**ENCLOSURE 2**

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-382/95-22

License: NPF-38

Licensee: Entergy Operations, Incorporated
P.O. Box B
Killona, Louisiana 70066

Facility Name: Waterford Steam Electric Station, Unit 3

Inspection At: Waterford 3

Inspection Conducted: December 31, 1995, through February 3, 1996

Inspectors: T. W. Pruett, Resident Inspector
W. F. Smith, Senior Resident Inspector, River Bend Station
J. E. Tedrow, Senior Resident Inspector, Grand Gulf

Approved: P. H. Harrell, Acting Chief, Project Branch D — 3-25-96 Date

Inspection Summary

Areas Inspected: Routine, announced inspection of plant operations, maintenance and surveillance observations, plant support activities, and onsite engineering and review of a licensee event report (LER).

Results:

Plant Operations

- Entries into the station log were complete and thorough. Annunciator response, access to the control room, and communications were inconsistent between the operating shifts. Communications between control room operators and operators in the plant using the telephone were informal. Based on the inspectors' observations, control room formality improved (Section 2).

- The inspectors considered the licensee's processes for control room deficiencies and inoperable annunciators to be good in that the licensee: (1) reinstated the practice of using deficiency stickers to identify inaccurate control room indications, (2) the oldest disabled annunciator was 3 months, (3) there was adequate redundancy for accident assessment, and (4) operators were familiar with the reasons for instrument inaccuracies (Section 2).

Maintenance

- The wet cooling tower crossconnect valves (ACC-138A and -1138B) were degraded to the point that position indication in the control room was unreliable and operation of the valves, using the local operator, could not be performed. The failure to identify and perform corrective maintenance for these valves was considered a poor maintenance work practice (Section 3.1).

- The total corrective maintenance backlog, including minor maintenance and outage items, was approximately 2,300 open items. Even though the licensee did not trend the amount of open safety-related maintenance items, the inspectors determined that approximately 40 percent (about 920) of the open corrective maintenance items were safety-related. The licensee maintained that the maintenance backlog was acceptable based on component reliability and availability factors (Section 3.2).

- An evaluation to determine the methodology for assigning priorities to maintenance items had not been completed even though the review had been initiated over 2 years ago (Section 3.2).

- The licensee failed to implement a program to ensure mechanical retests were identified, scheduled, and completed and is a violation of Technical Specification (TS) 6.8.1.a (Section 3.3).

- Operations reperformed the integrated leakage test for systems containing primary coolant outside of containment due to the inspectors' concerns regarding the adequacy of the December 1995 test results. As a result of the performance of the second integrated systems leakage test, operations initiated 30 condition identification deficiencies for 9 actual and 28 potential leakage sources. In addition, the integrated leakage test surveillance was performed 21 months after the previous completion date instead of every refueling cycle interval or less (18 months), as required by TS 6.8.4.a. This is a violation (Section 4).

- The licensee assumed operability of safety-related systems with outstanding mechanical retests based on the performance of a surveillance test that had not been completed. The licensee's initial response to mechanical retest concerns was consistent with recent examples where the licensee assumed functionality of systems and components without verification of the assumptions (Section 4).

Engineering

- The licensee failed to verify the adequacy of the corrective actions specified on Condition Report (CR) 95-1242, in that: (1) the reliability of the wet cooling tower crossconnect valves (ACC-138A and -138B) were not verified prior to changing the safety function of the

valves from passive-closed to both passive-closed and active-open, and (2) the ability to transfer water through the nonsafety-related wet cooling tower crossconnect line was not verified. The failure to verify the effectiveness of corrective actions to ensure reliability of the ultimate heat sink is a violation of TS 6.8.1.a (Section 3.1).

- The failure to identify and perform corrective maintenance on Valves ACC-138A and -138B was an indication that system engineering did not maintain adequate oversight of the functioning of their assigned systems (Section 3.1).

- Engineering's use of unreviewed Evaluation W3C1-94-0029 to determine the acceptability of leakage from systems containing primary coolant outside of containment was inappropriate because the evaluation was less conservative than the leakage specifications described in the Final Safety Analysis Report (FSAR) and the Safety Evaluation Report (SER) (Section 4).

- Engineering's failure to initiate a CR to document the abnormally low flow in Cold Injection Leg 1A, following the October 1995 surveillance test, is an example of personnel not questioning what adverse conditions may be present that could affect system operation and is a violation of TS 6.8.1.a (Section 5.2).

Plant Support

- Security's failure to ensure a temporary enclosure for the vacuum degasifier pumps and the trench between the ionics trailers and the polisher building were adequately illuminated is a violation of the Security Plan (Section 6.1).

