ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-458
License No.:	NPF-47
Report No.:	50-458/96-27
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	August 26-30 and September 9-13, 1996
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Attachment:	Partial List of Persons Contacted List of Inspection Procedures Used List of Items Opened List of Documents Reviewed

EXECUTIVE SUMMARY

River Bend Station
NRC Inspection Report 50-458/96-27

This team inspection evaluated the current effectiveness of the licensee's plant and design engineering organizations to respond to routine and reactive site activities, which included the identification and resolution of technical issues and problems. This inspection assessed engineering and technical support by focusing on the functional aspects of the 125 Vdc power system, automatic depressurization system, the standby service water system, and the station blackout diesel generator. The inspection also reviewed 50.59 safety evaluations and screenings, engineering evaluations for design modifications, and general engineering performance. The inspection covered a 4-week period with two of these weeks conducted onsite.

Engineering

- The inspection team concluded that the conduct of the licensee's engineering activities was generally effective. The team noted good progress toward improving engineering activities, especially in the plant engineering area. Plant engineers were found to be very knowledgeable of their systems, to communicate well with other plant disciplines, and to be highly qualified. The team also noted a number of past engineering issues that still needed to be addressed. These included the lack of proper load testing on the station blackout diesel generator, a failure to maintain design basis documents current since 1986, and inadequate engineering support of the preventive maintenance program.

- The licensee's installation of a portable diesel generator was an excellent initiative to mitigate the consequences of a station blackout. However, overshadowing this excellent initiative was the licensee's untimely performance of a full-load test following installation of the diesel generator. Though this diesel generator was not safety-related and was not installed to meet any regulatory requirement, the team considered the post-modification load test essential to assure that the equipment would perform its intended function (Section E1.1.1).

- The licensee was effectively implementing the permanent and temporary plant modifications processes. This was evidenced by the licensee's exemplary efforts on the main steam safety valve modifications which provided unusually leak tight valve conditions (Sections E1.1.1 and E1.1.2).

- With the exception of the inaccurate calculation for the standby service water system and the missing calculation for the station blackout diesel generator, the team found that the engineering calculations were accurate and complete (Section E1.1.7).

- The licensee had adequate implementing procedures to maintain equipment and systems that were not covered by Technical Specifications to ensure system reliability and operability. The licensee's plant planning activities included probabilistic risk assessment integration. These activities also included consideration of the affect of plant modifications on the individual plant examination model (Section E1.2).

- The licensee identified that they had not implemented the Independent Safety Engineering Group review functions as required by the Updated Safety Analysis Report. The team verified that the licensee took positive corrective actions to resolve the deficiency and accomplished the required Independent Safety Engineering Group functions (Section E1.3).

- The licensee did not address all aspects of the standby service water system upgrade. The team determined that the alarm response procedure related to starting the standby service water cooling tower fans was misleading and did not reference the applicable abnormal operating procedure or provide the operators with critical decision parameters. The team also noted that the licensee did not update standby service water system flow calculations following performance of a service water flow balance test. These discrepancies were two examples of a violation for the failure to translate design requirements into plant procedures and calculations (Section E2.1.1).

- Translation of operator actions needed to meet system design requirements were generally effective. However, the team identified that the licensee did not correctly translate throttle valve positions established in a standby service water flow balance test to an operating procedure. This discrepancy was the third example of a violation for the failure to translate design requirements into plant procedures (Section E2.1.2).

- The team found a lack of commitment by the licensee to maintain design bases documents as controlled documents since 1986. The team noted that the licensee was taking appropriate actions which, if aggressively pursued, should result in the development and maintenance of upgraded design bases documents (Section E2.1.5).

- Engineering support of preventive maintenance activities was inadequate. This was evidenced by the untimely development of preventive maintenance activities on the station blackout diesel generator, a lack of procedural detail which resulted in inappropriate reliance on "skill-of-the-craft," and a lack of preventive maintenance activities on the standby service water cooling tower fans. However, the team noted that the licensee was aware of weaknesses in their preventive maintenance program and was in process of revising the program. The team also noted that the assigned new plant engineers were taking the initiative to improve equipment maintenance activities (Section E2.2).

