ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-382/96-03

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: February 4 through March 16, 1996

Inspectors: L. A. Keller, Senior Resident Inspector
T. W. Pruett, Resident Inspector
H. Freeman, Resident Inspector, Comanche Peak Steam Electric Station

Approved: Gregory A Pick for 4/16/96
P. H. Harrell, Acting Chief, Project Branch D — Date

Inspection Summary

Areas Inspected: Routine, announced inspection of plant operations, maintenance observations, plant support activities, onsite engineering, and followup of previously identified items.

Results:

Plant Operations

- A tour of infrequently entered radiological areas did not identify any abnormal radiological conditions; however, the inspectors did identify several rooms with inadequate lighting because of extinguished light bulbs, painted over grease fittings on the reach-rod joints for remotely operated valves, and mechanical retest tags attached to valves that were in service. The licensee established plans to address these issues (Section 2).

- Poor communications among the operations, engineering, and maintenance departments and a nonconservative assessment by the shift supervisor resulted in placing the auxiliary component cooling water (ACCW) system temperature control valve to the 50 percent manual position despite concerns regarding ACCW system operability with this valve throttled. This resulted in an inadvertent entry into the required action statements for Technical Specifications (TS) 3.7.3 and 3.7.4 for the ACCW system and the ultimate heat sink, respectively (Section 3.1).

- The emergency feedwater (EFW) steam admission valves were removed from service five times during the previous 3 years. On one occasion, the out of service period exceeded 72 hours. However, the licensee failed to perform the required TS actions because operations incorrectly assumed only one admission valve was required for operability. The failure to perform the required actions for an inoperable EFW pump is a violation of TS 3.7.1.2 (Section 5.2).

Maintenance

- The emergency diesel generator full-flow filter piston and sleeve was improperly painted. Because of binding caused by the paint, mechanical maintenance personnel were required to repeatedly strike the filter housing with a mallet to lower the filter cover. The use of a mallet to force the filter cover, rather than removing the paint, was considered a poor maintenance work practice (Section 3.2).

Engineering

- Several valves described in the emergency operating procedures for accident mitigation were not included in the inservice testing (IST) plan. This was identified as the first example of an unresolved item regarding the scope of the IST plan (Section 4.1).

- As a result of a previous NRC finding, the licensee discovered 37 additional valves that were not being tested consistent with the inservice testing design basis document (DBD). The licensee also discovered that these same discrepancies between the DBD and IST plan were identified by a pump and valve task force in November 1994, but no action was taken to evaluate/resolve the discrepancies until NRC involvement in January 1996. The failure to include these components in the IST plan and the questions regarding corrective action from the licensee's 1994 audit were identified as the second example of an unresolved item regarding the scope of the IST plan (Section 4.2).

- The initial operability assessment for 10 of the 39 valves that were not tested in accordance with the IST DBD were of poor quality because they did not sufficiently provide a basis for operability (Section 4.2).

- Stroke time testing of the EFW steam admission valves on the second cycle was an example of preconditioning. The licensee's response to the inspectors' identification of the preconditioning was adequate (Section 5.1).

- The planned actions to resolve the NRC identified precursors to EFW pump mechanical overspeed trips were adequate (Section 5.3).

- There were multiple examples of conflicting information among the Updated Final Safety Analysis Report (UFSAR), condition reports (CR), DBD, and engineering calculations for the design basis requirements for the EFW system (Section 5.6).

Summary of Inspection Findings:

New Items

- Unresolved Item 382/9603-01, Example 1: Review scope of IST Plan to determine if the appropriate manual valves have been included (Section 4.1).

- Unresolved Item 382/9603-01, Example 2: Review operability evaluations for the 39 valves in the IST plan that have not been tested (Section 4.2).

- Inspection Followup Item 382/9603-02: Review licensee's testing methodology to determine if preconditioning is occurring (Section 5.1).

- Violation 382/9603-03: Inoperable steam supply system for the turbine-driven EFW Pump (Section 5.2).

- Inspection Followup Item 382/9603-04: Review actions taken by the licensee to address EFW turbine-driven pump deficiencies (Section 5.3).

- Unresolved Item 382/9603-05: Review vendor analysis of the capability of the EFW pumps to meet the design basis requirements (Section 5.4).

- Inspection Followup Item 382/9603-06: Review the setpoint change program (Section 5.5).

- Unresolved Item 382/9603-01, Example 3: Review the scope of IST program (Section 6.2).