- The total square footage of contaminated areas for the 3 months prior to the forced outage was between 1,619-1,877 square feet. On January 26, 1996, the total contaminated area was 3,048 square feet. The increase in contaminated square footage was attributed to slow restoration of plant spaces following the refueling outage due to the holiday season, efforts to improve plant housekeeping, and providing personnel resources for the River Bend Station refueling outage (Section 6.2).

Summary of Inspection Findings:

New Items

Violation 382/9522-01 - Example 1: Failure to verify the adequacy of corrective actions provided on a CR (Section 3.1).

Violation 382/9522-01 - Example 2: Failure to initiate a CR after identification of an adverse condition involving reduced flow through Cold Leg Injection Loop 1A (Section 5.2).

Unresolved Item 382/9522-02: Review of the licensee's operability evaluation and corrective actions for the ultimate heat sink (Section 3.1).

Violation 382/9522-03: Failure to identify, schedule, and complete mechanical retests (Section 3.3).

Violation 382/9522-04: Failure to perform the integrated leak test for systems outside of containment every refueling cycle interval or less (Section 4).

Violation 382/9522-05: Failure to provide adequate illumination of areas within the protected area (Section 6.1).

Closed Item

LER 382/95-001: Moderator Temperature Coefficient Testing (Section 7).

Attachments:

- Persons Contacted and Exit Meeting

## DETAILS

### 1 PLANT STATUS

The plant operated at essentially 100 percent power during this inspection period.

### 2 PLANT OPERATIONS (71707)

During the past 6 months, the licensee initiated corrective actions to improve control room formality. To assess the effectiveness of the improvements, the inspectors performed several observations of control room activities during this inspection period. Entries into the station log were complete and thorough. However, annunciator response, access to the control room, and communications were inconsistent between the operating shifts. Communications between control room operators and operators in the plant using the telephone were informal. Based on the inspectors' experience and observations, the licensee's control room formality had improved.

On January 17, 1996, the inspectors reviewed the number of control room deficiencies and inoperable main control room annunciators. Seven annunciators were disabled by pulled cards and 33 deficiencies were listed in the control room logbook.

The oldest disabled annunciator was approximately 3 months, which was an indication that apropriate attention was being directed to correct these problems. The inspectors discussed the inoperable annunciators with licensee personnel, as to their function and inputs, and did not identify any concerns with the licensee's action to temporarily disable the annunciators.

The inspectors utilized the licensee's computerized deficiency tracking system to review the control room deficiencies and discussed the individual deficiencies with licensee personnel. The licensee's philosophy was to place deficiency tags on those control room indicators that did not provide accurate indication of actual system parameters. The practice of placing deficiency tags on main control board instrumentation was discontinued in the past, but was reinstated on January 16. Due to the addition of deficiency tags on the main control board, the inspectors found that control room personnel were aware of the status of control room instrumentation. The inspectors reviewed each of the 33 instrument deficiencies for impact on the operators' ability to assess or respond to accident conditions. Of the 19 nonsecondary deficiencies, the inspectors found that sufficient redundancy had been provided for those indications to support assessment of an accident.

The inspectors reviewed Procedure OI-002-000, "Annunciator, Alarm, and Control Room Instrumentation Status Control," which provided direction for operators to perform weekly and quarterly audits of the annunciators and inoperable instrumentation to identify the status of corrective actions to correct the deficiencies. The inspectors reviewed the latest audits, which were contained

in the log book. These audits were transmitted to management so that appropriate priorities could be established for correcting the deficiencies. The inspectors considered the licensee's processes for control room deficiencies and inoperable annunciators to be good.

## 3 MAINTENANCE OBSERVATIONS (62703, 37551)

### 3.1 Wet Cooling Tower Crossconnect Valves ACC-138A and -138B

Valves ACC-138A and -138B are fail-closed, air-to-open, butterfly valves. The solenoids that control air pressure to the valves are powered from a safety-related uninterruptible power supply, but the only air source for the valve actuator is supplied from the nonsafety-related instrument air system. The piping between the valves, which connects the wet cooling tower basins, is classed as nonsafety-related piping.

Until December 2, 1995, Valves ACC-138A and -138B had a passive-closed safety function to ensure separation of the ultimate heat sink water basins. CR 95-1242 was initiated to identify that adverse conditions could affect operability of the ultimate heat sink, in that one train of the ultimate heat sink would be depleted within 5.5 days following a loss-of-coolant accident, instead of the design value of 7 days. As part of the corrective actions, the licensee took credit for redundant safety-related, seismically-qualified Valves ACC-138A and -138B, which could be opened to provide makeup water from one wet cooling tower basin to the other, thereby ensuring that an adequate supply of water was available. See NRC Inspection Report 50-382/95-10 for additional details. Based on the belief that the valves could be used, the CR was closed without additional actions being taken.