- The licensee had implemented effective plans to monitor and control corrosion in both the normal and standby service water systems (Section E2.3).

- The licensee was effective in controlling the backlog of engineering work by maintaining the backlog at a manageable level (Section E2.4).

- The licensee was aware of the three selected industry events and the licensee's actions to resolve the events was effective. The team considered the licensee's awareness of a very recent industry issue to be indicative of an effective industry event followup process (Section E2.5).

- Plant housekeeping and equipment material condition were considered to be excellent. This was evidenced by an absence of system leaks, an absence of debris in the plant, and an absence of material storage problems (Section E2.6).

- Engineering management expectations were clear and understood by plant engineering personnel. Communications between plant engineering and other plant departments was effective. Plant engineers were knowledgeable of their assigned systems (Section E4).

- The training program for the engineering staff was effectively supporting the role of the plant and design engineers. Particularly noteworthy was the requirement that plant engineers be certified for a specific system prior to being assigned to that system (Section E5).

- The licensee's self-assessment of plant engineering was consistent with the team's findings and was effective in identifying strengths and weakness in the plant engineering department (Section E7).

TABLE OF CONTENTS

Report Details

ENGINEERING

E1 Conduct of Engineering (37550)

E1.1 System Reviews

The team reviewed three safety-related systems to verify the licensee's ability to maintain these systems in an operable status. The three systems reviewed were the standby service water, 125 Vdc, and automatic depressurization systems. The team reviewed the adequacy of the licensee's plant modification processes (permanent and temporary), design change notices, engineering calculations, condition reports, and engineering requests. The team also reviewed the station blackout emergency diesel generator, a nonsafety-related system, that was an important addition for risk reduction.

E1.1.1 Permanent Plant Modification Review

a. Inspection Scope

The team reviewed seven permanent plant modification requests and minor modifications (listed in Attachment 1 under Plant Modifications) to verify conformance with applicable installation and testing requirements as prescribed by procedures. Specific attributes reviewed and/or verified by the team included: 10 CFR 50.59 safety evaluations, post-modification testing requirements, safety-related drawing updates, Updated Safety Analysis Report updates, training requirements, and field installation. This review also included a recent in-process modification to the decay heat removal system that, when completed, would provide an alternate decay heat removal path. The purpose of this review was to assess the quality of the licensee's current modification activities.

b. Observations and Findings

The team found that all seven permanent plant modifications had a proper 10 CFR 50.59 screening and/or safety evaluation performed and that none represented an unreviewed safety question. The team also found that, with the exception of Modification Request 93-0009 (discussed below) for the installation of the station blackout diesel generator, the described post-modification testing requirements were adequate to assure component operability. The team verified that affected drawings and procedures were updated in accordance with the modification packages. The licensee recently completed the installation of Modification Request 95-0040, that installed cross ties between the service water and standby service water systems to prevent water stagnation, and noted that the final as-built drawing revisions were not complete. The team confirmed that the control room staff had access to corrected drawings. In addition, the team verified that the physical installations of Modification Requests 93-0009, 95-0040, and 95-0057, and related field changes, were consistent with the description in the modification packages.

Modification Request 93-0009

In May 1994, Modification Request 93-0009 installed a nonsafety-related portable diesel generator that connected to Battery Charger BYS-CHGR1D. This battery charger was a back-up to both safety-related and nonsafety-related battery chargers which provided charging capability to the Division I or II 125 Vdc batteries. The purpose of this modification was to assure adequate battery charging capability under conditions in which a station blackout lasted longer than four hours. This enhanced the plant's station blackout coping capability by assuring battery charging beyond the four-hour duration requirements of Rule 10 CFR 50.63, "Loss of All Alternating Current." The licensee committed to install this portable diesel generator in a letter to the NRC, dated February 1, 1993, which submitted the licensee's individual plant examination in response to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities". Although the station blackout diesel was not safety-related, the licensee credited a reduction in core damage frequency to its installation. The licensee calculated that the addition of the station blackout diesel reduced the core damage frequency from 1.55E-5 to 1.27E-5 per year.