Closed Items

- Unresolved Item 382/9508-02 (Section 6.1).
- Apparent Violation 382/9523-03 (Section 6.2).

Attachment:

- 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, 71750)

On February 27, 1996, the inspectors performed a tour of infrequently entered radiological areas. During the tour, the inspectors did not identify any abnormal radiological conditions. However, the inspectors did identify several rooms with inadequate lighting because of extinguished light bulbs, painted over grease fittings on the reach-rod joints for remotely-operated valves, and mechanical retest tags attached to Valves CVC-183, -184, and -151B. CR 96-0273 was written to evaluate these inspection findings.

The inspectors discussed the lighting of infrequently entered radiological areas with health physics and plant management. Health physics management stated that the rooms were infrequently entered and did not require frequent replacement of extinguished light bulbs. Because some of the areas involved radiation areas in excess of 1000 mRad/hour, plant management stated that a review of the affected areas would be performed to determine if the total dose to individuals justified replacement of the light bulbs.

The inspectors discussed with the licensee the painted-over grease fittings on reach-rod joints for remotely-operated valves. The licensee stated that the reach-rod joints may not have been lubricated since initial painting of the spaces during the construction phase of the plant. The valves are located in the letdown heat exchanger and ion exchanger valve galleries and are typically only utilized during certain resin transfers and to manually isolate components in the chemical volume and control system. The licensee maintained that the failure to lubricate the valve reach-rods would not cause the valves to become inoperable. The licensee based this, in part, on valve performance history, which indicated operators could manipulate the valves.

The inspectors reviewed the emergency operating procedures and determined that the valves were not required to be operated during accident conditions; therefore, the lack of lubrication would not affect the performance of safety-related equipment required for event response.

The mechanical maintenance supervisor stated that the mechanical retests were performed but that personnel had neglected to remove the tags following retest. The inspectors reviewed the work authorizations associated with each valve and independently confirmed that the mechanical retests had been performed following the maintenance activity.

3 MAINTENANCE OBSERVATIONS (62703, 61726)

3.1 Positioning of Temperature Control Valve ACC-126A

The inspectors observed the briefing among the instrumentation and control technicians and the off-duty and on-duty shift supervisors on February 23, 1996, at approximately 10 a.m. The technicians adequately informed the shift supervisors of the maintenance and troubleshooting efforts required to determine the fault with the wet cooling tower fan sequencer. These activities included the performance of Procedure MI-005-574, "Wet Cooling Tower Basin Temperature Loop Check and Calibration," placement of Valve ACC-126A to the 50-percent position in manual control, and replacement of failed circuit cards, if necessary.

Following the briefing by the technicians, the inspectors observed the off-duty shift supervisor inform the on-duty shift supervisor of a recent concern involving the placement of the automatic controller for Valve ACC-126A to the 50-percent position in manual control, with the gagging device installed. The off-duty shift supervisor stated that system engineering should be contacted prior to placing the valve in the 50-percent position. At approximately 10:25 a.m., the inspectors observed the control room staff place the controller for Valve ACC-126A in manual and adjust the valve position to 50 percent.

At 3:05 p.m., design engineering delivered CR 96-0240 to the control room. CR 96-0240, which had been generated to request engineering to determine the appropriateness of placing Valve ACC-126A in manual, indicated that if there was a loss of instrument air pressure or a failure of Valve ACC-126A to function automatically (i.e., Valve ACC-126A was in manual control) the associated train should be declared inoperable. Under these conditions Valve ACC-126A could not perform its design basis function of automatically throttling flow during an accident to prevent excessive flow and to reduce water loss from the wet cooling tower basin. At 4:20 p.m., the licensee declared Valve ACCW-126A (ACCW Train A) inoperable and entered the required action statements for TS 3.7.3 for ACCW and TS 3.7.4 for the ultimate heat sink because Valve ACC-126A had been placed in the 50-percent position in manual control 6 hours earlier. TS 3.7.3 allows one train of ACCW to be inoperable for 72 hours, and TS 3.7.4 allows the ultimate heat sink to be inoperable for 72 hours. Since Valve ACC-126A was taken from manual control the same day, a violation of the TS action statements did not occur.