During plant tours of the dry cooling tower and wet cooling tower areas on January 22, the inspectors noted that the material condition of Valves ACC-138A and -138B was severely degraded. The actuator, limit switches, handwheel, and stem on Valve ACC-138A were rusted sufficiently to seriously question valve operability. The licensee identified the degraded condition of Valve ACC-138A on May 20, 1995, but had not taken any actions to restore the material condition of the valve.

The actuator, limit switches, handwheel, and stem on Valve ACC-138B were sufficiently painted over to question valve operability. The licensee had not identified the degraded material condition of Valve ACC-138B. The inspectors reviewed the maintenance history for Valves ACC-138A and -138B and determined that, according to the available records, no maintenance or testing had ever been performed on the valves. The material condition of the valves concerned the inspectors since the licensee had recently taken credit, in response to CR 95-1242, for the valves as a source of makeup water following a loss-of-coolant accident.

Because of the inspectors' concerns, the licensee performed a stroke test of Valves ACC-138A and -138B from the control room on January 22. Valve ACC-138A stroked open but, due to excessive corrosion, the limit switches did not

provide an indication in the control room that the valve had changed positions. The licensee was unable to restore position indication for Valve ACC-138A in the control room. Valve ACC-138B stroked open but, due to excessive painting, the limit switches did not initially provide an open indication in the control room. After several cycles of the valve and removal of paint from the limit switches, the position indication for Valve ACC-138B was restored in the control room.

The licensee attempted to manually open the valves using the local operator but, due to the degradation, Valves ACC-138A and -138B did not open. The inability to open the valves manually concerned the inspectors because the air supply to the actuators was from nonsafety-related instrument air, which would not be available following a loss-of-coolant accident with a loss of offsite power. The loss of air to the actuators, combined with the inability to locally open the valves using the manual actuator, could have prevented the licensee from utilizing the additional volume of water from one basin to augment the supply of water to the operational train of ultimate heat sink. The licensee stated that additional makeup water supplies to the basin were available if Valves ACC-138A and -138B failed to open and revisions to procedures were being made to specify other potential makeup sources to the wet cooling tower basins. Nevertheless, the inspectors determined that the failure to identify and perform corrective maintenance on Valves ACC-138A and -138B was an indication that system engineering did not maintain adequate oversight of the functioning of their assigned systems.

Procedure UNT-006-011, "Condition Reports," Section 5.6.3, states, in part, that quality assurance corrective action personnel will review the effectiveness of corrective actions and associated documentation and that the verification should be commensurate with the safety significance of the condition. The inspectors concluded that the licensee did not adequately verify the effectiveness of the corrective actions for CR 95-1242, in that: (1) the operability and reliability of Valves ACC-138A and -138B were not verified prior to changing the safety function of the valve from passive closed to both passive closed and active open, and (2) the ability to transfer water through the nonsafety-related wet cooling tower crossconnect line was not validated. The failure to verify the effectiveness of corrective actions specified on CR 95-1242 is the first example of a failure to follow a procedure and is a violation of TS 6.8.1.a (382/9522-01).

The licensee entered Site Directive W4.101, "Operability/Qualification Confirmation Process," on January 23, to evaluate the operability of the ultimate heat sink if one train was considered inoperable. The licensee initiated the evaluation as a result of the inspectors identifying that water could not be transferred from one cooling tower to the other. The evaluation concluded that wet cooling tower makeup sources would not be required, following a loss-of-coolant accident, provided the 4-day average temperature was less than 84°F. Additionally, the licensee concluded that the ultimate heat sink would be operable during the design basis tornado event since additional methods of providing water to the wet cooling tower basin, other

than the wet cooling tower crossconnect line, were available. A review of the licensee's evaluation of the operability of the ultimate heat sink will be performed by the NRC and will be tracked as an unresolved item (382/9522-02).

3.2 Maintenance Backlog

The inspectors performed a review of the maintenance backlog and noted that the licensee's average daily total corrective maintenance backlog, including minor maintenance and outage items, was steady at approximately 2,300 open items. This total included approximately 290 minor maintenance items and 460 outage items.