The team found that the post-modification testing performed in May 1994 was not adequate to prove that the diesel generator could perform its design function. Specifically, the station blackout diesel generator was not tested supplying the expected maximum station blackout loading while connected to the battery charger through a transfer switch. In response to this concern, the licensee issued Condition Report 96-1600 to identify that the post-modification test was not performed after the diesel generator's installation in 1994. As the result of their review, the licensee concluded that the original post-modification testing of the station blackout diesel generator performed under Modification Request 93-0009 was inadequate. However, the licensee also determined that the diesel generator was currently operable based on a successful full-load test performed on July 12, 1996. In addition, the licensee determined that the battery charger and the transfer switch were full-load tested individually during routine preventive maintenance tasks.

The licensee also informed the team that while these tests were conducted, they were conducted in a piece-meal fashion and not integrated such that the station blackout diesel generator was connected to the battery charger through the transfer switch under full-load conditions. In response to the condition report, the system engineer recommended that an integrated test be performed with the maximum expected load on the battery charger. The licensee assigned an action item to develop this test.

Since this diesel generator was not safety-related and was not installed to meet 10 CFR 50.63, the team considered that regulatory requirements had not been violated. Nevertheless, the licensee had implemented adequate corrective actions to resolve the concern.

Modification Request 95-0003

The team reviewed Modification Request 95-0003 which changed the disc insert in the main steam safety-relief valves to a new design flexi-disc insert and modified the nozzle and disc ring to allow installation of the new disc insert. The licensee stated that the purpose of the modification was to eliminate or reduce the amount of valve seat leakage. Prior to this modification, the licensee had a problem with seat leakage which resulted in an increase in unidentified leakage in the drywell. The modification was performed during Refueling Outage 6 at Wyle Laboratories by the valve vendor. The team found that the post-modification testing consisted of set pressure and seat leakage tests also performed at Wyle Laboratories. The seat leakage test results were zero pounds/hour steam when tested at 93 percent of set pressure. At the time of this inspection, the valves still exhibited zero leakage. The team considered the licensee's efforts to obtain and maintain zero leakage from these valves to be exemplary.

E1.1.2 Temporary Plant Modification Review

a. Inspection Scope

The team reviewed one temporary alteration and two prompt modification requests (listed in Attachment 1 under Temporary Modifications) to verify conformance with applicable installation and testing requirements as prescribed by licensee procedures. Specific attributes reviewed by the team included: 10 CFR 50.59 evaluations, post-modification testing requirements, safety-related drawing updates, training requirements, field installation, and the process for periodically reviewing the status of the modifications. The team noted that the use of prompt modification requests was the method to install temporary modifications prior to the initiation of the temporary alteration process. The team noted that there were no installed temporary modifications on the three selected systems, therefore, the team selected three that were installed on other safety-related systems.

b. Observations and Findings

The team found that the three temporary modifications had proper safety evaluations and that post-modification testing requirements were properly specified. The team also verified that the affected control room drawings were properly redlined with the change described in the modification packages. The team found that the temporary plant modifications were being tracked and that closure documents had been generated.

E1.1.3 Design Change Notice Review

a. Inspection Scope

The licensee used design change notices to revise plant drawings. To assure that these design change notices were properly implemented, the team reviewed the six design change notices listed in Attachment 1. The team verified that these notices were not used to perform plant modifications.

b. Observations and Findings

The team found that the six design change notices only changed drawings or documents and were not used to modify or change the configuration of the installed equipment. In addition, the team verified that these changes did not affect the plant's design basis.

E1.1.4 Condition Report Review

a. Inspection Scope

The licensee issued condition reports as a means to identify problems with components and systems, and to place these problems in the corrective action system for resolution. The team reviewed the 22 condition reports listed in Attachment 1 and associated with the three selected systems to determine the adequacy of the resolution, whether the systems' operability was properly determined, and whether the proposed corrective actions were adequate to preclude recurrence.

b. Observations and Findings

The team found that the condition reports had resolutions with proper engineering justification and that proposed corrective actions were adequate to preclude recurrence. The team also noted that personnel understood the condition reporting process and that personnel were not hesitant to write a condition report if an issue was identified.