The inspectors questioned the on-duty shift supervisor to determine if system engineering had been contacted prior to placing Valve ACC-126A in manual control before performing the maintenance on the cooling tower fan sequencer. The on-duty shift supervisor stated that system engineering had not been contacted because: (1) Procedures OP-100-014, "Technical Specification Compliance" and MI-005-574 provided guidance on the placement of Valve ACC-126A to the 50-percent position, (2) Valve ACC-126A was not to be gagged at the 50-percent position, and (3) control room operators could change the valve position using the manual controller in the control room. The inspectors concluded that the shift supervisor placed too much emphasis on the distinction of gagging versus not gagging the valve and should have pursued, with more rigor, the underlying concern of the affects on the ability of the system to perform its design basis function when placing Valve-126A in manual control.

The inspectors questioned engineering to determine when the 50-percent position of Valve ACC-126A had initially become a concern. The engineer responsible for initiating the CR was unaware of the maintenance activity affecting the position of Valve ACC-126A and had been independently assigned to review how the 50-percent, manual position affected the cooling tower inventory the previous day. The system engineering mechanical superintendent acknowledged that, on February 22, he had a concern regarding the placement of Valve ACC-126A to the 50-percent position and that he was unaware that Valve ACC-126A was to be placed in the 50-percent position for the maintenance activity. Further, the engineering mechanical superintendent stated that had he known Valve ACC-126 was to be placed at the 50-percent position, he would have recommended a delay in the maintenance activity.

The inspectors determined that a weakness in communications existed among the operations, engineering, and maintenance departments in that, had the engineering department concern regarding the placement of Valve ACC-126A to the 50-percent manual position been better disseminated, the licensee may have avoided the inadvertent entry into the TS required actions for ACCW and the ultimate heat sink.

3.2 Emergency Diesel Generator Oil Filter Replacement

The inspectors observed the replacement of oil filters for Emergency Diesel Generator B on February 12, 1996, in accordance with Procedure MM-003-041, "Five Year Emergency Diesel Engine Inspection," Section 8.17, "Lube Oil Full-Flow Filter and Strainer Inspection." The inspectors observed mechanics use a mallet to repeatedly strike the lifting beam, attached to the cover plate, to lower the cover plate on to the filter housing following the replacement of filters. The use of a mallet was required since the piston used to lower the cover plate did not properly function because it had been painted. The inspectors noted that the mechanics did not attempt to remove the paint from the piston prior to, during, or following the maintenance activity.

The inspectors questioned the mechanics and determined that painting of the piston was a frequent problem. Because of the inspectors' concerns, the licensee initiated a condition identification tag to remove the paint from the piston. The inspectors determined that the use of the mallet to lower the filter cover was a poor maintenance work practice.

4 ONSITE ENGINEERING (37551)

4.1 Review of Emergency Operating Procedure Valves Against the IST Plan

The inspectors reviewed the licensee's IST plan to determine if manually operated valves described in the emergency operating procedures were included in the plan, consistent with their importance to safety. The inspectors noted that several valves required by the emergency operating procedures were not included in the IST plan. Specifically, Procedure OP-902-008, "Safety Function Recovery Procedure," required Valves SI-504 (Charging Header Crossconnect to High Pressure Safety Injection Header A Isolation), SI-505 (Charging Header Crossconnect to High Pressure Safety Injection Header B Isolation), and CVC-199 (Charging Pump Discharge to High Pressure Safety Injection Isolation) to be locally operated to fulfill the requirements of Success Path I-2, "Boration Via CVCS (Chemical Volume and Control System)." In addition to these valves, air-operated Valve CVC-209 (Charging Pump Header Isolation) was required to be closed from the control room to meet Success Path I-2. None of these valves were included in the IST plan. The licensee indicated they would perform an evaluation to determine whether the valves should be included in the IST plan, as required by Section XI, Subsection IWV of the ASME Code.

The inspectors also noted that the emergency operating procedure required Valves ACC-114 (ACCW Header to EFW Isolation), ACC-115 (ACCW Header to EFW Drain), and ACC-116 (ACCW Header to EFW Isolation) to be locally operated for alignment of the wet cooling tower basin to the suction of the EFW pumps. The inspectors determined that Valves ACC-115A and -115B were also not included in the IST plan.

As of the end of the inspection period, the licensee was still evaluating whether these valves should be included in the IST plan. This issue is identified as the first example of an unresolved item pending additional review of the licensee's evaluation by the NRC (382/9603-01).