The inspectors questioned the licensee to determine the amount of safety-related versus nonsafety-related maintenance items. The licensee informed the inspectors that the number of open safety-related maintenance items was not trended. The inspectors obtained a copy of the licensee's weekly corrective maintenance report and determined that approximately 40 percent (about 920) of the open corrective maintenance items were safety-related, of which approximately 65 percent (about 600) appeared to be past due. The inspectors based the past due observations on open items that were classified as a Priority 3 (work completion within 72 hours), Priority 4 (work completion within 7 days), Priority 5 (work completion within 30 days), or Priority 6 and 7 items (work by specified date or no completion time required), with work packages that had been authorized to be performed for more than 1 month.

The maintenance scheduling superintendent stated that Procedure PLG-009-007, "Routine Scheduling of Station Activities," Attachment 6.1, "Priority Codes," Note 3, indicated that the priority of the items was based on relative importance and not necessarily an estimate of the expected work completion date. For example, a Priority 3 item would not necessarily be performed within 72 hours, but should be completed before a Priority 4 item.

The inspectors discussed the corrective maintenance backlog with the maintenance superintendent. The maintenance superintendent stated that he was aware of the safety-related maintenance backlog and that the backlog of safety-related items was acceptable based on a high component availability and reliability. The maintenance supervisor also stated that the priority codes assigned to maintenance items could be improved, the reliability of system components was good, and a review of scheduling practices had been initiated by the scheduling department, which would change the methodology in assigning priority codes to ensure reliability of the component was a factor.

The inspectors questioned the maintenance scheduling superintendent and determined that the review of scheduling practices had been initiated approximately 2 years ago and had not been completed. The superintendent stated that the review had been reassigned to another supervisor and that the changes should be implemented within the next 6 months. The inspectors considered the timeliness of the licensee's actions for reviewing scheduling practices to be marginally adequate.

3.3 Mechanical Retests

On December 4, 1995, the inspectors questioned the licensee to determine which mechanical retests were outstanding on safety-related systems following Refueling Outage (RFO) 7. On December 12, the inspectors were provided 11 safety-related work authorizations (WA) with outstanding mechanical retests. On January 8, the inspectors toured plant spaces and noted two mechanical retest tags installed on valves that were not included on the list of 11 WAs provided by the licensee on December 12. Following additional questioning, the inspectors were provided with another list, on December 4, with 20 outstanding mechanical retests. The list did not include 5 of the 11 WAs provided on December 12 and 1 of the 2 tags identified by the inspectors on January 8.

On January 12, the inspectors were provided with another list of incomplete mechanical retests. The licensee stated that the list was representative of all remaining mechanical retests. The inspectors reviewed the list and the licensee's methodology for developing the list and concluded that the licensee had identified the WAs with mechanical retests that had not been completed. As of January 12, at least nine retests had not been performed.

The inspectors noted that the affected components had been removed from the operations department equipment out-of-service log without all of the mechanical retests being signed in the WA as having been completed. Additionally, the licensee did not have programs or procedures to ensure that mechanical retests were scheduled for completion after the system was returned to service. The licensee stated that operability of a component was determined based on the operations department test and not on the mechanical retests. The maintenance supervisor stated that there was some confusion between operations and maintenance concerning who was responsible for ensuring the mechanical retests specified in the WA were completed. The licensee initiated a CR to evaluate methods for ensuring mechanical retests were completed.

The inspectors noted that operations verification of component operability may not be totally adequate in all cases to ensure system operability. Specifically, the failure to perform mechanical retests that require inspections at normal operating pressure for leakage could result in unidentified leak paths that could potentially affect system operability or offsite dose releases. The licensee informed the inspectors that no operability concerns existed with the incompletion of the mechanical retests because a surveillance test was performed at the end of the refueling outage and would identify any excessive leakage. Based on further reviews performed by the inspector, it was determined that the test was not being appropriately performed. See Section 4 for a discussion of this test.

The inspectors concluded that the licensee's failure to provide procedural guidance to ensure mechanical retests were identified, scheduled, and completed is a violation of TS 6.8.1.a (382/9522-03).

## 4 SURVEILLANCE OBSERVATION (61726, 37551)

The inspectors performed a review of the licensee's implementation of TS 6.8.4.a, which requires the performance of an integrated leak test for systems containing primary coolant outside of containment at refueling cycle intervals or less. The licensee implemented the integrated leak test by issuance of Procedure OP-903-110, "RAB (Reactor Auxiliary Building) Fluid Systems Leak Test."

A review was performed of this test, in response to the statement made by licensee personnel that there were no operability concerns for mechanical retests that had not been performed following the refueling outage because excessive leakage from safety-related systems would have been detected during the performance of system leakage tests. See Section 3.2 for a discussion of the review of the mechanical retest program.