The team reviewed Condition Report 96-0048 which was issued because 14 of the 16 safety-relief valve air accumulator check valves failed their leak rate test by exceeding a leakage rate of greater than 0.1 scfh. Two of the valves, which were automatic depressurization system valves, had leakage rates which exceeded 1.0 scfh. One of the valves leaked at 1.24 scfh and the other at 108.85 scfh. The team reviewed the licensee's operability evaluation for these two valves. The licensee was able to declare the valve with the lower leakage operable, but declared the other valve inoperable.

The automatic depressurization system's seven accumulators supply air to the safety-relief valves to open them when required. The accumulators were supplied air from nonsafety-related compressors and had a safety-related check valve in the line between the accumulators and the compressors to prevent back leakage. Since River Bend's first refueling outage, there have been numerous leak test failures of these check valves. The licensee investigated the valve failures and found that there was some rust particle contamination on the soft seats of some of the valves. The licensee found that a section of piping between the compressor and accumulator was carbon steel. The licensee concluded that the rust was the possible cause of valve closure failure. The licensee stated that they planned to replace the carbon steel piping and valves with stainless steel piping and valves during the next refueling outage as part of their corrective action. The licensee also stated that they would schedule replacement of the valve seats each outage since they were concerned that the soft seat material degraded due to high temperature and radiation conditions. The team noted that, as part of the licensee's corrective actions, engineering was investigating if another elastomer material would be more durable and suitable for the application.

The licensee also determined that the root cause for the check valve with the 108 scfh leakage was a loose washer caught between the valve seats which caused the seats to fail to seal. At the time of this inspection, the licensee was in the process of investigating how the washer entered the valve.

Based upon the team's review of the condition report and corrective actions, the team considered the licensee's approach and solution to this issue to be effective and thorough.

E1.1.5 Engineering Request Review

a. Inspection Scope

The licensee used engineering requests to document answers to engineering related questions. The team reviewed the five engineering requests listed in Attachment 1 and associated with the three selected systems, to determine whether these requests received proper engineering resolution. The team's review also included a determination that any questions that required plant modifications for resolution were properly identified and tracked for completion.

b. Observations and Findings

The team found that the five engineering requests had proper engineering resolutions. The team also found that none of the reviewed engineering request resolutions required the implementation of the plant modification process.

E1.1.6 Part Interchangeability Evaluation Review

a. Inspection Scope

The team reviewed the eight part interchangeability requests associated with the three selected systems and selected an additional 14 requests that were not associated with the three selected systems (listed in the Attachment 1) to verify conformance with procedures when a substitute replacement item was installed in the plant. Specifically, the team reviewed the requests to determine whether proper engineering resolution was performed and that the part interchangeability request process was not used to perform plant modifications in lieu of the plant modification process.

b. Observations and Findings

The team found that the part interchangeability requests had proper engineering resolutions and represented the proper use of replacement items as defined by the licensee's procedures.

E1.1.7 Review of Engineering Calculations

a. Inspection Scope

The team conducted a review of the 24 design engineering calculations listed in Attachment 1 and associated with the three selected systems, to determine that:

- Required technical, design verification, and independent design reviews were performed;
- Design information was correctly used for setpoint calculations;
- Calculational and analytical methodology complied with regulatory requirements, licensee design guides, licensee commitments, and industry practices;
- Calculational assumptions were technically reasonable; and,
- Open or verification-pending items in the calculations were satisfactorily resolved or properly identified and tracked for future resolution.

b. Observations and Findings

The team found that 22 of the 24 calculations were adequate. However, the team identified that the calculation for standby service water system operation with only one pump available was not consistent with the installed in-plant configuration (see Section E2.1.1 of this report for further information regarding this calculation). In addition, the team found that a calculation had not been performed to verify the sizing of the output breaker and cables between the station blackout diesel generator and the battery charger as part of Modification Request 93-0009. The team determined that without the sizing calculation, the ability of the diesel generator to perform its design function was questionable. Subsequently, the licensee performed Calculation G13.18 E-200, "Overcurrent Devices Set Points," Addendum N, and demonstrated that the breaker and cables were properly sized.

Since this calculation involved a nonsafety-related modification and was not installed to meet a license condition, the team considered that no violation of license conditions occurred.