4.2 Discrepancies Between IST DBD and IST Plan

On January 3, 1996, the inspectors identified several differences in the IST DBD and IST plan (Revision 7, Change 10) regarding the testing requirements for Valves ACC-108A and -108B (ACCW pump discharge check valves), as discussed in NRC Inspection Report 50-382/95-23. On January 15, CR 96-055 was written to disposition the lack of testing for demonstration of the capability of Valves ACC-108A and -108B to perform a safety-related function in the closed position, as stated in the DBD. On February 3, the licensee identified 37 other valves that were not being tested or were not being tested in the manner described in the DBD. As part of the root cause analysis performed for CR 96-055, an assessment of operability was performed for each of the 37 valves. As a result of this initial assessment, the licensee determined that no operability concerns existed.

The inspectors reviewed the operability assessment for the 37 valves and were concerned with the quality of the assessment prepared for 10 of the valves (EFW-2191A and -2191B, CS-118A and -118B, SI-417A and -417B, SI-120A and -120B, SI-121A and -121B) in that the assessments were based on unverified assumptions or otherwise lacked rigor. For example, the assessment for Check Valves EFW-2191A and -2191B stated, in part, that based upon the extremely low probability that a valve failure would occur concurrently with an EFW line break event, and the fact that this scenario had no significant effect on the results of Waterford's EFW system reliability analysis, it was concluded that not testing these valves had no operability impact. The inspectors observed that the low probability of a component being called upon to perform its function did not demonstrate its capability, either by testing or analysis, to complete its specified design function. As a result, the assessment provided no objective information to establish a reasonable operability basis for Valves EFW-2191A and -2191B.

Based on the inspectors' concerns, the licensee reviewed the initial operability assessment for the 37 valves and concluded that further evaluation and/or performance testing was required for Valves SI-120A and -120B, SI-121A and -121B, CS-118A and -118B, SI-417A and -417B, EFW-2191A and -2191B, and CVR-302A and -302B per Site Directive W4.101, "Operability/Qualification Confirmation Process." The inspectors reviewed the test results and additional analyses for these valves and concluded that operability was adequately demonstrated.

The root cause analysis associated with CR 96-055 also identified that the same 39 discrepancies between the DBD and IST plan were identified by a pump and valve task force in November 1994, but no action was taken to evaluate/resolve the discrepancies until NRC involvement in January 1996. The failure to include these components in the IST plan and the questions regarding corrective action from the 1994 audit are identified as a second example of an unresolved item pending further NRC review (382/9603-01).

5 EFW REVIEW (61726, 37551)

5.1 EFW TS Surveillance Implementation

The inspectors reviewed Procedure OP-903-046, "Emergency Feed Pump Operability Check," Revision 10, to verify TS Surveillance Requirement 4.7.1.2.b.2 was properly implemented. Procedure OP-903-046 implemented the aspects of Section XI of the ASME Code, as required by TS Surveillance Requirement 4.0.5.

TS 4.7.1.2.b.2 requires that EFW system operability be demonstrated by verifying that the turbine-driven EFW pump develops a discharge pressure of greater than or equal to 1342 psig on recirculation flow, when the steam generator pressure is greater than 750 psig, at least once per 92 days. The inspectors confirmed that the acceptance criteria for the turbine-driven EFW pump met these requirements.

The inspectors noted that Procedure OP-903-046 timed the opening of the steam admission valves, as required by the ASME Code, on the second start of the turbine rather than on the first. The first start of the turbine tested the mechanical overspeed trip device, and the second start timed the opening of the steam admission valves in addition to verifying the pump discharge pressure. The inspectors questioned the licensee to determine why the steam admission valves were not timed on the first start instead of the second start. The basis for the concern was that not timing the valves on the first stroke constituted preconditioning (i.e., cycling the valve prior to performing as-found testing), which could potentially mask a valve operational deficiency.

The licensee responded that, while they were not required by the ASME Code to test the valves in the as-found condition, it would be more representative to time the valves during the first start. The licensee also stated that the valves had always been timed on the second start and that this consistency would have identified trends as required by the ASME Code. The licensee stated Procedure OP-903-046 would be revised, as an enhancement, so that the steam admission valves would be tested in the as-found condition.

The inspectors determined that additional reviews of the licensee's approach to performing as-found testing would be required to determine if preconditioning was occurring. This issue will be tracked as an inspection followup item (382/9603-02).