On January 17, the inspectors requested a copy of the integrated system leak test results and was informed that the surveillance test had not been completed. The inspectors reviewed the incomplete surveillance test and noted that only two systems had been completed prior to December 4. The safety injection sump system was performed on October 26 and the hydrogen analyzer system was completed on October 11, as part of the licensee's local leak rate testing program. The safety injection and containment spray systems, which were the inspectors' focus of mechanical retest concerns, had not been performed at the time of the licensee's statement of no operability concerns on December 4. The inspectors noted that the licensee's statement regarding the need not to perform mechanical retests, because the surveillance test was performed, was consistent with other recent examples in which some licensee personnel had assumed reliability of systems and components without verification of the basis for the assumptions made by engineering personnel. In this case, the licensee assumed safety-related systems were operable with outstanding mechanical retests, based on the performance of a surveillance test that had not been completed.

The inspectors noted that only two leaks on High Pressure Safety Injection (HPSI) System Train A (pump seal leakage and pump suction vent valve) and one leak on Containment Spray System Train A (header drain valve) were identified during the initial performance of the integrated systems leakage test. The inspectors determined that the licensee's identification of three leaks was inconsistent with the 25 radiological leakage containment devices installed on plant systems to collect system leakage. Because of the inspectors' concern that the integrated systems leakage test may not have been adequately completed, the licensee reperformed Procedure OP-903-110.

On January 24, the inspectors compared the first performance of the leakage test with the second integrated systems leakage test and noted that the licensee initiated approximately 30 condition identification tags for leakage or the presence of dry boric acid on system components and identified an additional 8 leakage sources and 36 potential leakage sources. One small active leakage source was noted by the inspectors on Valve SI-225B; however,

the licensee identified it as an indication of dry boric acid. Even though the number of leak sources increased from 3 to 12, the total integrated leakage was essentially the same (less than 7 ml/min).

The inspectors reviewed the RFO 6 integrated leakage test results and determined that the licensee had not performed the surveillance test required by TS 6.8.4.a at each refueling cycle interval or less (i.e., less than 18 months). The leakage test for RFO 6 was completed on April 23, 1994. The leakage test for RFO 7 was completed on January 23, 1996, an interval of 21 months. The licensee stated that the surveillance interval had not been exceeded since they were within the TS 4.0.2 maximum allowable extension of 25 percent of the normal surveillance interval or 22.5 months.

The inspectors reviewed the application of the TS 4.0.2 surveillance interval with the NRC's Office of Nuclear Reactor Regulation and determined that the 25 percent extension did not apply to the administrative section of the TS. Therefore, the licensee could not exceed 18 months since TS 6.8.4.a specified that the integrated leakage test would be performed at refueling cycle intervals or less. This determination was consistent with Section 1.9.37 of the FSAR and NUREG-0737, "Clarification of TMI Action Plan Requirements," which indicated that the integrated leakage test for systems outside of containment, which are likely to carry radioactive materials, will be performed at intervals not to exceed each refueling cycle. The failure to perform the integrated leakage test surveillance within 18 months is a violation of TS 6.8.4.a (382/9522-04).

The licensee stated that the failure to perform the surveillance required by TS 6.8.4.a was an administrative issue and not a safety significant issue. The inspectors noted that a 3 month delay in performing the leak test was of minimal safety significance, but the misinterpretation of the TS frequency was of concern.

The inspectors reviewed Procedure OP-903-110 and determined that the acceptance criteria did not provide a limit for total system leakage nor did it require that the licensee evaluate system leakage on a continuing basis. Procedure OP-903-110 did state that there was not a quantitative acceptance criteria, but that the control room supervisor/shift supervisor was required to qualitatively assess the results of the test. The inspectors reviewed Section 15.6.3.3.5.1.2, "Leakage From Engineered Safety Features Components Outside Containment," of the FSAR; NUREG-0787, "Safety Evaluation Report Related to the Operation of Waterford Steam Electric Station, Unit Number 3;" and licensee Interoffice Correspondence W3C1-94-0029, "Impact of the SI-214 Valve Leakage on Offsite Dose," dated September 9, 1994, and identified several inconsistencies related to the identification of an acceptable leakage limit from safety-related systems.

| Source Document | Leakage Specification |
|---|---|
| FSAR Table 15.6-9 | HPSI Pump Seals - 200 cc/hr<br>Containment Spray Pump Seals - Not Specified<br>Low Pressure Safety Injection Pump Seals - 100 cc/hr |
| SER Section 15.4.7 | Licensee Estimate - 500 cc/min (30,000 cc/hr)<br>NRC Evaluated Leakage - 1,000 cc/min (60,000 cc/hr) |
| Evaluation W3C1-94-0029 | 0.5 gpm (113,550 cc/hr) |

Each of the above leakage specifications indicated that the amount of iodine released, as a result of the leakage, would be processed by the charcoal absorbers in the controlled ventilation area system and would not exceed the limits specified in 10 CFR Part 100.