E1.1.8 Review of Completed Maintenance

a. Inspection Scope

The team reviewed the 12 maintenance action items listed in Attachment 1 and associated with the three selected systems to determine whether the systems were being properly maintained. In addition, the team's review determined if these maintenance activities resulted in modifications to plant systems.

b. Observations and Findings

The team found that the systems were being properly maintained, that no adverse performance trends due to maintenance activities were identified, and that no unauthorized modifications were performed as the result of these activities.

E1.1.9 Conclusions on System Reviews

The team concluded that the licensee was effective in assuring that the three selected systems were maintained in an operable status. The permanent and temporary plant modification processes were effectively implemented. This was particularly evidenced by the main steam safety valve modifications which provided unusually tight valve conditions. With the exception of the calculations for the standby service water system and the station blackout diesel generator, the team also considered the engineering calculations to be accurate and complete.

The licensee's installation of a portable diesel generator was considered to be an excellent initiative to mitigate the consequences of a station blackout. However, this was overshadowed by the licensee's untimely performance of a full-load test following installation of the diesel generator. Though this diesel generator was not safety-related and was not installed to meet any regulatory requirement, the team considered the post-modification load test essential to assure that the equipment would perform its intended function.

E1.2 Surveillance of non-Technical Specification Equipment and Engineering Use of Probability Risk Assessments

a. Inspection Scope

The team did not review surveillance testing for the three selected systems because this area had recently been extensively reviewed by the resident staff. However, the team did review applicable surveillance test procedures to verify that the licensee was maintaining equipment for systems that were not covered by Technical Specifications to ensure system reliability and operability. This included equipment for station blackout and the safety parameter display system. The team also reviewed the licensee's integration of probalilistic risk assessment into plant planning activities.

b. Observations and Findings

The team noted that the licensee implemented adequate surveillance procedures to ensure that the operability of equipment installed in accordance with NRC regulations, but not specifically identified in the Technical Specifications. In addition, the team noted that Procedure EDP-AA-80, "Modification Forms," provided instructions pertaining to design and modifications and contained a modification request checklist with a mandatory requirement ensuring that probabilistic risk assessment was considered in the coordination of plant work. The team's reviews of the plant modifications listed in Attachment 1, indicated that probabilistic risk assessments were evaluated for potential impact on the individual plant examination models for the applicable systems.

c. Conclusions

The team concluded that the licensee had adequate implementing procedures to maintain such equipment and systems that were not covered by Technical Specifications to ensure system reliability and operability. The team concluded that the licensee's probabilistic risk assessment was effectively integrated into plant planning activities and changes to the risk assessment due to plant modifications were considered for their affect on the individual plant examination model.

E1.3 Independent Safety Evaluation Group

a. Inspection Scope

The team evaluated the overall effectiveness of the Independent Safety Engineering Group by interviewing one safety engineer, by reviewing the qualifications of three safety engineers performing the quality technical reviews, by reviewing Independent Safety Engineering Group reports, and by verifying that Independent Safety Engineering Group finding corrective actions were properly implemented.

b. Observations and Findings

The team noted that NRC Inspection Report 50-458/96-21, dated August 22, 1996, documented that Condition Report 96-1024, issued on June 6, 1996, identified that the Independent Safety Engineering Group was not in compliance with the Updated Safety Analysis Report and the Technical Requirements Manual. In this condition report, the licensee identified that the procedures for the performance of the Independent Safety Engineering Group functions did not reflect current practices (see NRC Inspection Report 50-458/96-21 for further details regarding this issue). The team also noted that the corrective actions for this condition report were on schedule toward resolution with a completion date of September 30, 1996. The team verified that the Independent Safety Engineering Group functions were being performed in the interim through distribution among existing groups within the Nuclear Safety and Regulatory Affairs Department and the Quality Programs Department. The team's review of the qualifications of the safety engineers performing the Independent Safety Engineering Group functions indicated that they were consistent with the Updated Safety Analysis Report requirements.

c. Conclusions

Although the licensee had not implemented the Independent Safety Engineering Group review functions as required by the Updated Safety Analysis Report, this issue had been previously identified by the licensee and corrective actions were being taken to resolve the deficiency. In addition, the team verified that the required Independent Safety Engineering Group functions were being accomplished in the interim.