5.2 EFW TS Implementation

During discussions with the licensee on January 11, the inspectors identified that the licensee had not correctly interpreted the TS limiting condition for operation for the EFW system. Specifically, TS 3.7.1.2 states that the EFW pumps must be capable of being powered from an operable steam supply system in order to be operable. TS Action Statement 3.7.1.2.a requires that, if one EFW pump is inoperable, the pump be restored to an operable status within 72 hours, or place the reactor in hot standby within 6 hours and in hot shutdown within the following 6 hours. Operations personnel stated that only one steam admission valve was required to be operable for the EFW turbine-driven pump to be considered operable; however, in discussions with the NRC's Office of Nuclear Reactor Regulation, it was established that both steam admission valves were required to be operable for the EFW turbine-driven pump to be considered operable.

The licensee reviewed the equipment out-of-service data base for the previous 3 years and determined that, on one occasion, a steam supply valve to the EFW pump turbine had been out of service for greater than 72 hours while the pump was required to be operable. From 2:45 p.m. on February 3, to 11:17 a.m. on February 8, 1994, (approximately 116 hours) Steam Supply Valve MS-401B was out of service for maintenance while the reactor was in Mode 1. During that time, the licensee did not declare the EFW pump inoperable and consequently did not implement the required action statement to restore the steam supply system for the EFW turbine to service within 72 hours. The inspectors determined that the failure to perform the actions required, when the turbine-driven EFW pump was inoperable, is a violation of TS 3.7.1.2 (382/9603-02).

At the request of the inspectors, the licensee reviewed the equipment out-of-service data base to determine whether either motor-driven EFW pump was out of service concurrent with one of the steam supply valves for the turbine-driven EFW pump being out of service. The licensee determined that while the reactor was in a mode that required the EFW system to be operable (Modes 1, 2, and 3), both motor-driven pumps were operable whenever one of the steam supply valves for the turbine-driven pump was inoperable.

To address the issue that some of the licensed operators considered the steam supply system was operable when steam was available from either steam generator (i.e., only one valve operable), the licensee provided clear, written guidance to the operators, which stated that if either steam supply valve to the EFW pump was inoperable, the pump was also inoperable.

5.3 Turbine-Driven EFW Pump Initiative

Recent failures of safety-related, turbine-driven EFW pumps at several facilities prompted the NRC to perform inspections at some Region IV plants. An onsite inspection was performed at Waterford 3 on August 10-11, 1995, and then, following the conclusion of in-office reviews, the findings were presented to the licensee on November 9, 1995. The results the inspection for all the plants were documented in NRC Inspection Report 50-382/95-98, dated December 1, 1995.

In that inspection, several conditions were identified with the turbine-driven EFW pump, which were the precursors to mechanical overspeed trips, that had occurred at other licensee facilities. The inspectors reviewed the licensee's actions related to these precursors, as discussed below:

- The report identified that the installation of a turbine casing steam trap allowed a small amount of water to remain in the casing, which had caused corrosion of internal components. Following a turbine run, the steam would condense into water and would remain in the casing because the height of the discharge for the steam trap was slightly above the height of the bottom of the casing.

  The licensee planned to perform a design modification to the drain line, during the next system outage scheduled for March 1996, to ensure that the casing would fully drain. The inspectors requested to review the design change but were informed by the licensee that they had not yet developed the design change.

- The report identified that the licensee had not been replenishing the turbine or governor with oil that had been prefiltered with a 5 micron filter, as recommended by the vendor.

The licensee contacted the vendor for information regarding the recommendation. The vendor informed the licensee that the recommendation was intended to help prevent clogging the system filter. The licensee replaced the system filter and scheduled replacement of the turbine and governor oil during the next system outage.

- The report identified that the licensee had not established a preventive maintenance program for the system steam traps. The licensee informed the inspectors that the vendor manual recommended that maintenance be performed on the traps annually but that they intended to establish a maintenance program on a refueling outage (18 month) basis.

  The inspectors reviewed operator logs and noted that the operators were required to open the bypass valve once per shift to drain the lines upstream of the trap. The logs required the operators to record the amount of condensate drained and to initiate a work request if the amount exceeded 2 gpm or drained for longer than 2 minutes. The inspectors were informed by an operator that less than one cup of water normally drained from the lines.

  The inspectors concluded that, while the operators could only estimate the condensate drainage, the routine observation would help to identify leaking steam admission valves and help ensure that the steam admission lines were relatively free of condensate.

- The report documented that the licensee planned to replace the installed governor valve stem with one made from a material less susceptible to corrosion. During the last refueling outage, the licensee disassembled the governor valve and noted corrosion on the stem. The licensee replaced the governor valve stem with one made from ferralium. The inspectors questioned the licensee on operating history concerning valve stems made from ferralium. The licensee stated that they did not have any history for the material but that the valve stem at another facility had recently been replaced with one made from ferralium.