Evaluation W3C1-94-0029 was initiated to determine the offsite dose consequences from a 0.5 gpm leak from Valve SI-214. The licensee determined that the offsite doses from a 0.5 gpm leak were well within the 10 CFR Part 100 acceptance criteria. The licensee stated that the evaluation was not intended to be used to update the FSAR; therefore, only a peer review of the evaluation was performed instead of an independent supervisory review.

Engineering used unreviewed Evaluation W3C1-94-0029 to disposition a deficiency identified on a CR, which involved a 125 cc/min (7500 cc/hr) leak on HPSI Pump A on August 25, 1995, as acceptable since the leak rate was less than the previously analyzed 0.5 gpm. Consequently, repairs to the HPSI Pump A seal were delayed on two occasions with final repairs to HPSI Pump A completed on January 24, 1996, after concerns were raised by the inspectors regarding acceptable leakage rates.

The inspectors concluded that the use of unreviewed Evaluation W3C1-94-0029 was inconsistent with the highest evaluated leakage in licensing basis documents. Additionally, the use of unreviewed Evaluation W3C1-94-0029 to defer maintenance was not appropriate because the evaluation was less conservative than the leakage specifications described in the FSAR and the SER, and actions were not taken to address the different values provided in these documents.

## 5 ONSITE ENGINEERING (37551)

### 5.1 Special Report on Emergency Diesel Generator (EDG) Trip

The inspectors reviewed Special Report SR-95-004-00, dated November 27, 1995, which described a trip of EDG B on turbocharger low lube oil pressure during surveillance testing. The inspectors discussed this event with the system engineer and reviewed the schematic of the pneumatic control system and the vendor technical manual section on the lubricating oil system.

The lubricating oil system supplies variable oil pressure to the diesel turbocharger, which increases with engine load and turbocharger discharge pressure. The variable oil pressure is controlled by the control air system, which positions an air-operated throttle valve, thereby increasing/decreasing the oil supply to the turbocharger bearings. Upon a loss of control air, a shuttle valve repositions and directs lower pressure control air to the throttle valve, thereby lowering lube oil pressure to the turbocharger bearings. According to the vendor manual, this lower pressure oil supply is sufficient for continued engine operation. The low lube oil pressure trip setpoint is also variable, based on engine load.

The licensee's investigation concluded that a failed diaphragm on a combustion air inlet temperature control valve caused a reduction in control air system pressure, which was sufficient to allow the shuttle valve to reposition. This event happened at a load of approximately 3.5-4.0 MW. The licensee believed that the decrease in lube oil pressure following the shuttle valve repositioning was sufficient to activate the low pressure trip.

The vendor informed the licensee that the temperature control valve was not needed in the system and that sufficient jacket water cooling would be available to cool other engine components with the temperature control valve full open. The licensee's immediate corrective action included removing the control air from the temperature control valve to allow the valve to remain in the fully open position. The licensee was considering deleting these valves from the system.

Since this trip is bypassed during an emergency diesel start and the turbocharger receives adequate lube oil on a loss of control air, the inspectors concluded that this issue had a small impact on the ability of the EDGs to perform their intended safety functions.

5.2 Safety Injection Flow Balance Test

The inspectors performed a review of Procedure OP-903-108, "Safety Injection Flow Balance Test," in response to CR 96-0011, dated January 4, 1996, which involved the improper installation of the flow orifice plate for Cold Leg 1A Injection Flow Instrument SI-IFE-0311. The discrepancy was identified as a result of a task force review of instrument calibrations initiated in response to discrepancies with the accuracy of licensee calculations for instrument setpoints. See NRC Inspection Report 50-382/95-10 for additional details. CR 96-0011 documented that the flow balance data obtained on October 17, 1995, indicated that the Loop 1A flow was 10-20 percent lower than historical data and the flow indicated in the other three cold leg injection loops.

The inspectors reviewed the data from flow tests performed since April 1991 and determined that the October 1995 flow data for Loop 1A (202 gpm) was approximately 40 gpm lower than historical data (235-242 gpm). Additionally, the sum of the cold leg injection line flow rates, excluding the highest flow rate, was 679 gpm, which was 28-41 gpm below historical data. TS 4.5.2.h requires the licensee to verify that the sum of the cold leg injection line

flow rates, excluding the highest flow rate, is greater than or equal to 675 gpm. Because the flow rate exceeded the minimum criteria specified in the TS, engineering personnel did not question the reduction in Loop 1A flow or the reduction in the sum of the cold leg injection loop flows.