E2 Engineering Support of Facilities and Equipment (37550)

E2.1 Facility Conformance to License Conditions and Design Basis Documents

E2.1.1 Conformance to the Updated Safety Analysis Report

a. Inspection Scope

A recent discovery of a licensee operating its facility in a manner contrary to the Updated Safety Analysis Report description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the Updated Safety Analysis Report description. While performing the inspections discussed in this report, the inspectors reviewed the applicable sections of the Final Safety Analysis Report that related to the selected plant systems.

The team reviewed Section 7.3.1.1.1.2, "Automatic Depressurization System", Section 8.3.2, "DC Power Systems", and Section 9.2, "Water Systems" of the Updated Safety Analysis Report. The team also interviewed licensee personnel, reviewed plant procedures, and conducted plant tours to determine if the in-plant systems were consistent with the descriptions in the Updated Safety Analysis Report.

b. Observations and Findings

The team found no discrepancies between the Updated Safety Analysis Report and the actual plant configuration for the 125 Vdc and the automatic depressurization systems. However, during review of the Updated Safety Analysis Report and the actual plant configuration for the standby service water system, the team found that one operator action described in the Updated Safety Analysis Report was not directly translated into the appropriate abnormal operating procedure and that a calculation was not updated to reflect the latest flow balance test results.

In Updated Safety Analysis Report Section 9.2.7.3, the licensee evaluated the loss of the Division III emergency power supply. The Updated Safety Analysis Report stated that, due to the loss of Division III power, operator action was required after 20 minutes to permit cooling of two residual heat removal heat exchanger trains. The team noted that since one of the two pumps on the "A" subsystem was powered from the Division III power supply, loss of the Division III power supply resulted in single pump operation on the "A" subsystem. Because of this reduction in flow capacity, the Updated Safety Analysis Report further stated that operator action would be required to limit flow demands on this pump by re-aligning the system to limit flow to only the following equipment:

- Residual Heat Removal Heat Exchanger Train A;
- Residual Heat Removal Pump Cooler;
- Auxiliary Building Unit Coolers; and
- Standby Diesel Generator A.

The team reviewed Abnormal Operating Procedure AOP-0004, "Loss of Offsite Power," Revision 11B, to determine if these loading restrictions for the "A" subsystem were implemented in the portion of the procedure which addressed the loss of Division III power. The team found that Step 5.4.2 instructed the operators to reduce the "A" subsystem standby service water loads when Division III power fails. However, the procedure also instructed operators to leave the Division I containment unit cooler in service in addition to the loads listed in the Updated Safety Analysis Report.

The licensee initiated Condition Report 96-1636 to address this deficiency. The licensee performed an operability determination and concluded that even with the additional flow requirements for the Division I containment unit cooler the total flow requirements for the subsystem would not exceed the pump runout values. Based on design values the licensee estimated that the total flow requirements for the subsystem would be 8129 gpm. The pump vendor provided documentation that the pump was capable of producing 9600 gpm indefinitely. The team noted that the design value for the pump was 7600 gpm at 170 feet of head. The licensee provided Calculation 12210-PM-236, "Standby Service Water Operation with One Pump Available," dated April 12, 1985, to demonstrate that the configuration described in AOP-0004 was previously analyzed to ensure that the subsystem could be operated without exceeding pump runout.

During further review, the team noted that since 1985, the system resistance values used in Calculation 12210-PM-236, to model performance of the standby service water system, had changed for several reasons. In 1992, the licensee performed extensive cleaning of both the standby service water and the normal service water systems. Furthermore, the licensee modified the service water system in 1992 to be a closed cycle system rather than an open cycle system. Following the modification and cleaning activities, the licensee performed Procedure TP-92-008, "Flow Balance and Design Flow Verification for the Standby Service Water System and the Normal Service Water System," Revision 0. The throttle valve adjustments made during this test affected system resistance. The team found that Calculation 12210-PM-236 was not updated and, therefore, was no longer accurate.