  The inspectors questioned the licensee on their plans to inspect the valve stem until they had confidence that the stem material was appropriate for the operating conditions. The licensee stated that: (1) they had no plans to inspect the stem, (2) during the last refueling outage, equipment was installed to perform dynamic monitoring during turbine startup, and (3) degradation of the valve stem resulting from corrosion would be monitored. The licensee had not yet developed a specific program that included alert or increased monitoring values, but the system engineer was monitoring each start of the turbine to identify degradation.

  The licensee informed the inspectors that one of the items identified in the report was that they had not established a governor valve preventive maintenance program, as recommended by the vendor manual. The licensee stated that they intended to establish a maintenance program that would periodically determine the susceptibility of the material to corrosion.

The inspectors questioned the licensee on the priorities placed on resolving the precursors identified in the NRC report on turbine problems. The inspectors noted that, while the licensee stated that they intended to resolve the precursors, few changes had actually been completed. The licensee stated that each of the findings had been evaluated and prioritized and that none were considered an operability concern. The licensee stated that they had intended on resolving several of the items (casing drain location, prefiltered oil, preventive maintenance program, etc.) during the next scheduled system outage in March 1996, in order to minimize the system out-of-service time. The licensee stated that, while they had not performed preventive maintenance on the steam traps, the heat tracing on the steam supply lines and the compensatory measures to drain these lines ensured that the turbine was operable.

Additional reviews will be performed to verify that the licensee has taken the appropriate actions to address the conditions identified with the EFW pump turbine. Review of the licensee's corrective actions will be tracked as an inspection followup item (382/9603-04).

5.4 EFW Safety System Functional Inspection

On July 17-21 and July 31-August 4, 1995, the licensee, with the assistance of personnel from other facilities, performed a safety system functional inspection of the EFW system. The assessment team used NRC Inspection Procedure 93801, "Safety Assessment Functional Inspection (SSFI)," as guidance for the inspection. The team identified some strengths and several areas for improvement, as documented in the assessment from Mr. J. C. Roberts to Mr. R. G. Azzarello, dated August 30, 1995.

The SSFI team identified that the EFW pumps were not capable of meeting the flow/pressure requirements provided in the TS Basis Section 3/4.7.1.2, which stated that the operability of the EFW system ensured that the reactor coolant system could be cooled down to less than 350°F during a total loss-of-offsite power and that each electric-driven EFW pump was capable of delivering a total feedwater flow of 350 gpm at a pressure of 1163 psig to the entrance of the steam generators. The basis also stated that the surveillance requirement to verify the minimum pump discharge pressure on recirculation flow ensured that the pump had not degraded below that used to show that the pump met the above flow requirement.

TS 4.7.1.2 required that each motor-driven pump be tested to verify that the pump developed a discharge pressure of greater than or equal to 1298 psig on recirculation flow. The inspectors confirmed that the pump passed the periodic operability tests. Because this was a method to demonstrate operability, the pump should be able to deliver 350 gpm at a pressure of 1163 psig to the entrance of the steam generators. The SSFI team noted, from the pump curves given in Specification 1564.117, that the motor-driven pumps developed 2650 feet (1163 psig) of head at the discharge of the pump, at a flow rate of 395 gpm (350 gpm plus 45 gpm recirculation flow). This did not account for flow losses or elevation changes from the pump to the steam generator.

The SSFI team attempted to quantify the actual motor-driven pump requirements and concluded that, based on the pump curves and the system resistance curves adjusted for the lowest main steam safety valve set pressure, plus accumulation (3 percent), plus setpoint tolerance (1 percent), plus setpoint drift (1 percent) over an 18-month cycle (resulting in a discharge pressure of 1211 psig), the motor-driven pumps can provide about 280 gpm to each steam generator. This problem was documented on CR 95-0656.

The inspectors reviewed CR 95-0656, dated August 8, 1995. In the report, the licensee documented that no immediate corrective action was required because Engineering Calculation EC-S89-3 "EFW Requirements" justified that 225 gpm of EFW flow to each steam generator was sufficient to cool the reactor coolant system after a design basis event and that the TS basis requirements were unclear and should be resolved. CR 95-0656 also stated, in part, that the EFW pumps will deliver approximately 280 gpm at 1211 psig to the steam generators. The inspector noted that while the SSFI report stated that the pumps could provide 280 gpm at 1211 psig at the discharge of the pumps, the CR stated that the pumps could provide 280 gpm at 1211 psig to the steam generators. This information appeared to be contradictory.