The inspectors noted that engineering personnel did not initiate a CR to identify that the Loop 1A flow was abnormally low following the October 1995 surveillance test. This is an example of personnel not questioning what adverse conditions may exist that could affect system operation and not generating a CR. This is the second example of the failure to follow a procedure and is a violation of TS 6.8.1.a (382/9522-01).

## 6 PLANT SUPPORT ACTIVITIES (71750)

### 6.1 Illumination of Protected Area

Between 7 and 8:30 p.m. on January 24, 1996, the inspectors performed a tour of the protected area to determine if all areas were adequately illuminated. The tour was initiated approximately 1.5 hours after sunset. During the tour, the inspectors observed that the temporary enclosure for the vacuum degasifier pumps and a trench between the ionics trailers and the polisher building were not illuminated.

The temporary enclosure for the vacuum degasifier pumps was installed for cold weather protection purposes. The enclosure consisted of plastic sheets draped over structural supports with slits in the material for personnel access. The inspectors were unable to view objects within the enclosure at a distance of 2-3 feet. The inspectors also noted that temporary lighting had been installed in the enclosure but that the lights were not energized. The inspectors notified security upon discovery of the discrepancy and performed an additional tour approximately 1 hour later. During the second tour, the inspectors verified that the enclosure was adequately illuminated. The inspectors were informed that the electric cord for the lights had been removed from the receptacle, the security lieutenant restored the lighting, and illumination in the area without the temporary lighting was greater than 0.2 footcandles. The inspectors were unable to determine when the cord was removed from the receptacle.

The inspectors also observed that a 40-foot trench between the ionics trailers and the polisher building had the metal covers removed at each end and that lighting was not provided inside the trench. The inspectors were unable to see objects at one end of the trench while viewing from the opposite end. The inspectors notified security upon discovery of the discrepancy and performed an additional tour approximately 1 hour later. During the second tour, the inspectors observed that the licensee had posted a security officer at the openings of the trench. The inspectors were informed by the licensee that the illumination in the trench was less than 0.2 footcandles.

The inspectors concluded that the failure to ensure adequate illumination existed in the temporary enclosure and in the trench is a violation of

Section 6.3 of the Security Plan, which states that illumination in most open parts of the protected area be at least 0.2 footcandles (382/9522-05).

Security management stated that the inspectors performed their tour of the temporary enclosure and the trench area prior to the security officer's patrol and that the discrepancy would probably have been identified by the security officer. The inspectors reviewed the patrol log and determined that the protected area patrol was performed between 6:42 and 7:35 p.m. and the inspectors may have toured the area prior to the security officer.

In response to security management's observations regarding the timing of the tour of the trench, the inspectors questioned the construction department to determine when the metal covers on the trench had been removed. Construction stated that the covers were removed on January 23, the day prior to the inspector's observations. The inspectors concluded that the licensee had several opportunities to identify that the trench required temporary lighting before identification of the problem by the inspectors.

6.2 Square Footage of Contaminated Space

During tours of plant spaces on December 27-28, 1995, the inspectors observed that the total square footage of contaminated area appeared greater than the amount of contaminated square footage prior to the June 1995 forced outage. The inspectors reviewed a summary of contaminated areas and determined that the total square footage of contaminated area for 3 months prior to the forced outage was between 1619 and 1877 square feet. On January 26, the total amount of contaminated square footage was 3048 square feet.

The radiation protection superintendent stated that progress in reducing contaminated square footage following RFO 7 had been slow due to the holiday season, efforts to improve plant housekeeping, and providing personnel resources for the River Bend Station refueling outage. The inspectors concluded that the current amount of contaminated areas was larger than typical nonoutage periods and that the licensee was taking actions to reduce the amount of contaminated square footage.

## 7 ONSITE REVIEW OF AN LER (92700)

(Closed) LER 382/95-001: Inability to Perform Moderator Temperature Coefficient (MTC) Testing

On March 25, 1995, the licensee was unable to perform reactor MTC testing within 7 effective full power days of reaching two-thirds of expected core burnup, as required by TS 4.1.1.3.2.c, because establishing the operating conditions of reduced power and increased cold leg temperature resulted in a pretrip alarm for the main turbine thrust bearing wear trip device. Because of the potential for a turbine trip, followed by a reactor scram, under these conditions, the licensee requested enforcement discretion from the NRC until an exigent TS amendment could be processed, which would allow the licensee to forego the MTC test for that fuel cycle only. The licensee provided the

appropriate justification, the enforcement discretion was issued, and subsequently TS Amendment 105 was approved (NRC Inspection Report 50-382/95-04).