10 CFR 50, Appendix B, Criterion III, requires, in part, that design control measures, such as a testing program, provide for verifying the adequacy of design and that any design changes from this testing program be implemented consistent with the design controls applied to the original design. The team found that Calculation 12210-PM-236, which provided the analytical basis for single pump operation of the "A" subsystem of standby service water following a loss of the Division III diesel generator, had not been updated to reflect system modifications and the throttle valve positions established during the August 1992 performance of the flow balance test conducted in accordance with Procedure TP-92-008. The failure to update Calculation 12210-PM-236 was the first example of a violation of 10 CFR 50, Appendix B, Criterion III (50-458/9627-01).

The team discussed this finding with the licensee and learned that the licensee was aware that this calculation should be voided and that other calculations required updating. The licensee explained that as a corrective action for a 1995 condition report, they obtained contractor support to review their service water system analysis. The contractor identified that Calculation 12210-PM-236 should be voided. The licensee stated that they previously prioritized all of the incorrect calculations for updating and that Calculation 12210-PM-236 was scheduled for revision by October 28, 1996. However, the team noted that calculation 12210-PM-236 was not voided at the time of this inspection.

During further review, the team also noted that starting the standby cooling tower fans was one of the critical operator actions for mitigating risk. The team reviewed Alarm Response Procedure ARP-870-55, "P870-55 Alarm Response," Revision 6B, Alarm No. 0658, "STBY SERVICE WTR COOLING TOWER HIGH TEMP." This alarm initiated when the standby cooling tower basin temperature exceeded 84° Fahrenheit.

The team noted that the procedure for responding to Alarm 0658 instructed the operators to start either a Division I or Division II standby service water pump and fans as necessary to lower standby service water cooling tower basin temperature. The alarm response procedure included a precautionary note that stated that during a loss of offsite power concurrent with a loss of coolant accident, that the standby service water cooling tower fans should not be started until two hours after the initiation of the loss of coolant accident event. The team found that this note conflicted with a similar note in procedure AOP-0004. Procedure AOP-0004 cautioned the operators to place the fans in service within two hours after the loss of coolant accident event.

The team discussed this conflict with the license to understand the technical basis for the caution. The team found that it was necessary for the operators to start the standby cooling tower fans within two hours to prevent the service water system from exceeding the peak temperature assumed in the containment analysis. In addition, based upon the emergency diesel generator loading analysis described in the Updated Safety Analysis Report, the team found that it was necessary to secure other electrical loads prior to starting the standby cooling tower fans to prevent overloading the emergency diesel generator. This two-hour limit was based on the assumption that other post-accident electrical loads could be secured after two hours into the accident scenario.

The team noted that the abnormal operating procedure included cautions to address both the standby service water system heatup issue and the emergency diesel generator loading issue. However, the team determined that the alarm response procedure caution was misleading, in that, it did not reference the abnormal operating procedure or adequately provide the operators with critical decision parameters. Alarm Response Procedure ARP-870-55 did not correctly translate the requirement that operators secure other electrical loads as necessary to ensure adequate emergency diesel generator loading margin prior to starting the standby cooling tower fans and did not correctly translate the requirement to start the standby cooling tower fans within two hours. The licensee subsequently revised the alarm response procedure by removing the caution and referencing the abnormal operating procedure.

10 CFR Part 50, Appendix B, Criterion III, requires that plant design bases be properly translated into procedures. The failure to adequately translate the design basis for successful operation of the standby cooling tower fans into the alarm response procedure is the second example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-458/9627-01).

E2.1.2 <u>Conformance to the Design Basis Flow Balance Test</u>

a. <u>Inspection Scope</u>

The team reviewed System Operating Procedure SOP-0018, "Normal Service Water (SYS #118)," Revision 17, to determine whether the throttle valve positions specified in the system operating procedure were consistent with the throttle valve positions that were established in the design basis flow balance test conducted in accordance with Test Procedure TP-92-008.

b. Observations and Findings

The service water system was comprised of the normal service water system and the standby service water system. The normal system was routinely in service and supplied all service water system loads, both safety-related and nonsafety-related. The system was designed so that upon loss of normal service water or upon loss of reactor plant component cooling water, valves in the service water system supply and return header would automatically close to separate the safety-related standby service water system from the nonsafety-related normal service water system. The system was designed so that the portion of the system which supplied safety-related loads would be supplied by the standby service water system, which drew water from the standby cooling tower basin ultimate heat sink.