Because of the inconsistencies noted in the various documents, the inspectors reviewed the EFW pump curves to determine motor-driven pump capabilities for various EFW flow rates. The inspectors determined the pump discharge pressure for each flow rate, which assumed a constant recirculation flow of 45 gpm, and then, from the system resistance curve, the inspectors determined the total system resistance for that particular flow rate and determined the EFW pressure at the entrance to the steam generators. The results, along with capabilities/requirements from various documents, are listed below:

Flow Rate to S/Gs (gpm)	Pump Discharge Pressure (psig)	Total System Resistance (psig)	S/G Pressure (psig)	Reference
350	1140	86	940	Inspector Independent Verification
225	1225	58	1167	Inspector Independent Verification
280	1204	71	1133	Inspector Independent Verification
350	Not Documented	Not Documented	1163	TS Basis 3/4.7.1.2

Flow Rate to S/Gs (gpm)	Pump Discharge Pressure (psig)	Total System Resistance (psig)	S/G Pressure (psig)	Reference
No Flow to S/G, Recirculation Flow (45 gpm)	1298	Not Documented	N/A	TS 4.7.1.2
280	1211	Not Documented	Not Documented	EFW SSFI Report, dated August 30, 1995
280	Not Documented	Not Documented	1211	CR 95-0656
450 plus 45 gpm recirc flow	Not Documented	Not Documented	1050	USFAR Table 10.4.9.B-1
395 plus 45 gpm recirc flow	Not Documented	Not Documented	1155	USFAR Table 10.4-12
450	Not Documented	Not Documented	1135	Section 4.1.2.1 of DBD-003

The inspectors determined that the TS basis did not appear to account for total system resistance losses and that each motor-driven pump could deliver a flow rate of 280 gpm when steam generator pressure was less than or equal to 1133 psig and not 1211 psig, as stated in CR 95-0656.

The inspectors noted that the UFSAR referenced capabilities, as shown in the above table, were based on apparent incomplete information. Specifically, UFSAR Table 10.4.9A-1 stated that it has been determined that, under realistic conditions, any one EFW pump could supply adequate flow for decay heat removal to one (400 gpm required) or both (450 gpm total required) steam generators. This was based on Engineering Calculation EC-S89-3, which determined the minimum EFW flow to prevent steam generator dryout, but did not determine steam generator pressures during the various events. From review of the pump curves, the inspector confirmed that motor-driven EFW pumps could supply sufficient flow to prevent steam generator dryout if steam pressure was less than or equal to 993 psig (400 gpm) or less than or equal to 907 psig (450 gpm).

The inspectors reviewed Engineering Calculation EC-S89-3, "EFW Requirements," dated June 29, 1990. The calculation conducted a steam generator mass balance for several different design basis events using several different flow rates. The calculation indicated that, as long as EFW flow remained above 450 gpm, water inventory would remain in the steam generators during the entire event. The inspector noted that the design basis provided in the UFSAR stated that each motor-driven EFW pump was 50 percent capacity and, therefore, in accordance with Engineering Calculation EC-S89-3, each motor-driven pump was required to deliver 225 gpm during a design basis event.

While reviewing the EFW system DBD W3-DBD-003, the inspectors noted that the document did not include any changes, even though the cover sheet indicated that the one hundred plus page document had been changed 18 times. The licensee informed the inspectors that changes were kept in separate folders in filing cabinets located in various locations on site. Changes for all documents were kept numerically by year and were separated by the various disciplines that initiated the change (i.e. electrical, mechanical, and instrument and controls). The inspectors noted that the original DBD was not annotated where changes to the DBD affected the information. The inspectors concluded that the DBD could not easily be used to verify that design changes did not affect the design basis of the system.

The licensee informed the inspectors that they were aware of the difficulties in using the DBDs and that CR 95-0099 had been written, in January 1995, to resolve the problem. The licensee reported that they had already updated 16 out of 30 DBDs and that the EFW DBD would be updated by the end of February 1996. The licensee also stated that they were revising their process to require routine updating of documents on a more timely basis.

The inspectors questioned the licensee regarding the design basis steam generator pressure that the EFW pumps must be capable of overcoming. The licensee did not know the design basis pressure and stated that they had issued a contract with a vendor to analyze and determine the EFW flow requirements.