At the time, the licensee suspected that the turbine rotor had shifted towards the main generator, in combination with an initial mispositioning of the thrust bearing, which could have caused an invalid thrust bearing wear alarm. The licensee confirmed, during a subsequent June 1995 forced outage, that adjustments to the thrust bearing made in the previous refueling outage were not properly made, in that the turning gear was not operated long enough to allow the stresses to be relieved from the turbine rotors. The licensee's engineering supervisor explained that the thrust bearing oil pressure increased exponentially, as power was decreased and steam temperature was increased, causing the thrust bearing shift from an already improper position. The turbine pretrip alarm and trip were based on bearing oil pressure.

The inspectors verified that, as committed in this LER, Maintenance Procedure MM-007-024, "Turbine Generator Thrust Bearing Inspection," was revised to include a provision to make an additional adjustment of thrust bearing position if a significant turbine rotor shift occurred during startup. With the thrust bearing properly adjusted during RFO 7, there remained sufficient margin for the establishment of plant conditions for the MTC tests for the current fuel cycle. The initial and 40 effective full power day MTC tests were completed satisfactorily without any problems. Although the two-thirds test was scheduled, there was a generic request, being processed by Combustion Engineering, to eliminate the two-thirds MTC test on the basis that, if actual boric acid concentrations in reactor coolant coincide with projected, the MTC can be extrapolated accurately without subjecting the plant to the transients involved with the MTC test at full power.

The inspectors also evaluated whether or not a violation of NRC regulations occurred, causing the need for enforcement discretion on March 25. During RFO 6, in the spring of 1994, the licensee performed work on the turbine thrust bearing. Because of the unavailability of certain parts, the bearing was assembled using old parts, resulting in greater, but acceptable, clearances than the design values. The bearing was scheduled for rework during RFO 7. These clearances, coupled with normal operating cycle wear, caused the Excessive Thrust Bearing Wear alarm to annunciate as a nuisance alarm. The licensee implemented a temporary alteration to increase the setpoint of the alarm, which, in turn, moved it closer to the turbine trip setpoint. Not having had any problems implementing the MTC test prior to 40 effective full power days at full power, the licensee had no information to indicate that the thrust bearing alarm would approach the turbine trip point so closely during the two-thirds MTC test of March 1995. The inspectors concluded that the licensee took appropriate corrective action for the nonsafety-related turbine thrust bearing problem, based on information available at the time, and that regulatory requirements were not violated.

## 8 FSAR REVIEW OF ITEMS DESCRIBED IN THE INSPECTION REPORT

A recent discovery of a licensee operating a facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with Updated Final Safety Analysis Report (UFSAR) commitments. During an approximate 2-month period, all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, procedures, and parameters.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures, and/or parameters observed by the inspectors:

- The use of an unreviewed engineering evaluation was inconsistent with engineered safety features systems allowable leakage limits described in Section 15.6.3.3.5.1.2 of the FSAR (Section 4.1).

- The actual interval between performing the integrated leak test for systems containing primary coolant outside of containment (21 months) was not consistent with Section 1.9.37 of the FSAR, which required the test to be performed at intervals not to exceed each refueling outage (Section 4.1).

## ATTACHMENT 1

## 1 PERSONS CONTACTED

### 1.1 Licensee Personnel

R. G. Azzarello, Director, Design Engineering
R. F. Burski, Director, Nuclear Safety
G. G. Davie, Quality Assurance Manager
M. Ferri, Director, Plant Modification and Construction
J. E. Glueck, Systems Engineer
J. G. Hoffpauir, Maintenance Superintendent
J. B. Holman, Manager, Safety and Engineering Analysis
J. B. Houghtaling, Technical Services Manager
J. Johnston, Senior Staff Engineer, Operational Experience Engineering
R. J. Killian, Technical Support Quality Specialist
J. J. Ledet, Security Superintendent
D. F. Litolf, Licensing Engineer
D. C. Matheny, Operations Superintendent
J. M. O'Hearn, Manager, Training
B. N. Proctor, Superintendent, System Engineering
D. L. Shipman, Planning and Scheduling Manager
R. S. Starkey, Manager, Operations and Maintenance
C. J. Thomas, Licensing Supervisor
D. W. Vinci, Licensing Manager

### 1.2 NRC Personnel

P. H. Harrell, Acting Chief, Project Branch D

The personnel listed above attended the exit meeting. In addition to these, the inspectors contacted other personnel during this inspection period.

## 2 EXIT MEETING

An exit meeting was conducted on February 12, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.