illegible]

[illegible]

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d. that valves were in proper position, breaker alignment was correct, power was available and that valves were locked or lockwired as required;

e. local and remote position indication was compared and remote instrumentation was functional;

f. breakers and instrumentation cabinets were inspected to verify that they were free of damage and interference.

No violations or deviations were identified.

10. Plant Events (93702)

An independent review was conducted of the following events.

On June 17, 1985, on Unit 3 during performance of Off-Normal Operating Procedure (ONOP) 9608.1, 125 VDC Location of Grounds, the operator was temporarily opening and closing the breakers listed in an attempt to clear the ground. When breaker 9 was opened, a safety injection signal was generated for the B train. This started all B train safeguards equipment which was operable with the plant at cold shutdown.

On June 18, 1985, a bomb threat was received by the fossil unit operator. Security and the Nuclear Operations Department were immediately notified. Appropriate security measures were taken. A Security Alert was not declared.

On June 21, 1985, a subcritical reactor trip of Unit 4 occurred due to the loss of the 4C vital bus inverter. The loss de-energized one source range and one intermediate range nuclear instrument, NI-31 and NI-35, respectively, and each generated a reactor trip signal. The unit was cooling down to cold shutdown and continued the cooldown. The inverters are the subject of several evaluations and are being replaced.

On June 23, 1985, the fire team was dispatched when smoke was observed rising from the insulation on the 3B boric acid pump suction piping. An actual fire was not observed. Recirculation of boric acid storage tanks A and C was initiated, and repair of the heat tracing circuits was accomplished. The circuits, 8A and 8B, affect the suction lines of 3A, 3B, 4A and 4B boric acid transfer pumps. Unit 3 was in hot shutdown and Unit 4 was at 26 percent power and holding due to both a chemistry hold and the boric acid heat tracing problem. The Technical Specifications were complied with.

No violations or deviations were identified in this section.

11. Independent Inspection

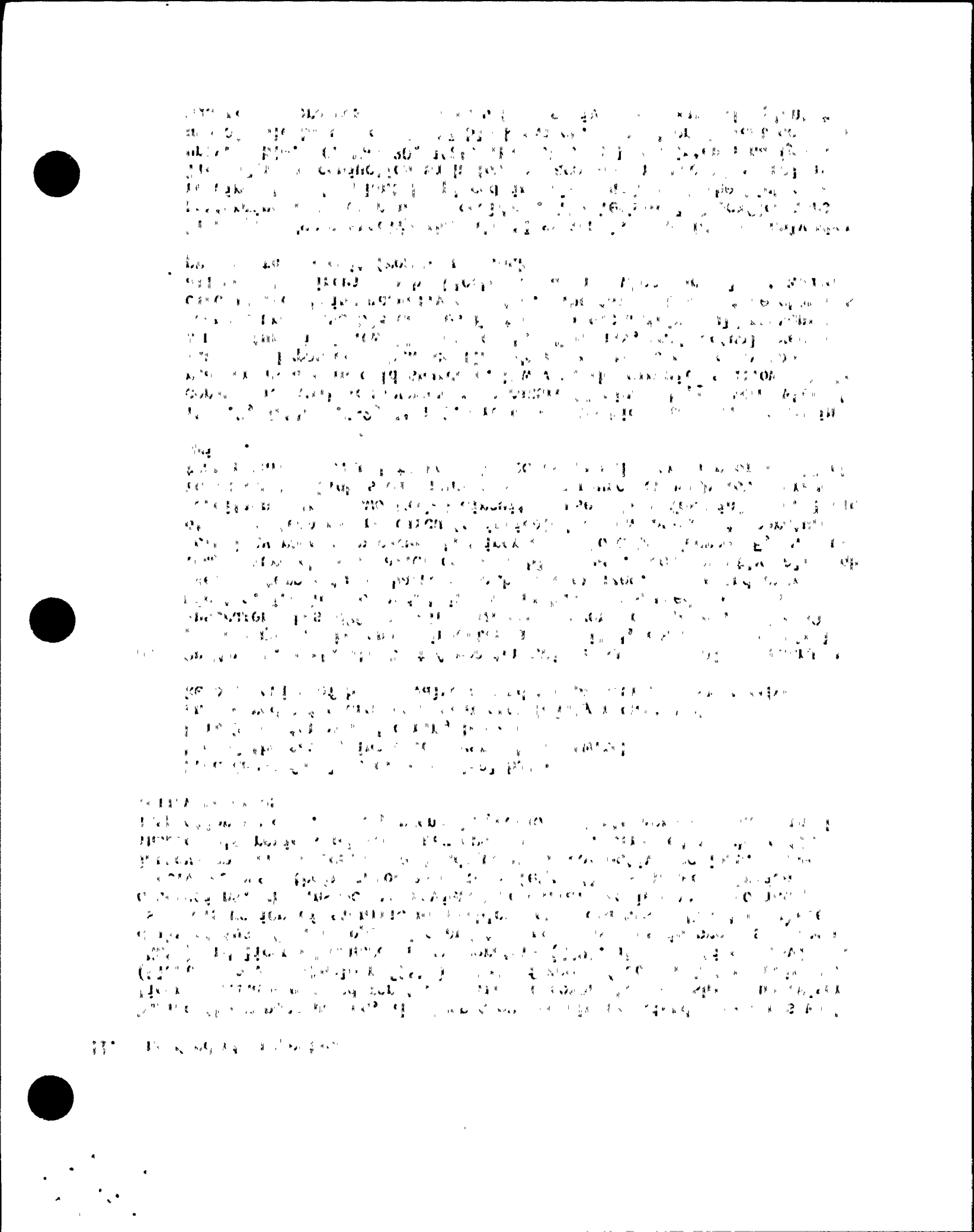
During the report period, the inspectors routinely attended meetings with licensee management and monitored shift turnovers between shift supervisors (Plant Supervisor-Nuclear [PSN]), shift foremen (Nuclear Watch Engineers [NWE]) and licensed control room operators (CRO). These meetings provided a daily status of plant operating and testing activities in progress as well as a discussion of significant problems or incidents. Based on these discussions, the inspectors reviewed potential problem areas to independently assess: their importance to safety, the proposed solutions, improvement and progress, and adequacy of corrective actions. The inspector's reviews of these matters were not restricted to the defined inspection program. Independent inspection efforts were conducted in the following areas:

Procedures for loss of electrical busses
Use of the safety injection system block switch
Unit 3 reactor vessel o-ring leakage
Engineered safeguards equipment operability requirements
Repositioning of bypass valve around the pressurizer spray valve

a. On May 30, 1985, the Unit 4 reactor tripped due to a failed instrument power supply. The spare inverter also failed, consequently, vital instrument bus 4P07 remained without power for approximately 40 minutes. The loss of vital instrument bus 4P07 caused one of the three average temperature channels to be deenergized. A second average temperature channel failed due to a blown fuse. Consequently, although actual average temperature had increased above 543 degrees F, two out of three temperature circuits indicated a low average temperature condition. These two failed circuits caused the safety injection logic to allow the high steam line flow in conjunction with low average temperature SI signal to be defeated by manual operation of the block switch.

TS 3.5, Table 3.5-2, Item 1.5 requires the high steam line flow in conjunction with low average temperature SI signal be operable when the reactor is not in cold shutdown. However, the circuit is allowed to be manually bypassed, when cooling down the reactor and average temperature is below 543 degrees F. Normally, with actual average temperature above 543 degrees F, the SI logic matrix would prevent the circuit from being manually defeated. The failed temperature channels allowed the circuit to be blocked at a time when normally it would prevent the circuit from being blocked.

Plant procedures specify that the SI system is to be blocked only when performing a reactor plant cooldown. The Technical Specifications require that the plant be placed in cold shutdown if the high steam line flow in conjuction with low average temperature SI signal is unavailable. On May 30, 1985, this SI signal was intentionally made unavailable by use of the SI block switch. A preplanned plant cooldown was not in progress and no thought was given to taking the plant to



cold shutdown. All other SI logic circuits were properly functioning and were available for automatic initiation. Manual initiation was available at all times.

The signal was blocked for approximately one hour at a time when the PSN felt he might receive a high steam line flow signal due to use of the atmospheric steam valves to dissipate decay heat. The high steam line flow signal, if received, in conjunction with the erroneous low temperature signals would have resulted in engineered safeguards actuation. The receipt of an actual high steamline flow signal due to the use of the atmospheric steam valves is not uncommon. However, the PSN's actions removed a protective feature at a time when that protective feature should have been present. Additionally, the receipt of an engineered safeguards actuation while the unit was recovering from the reactor trip would not have had significant adverse effects on the operation of the plant.

The use of the SI block switch to prevent the automatic initiation of SI while average temperature was above 543 degrees F is a violation against Unit 4 (251/85-24-01).

b. Between June 23 and June 26, 1985, Unit 3 was maintained at hot shutdown with all three 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. Additionally, TS 3.4.1.a requires the refueling water storage tank to contain at least 320,000 gallons of borated water; four safety injection pumps to be operable; two residual heat removal pumps to be operable; and two residual heat removal heat exchangers to be operable prior to criticality, except for low power physics tests. Since Unit 3 was not critical and was preparing for low power physics tests, the licensee was in compliance with TS 3.4.1.a.

While TS 3.4.1.a clearly prevents a reactor from being made critical, except for physics tests, without the designated equipment, it does not specifically address the permisibility of taking a plant from cold shutdown to hot shutdown. Consequently, it is not clear whether a unit with a power history can be heated from cold to hot shutdown and, subsequently, remain in hot shutdown without the equipment mentioned in TS 3.4.1.a.

TS 3.4.1.b addresses LCO for the equipment of TS 3.4.1.a and allows power operation to continue for short periods of time following the loss of certain equipment. After the action time limits are exceeded, the reactor must be shutdown. Additional time is then available to repair the equipment but if that time is exceeded the reactor must be placed in cold shutdown. If more equipment is inoperable than is addressed by the LCO the reactor must be shutdown within seven hours and cooled to cold shutdown within the following 30 hours.

TS 3.4.1.b applies only to reactors operating at power. However, it implies that remaining in hot shutdown for extended periods of time without the equipment of TS 3.4.1.a is undesirable. Whether a reactor with a power history can be heated from cold to hot shutdown with any of the equipment of TS 3.4.1.a inoperable is an unresolved item pending NRC evaluation of the TS (UNR 250, 251/85-24-04).

c. The heating of Unit 3 from cold to hot shutdown and then maintaining hot shutdown conditions for over 48 hours does not fall into the catagory of UNR 250, 251/85-24-04 because the reactor had no power history and it was being prepared for low power physics testing. Consequently, in addition to being heated to hot shutdown, it could have been taken critical without the three accumulators in service. On June 26, 1985, Unit 3 was returned to cold shutdown due to an unisolable leak of approximately two gpm through the reactor vessel o-rings. The accumulators were still out of service.

The bypass valve around the pressurizer spray valve was the subject of a licensee evaluation to determine the proper position to allow one gpm flow. The evaluation revealed that the initially determined position of one half turn open was not correct and that the valve should be repositioned to one eighth turn open. The two valves per unit were repositioned. The pressurizer spray and heater evaluation will continue to followed.