At the end of this inspection period, the licensee had not provided the results of the analysis performed by the vendor that verified the adequacy of the EFW pumps. This issue will be tracked as an unresolved item pending NRC review of the vendor's analysis and any changes to the TS Basis (328/9603-05).

In discussions with the licensee, the inspectors established that licensee personnel consider the EFW system fully operable and capable of performing its intended design basis function. The basis for this conclusion was that a completed engineering calculation provided evidence that the EFW pumps can supply sufficient flow to both steam generators in response to all analyzed events.

5.5 Condensate Storage Pool Vortexing

The SSFI team identified that vortexing did not appear to be included as part of the original design basis for the condensate storage pool level and documented this discrepancy on CR 95-0657, dated August 8, 1995. Vortexing is a phenomenon where the pump can loose suction when pumping water from a pool as a result of cavitation.

The design basis and the TS assumed that at least 170,000 gallons of water were available to the EFW system from the condensate storage pool prior to shifting to one of the wet cooling tower basins. Based on this assumption, the TS limiting condition for operation required greater than or equal to an 82 percent level in the condensate storage pool, which equated to approximately 172,700 gallons. The licensee administratively raised the minimum level for the condensate storage pool to greater than 91 percent to account for potential vortexing, a concern that was not previously identified.

The inspectors reviewed the operator's logs and noted that the surveillance log had been modified to verify that condensate storage pool level was greater than 91 percent rather than 82 percent. However, the inspectors noted, as of January 22, 1996, the licensee had not reset the condensate storage pool low level alarm setpoint and had not submitted a TS amendment request to change the minimum required level. The inspectors reviewed the station logs and did not identify any reading less than 91 percent.

The inspectors inquired on the status of these actions. The licensee responded that the setpoint change request had been approved on January 22, 1996, and that the alarm would be reset subsequently. Additionally, the licensee stated that the amendment request package would be developed in time for the Plant Operations Review Committee meeting scheduled for April 1996.

This issue will be tracked as an inspection followup item pending additional review of the setpoint change program implemented by the licensee (382/9603-06).

6 FOLLOWUP - PLANT OPERATIONS (92901)

6.1 (Closed) Unresolved Item 382/9508-02: Review of Locked Valve Program

This issue involved a review of locked valves in response to the inspectors' identification of an improperly installed locking device on Refueling Water Storage Pool to Charging Pumps Valve CVC-504.

The inspectors randomly selected 60 components from Procedure OP-100-009, "Control of Valves and Breakers," and verified that each of the components was properly locked and in the correct position. Based on the results of this review, the inspectors concluded that the licensee was maintaining sufficient control over locked valves and breakers and no violation existed.

6.2 (Closed) Apparent Violation 382/9523-03: Failure to Perform Testing of the ACCW Pump Discharge Check Valves

This issue involved the licensee's failure to perform testing of the ACCW pump discharge check valves in accordance with the ASME Code requirements.

During review of this issue, following a predecisional enforcement conference held on March 5, 1996, it was determined that this issue would require further review and would be tracked as an unresolved issue. For tracking purposes, this issue will be followed as the third example of an unresolved item pending NRC review of the inservice testing program (382/9603-01).

7 REVIEW OF UFSAR COMMITMENTS

A recent discovery of another licensee operating a facility in a manner contrary to the UFSAR description, highlighted the need for additional verification that licensees were complying with UFSAR commitments. As a result, all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, procedures, and parameters.

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

- FSAR Tables 10.4.9B-1 and 10.4-12 specified EFW pump flow rates that were not consistent with the CRs, DBD, and engineering calculations (Section 5.4).

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

*R. E. Allen Manager, Operational and Engineering Experience
*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
*T. J. Gaudet, Supervisor, Licensing
*J. G. Hoffpauir, Maintenance Superintendent
A. Holder, Senior Engineer, Fire Protection
*J. B. Houghtaling, Technical Services Manager
*D. R. Keuter, General Manager, Plant Operations
J. M. Laque, Supervisor, System Engineering
J. J. Ledet, Security Superintendent
A. S. Lockhart, Quality Assurance Manager
*D. C. Matheny, Operations Superintendent
J. M. O'Hearn, Manager, Training
W. H. Pendergras, Shift Supervisor, Licensing
D. L. Shipman, Planning and Scheduling Manager
*R. S. Starkey, Manager, Operations and Maintenance
*D. W. Vinci, Licensing Manager

*Denotes personnel that attended the exit meeting. In addition to the above personnel, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on March 21, 1996. 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.