The team compared a sampling of throttle valve positions determined from performance of Test Procedure TP-92-008 with the throttle valve positions specified in Procedure SOP-0018. The team identified ten valves which were positioned by the system operating procedure that were different from the valve positions determined by the flow balance test results.

As a result of the team's findings, the licensee initiated Condition Report 96-1644. As an immediate corrective action the licensee performed a complete comparison between the throttle valve positions determined in the flow balance test and the valve positions specified in the system operating procedure. The licensee evaluated the throttle valve position deviations and determined that the service water system was operable as currently configured by the system operating procedure.

The team noted that the flow balance test was conducted in four parts. The first two parts established the flow balance for Division I and Division II of the safety-related standby service water system. The third part established the flow balance for the normal service water system with only a single pump operating, assuming safety-related and nonsafety-related loads were in service. The fourth part established the flow balance for the normal service water system with two pumps operating, also assuming safety-related and nonsafety-related loads were in service.

The team noted that the throttle valve positions established during the normal service water system flow balance (i.e., parts three and four) affected the flow balance of the safety-related standby service water system. The team learned that during the 1992 testing, the normal service water portions of the flow balance were performed after the standby service water portions of the flow balance were completed. The team noted that the licensee used the final throttle valve positions established during the normal service water system flow balances to develop the system operating procedure.

The team requested that the licensee compare the throttle valve positions established for the Division I and Division II of the standby service water system with the system operating procedure. As a result of this comparison, the licensee identified additional throttle valve position deviations. The licensee also evaluated these deviations and determined the system was operable as configured by the system operating procedure. The team reviewed the licensee's operability evaluation and concurred that the licensee's engineering judgement was reasonable and provided a basis for continued operation while further analyses were performed.

Based on review of the flow balance test and the system operating procedure, the team concluded that the licensee had not correctly translated the throttle valve positions established in the standby service water system flow balance test to the operating procedure.

Title 10, CFR 50, Appendix B, Criterion III, requires that measures shall be established to assure that the design basis is correctly translated into procedures. The failure to translate the valve throttle positions established in the August 1992 flow balance test into Procedure SOP-0018 was the third example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-458/9627-01).

E2.1.3 Conformance to General Design Criterion 2

a. Inspection Scope

The team toured the standby service water cooling tower basin structure and pump rooms, reviewed architectural drawings, reviewed flow calculations, and reviewed the licensee's engineering evaluation to determine if they were in compliance with General Design Criterion 2. The team also reviewed engineering evaluations related to objects which had been dropped into the cooling tower basin.

b. Observations and Findings

The standby service water cooling tower functions as the ultimate heat sink for the plant to dissipate residual heat after shutdown or following an accident. The tower structure has four side air inlet openings (12 X 54 feet), and one large center air exhaust opening in the top (54 X 54 feet), for the 20 cooling tower fans. The team noted that these large openings do not have any protective screens or other barrier to prevent wind blown debris from entering the cooling tower basin during events such as tornados or hurricanes.

In addition, the team noted that the deep draft standby service water pump suctions did not have any screens or protective coverings to prevent debris from entering the pump suction if the wind blown debris or any object accidentally dropped into the pool approaches the vicinity of the pump suction volute. The team considered that it was possible for wind blown debris to enter the cooling tower basin, sink to the bottom of the basin, and potentially clog the standby service water pump suctions.

The team found that the licensee experienced three events where objects were dropped into the cooling tower basin. In each case, a condition report was written and evaluated. These evaluations covered three single objects (a metal wedge, a large bolt, and a pool skimming net). The licensee calculated that the initial standby service water flow velocities were insufficient to overcome the drag characteristics exhibited by these objects and, therefore, concluded that these objects would not enter the pump suctions.

The team noted that while the licensee's conclusions were conservative, they were only appropriate for the specific conditions noted in the condition reports. The team was concerned that other objects of different size and buoyancy could possibly enter the pool and be drawn into the pump suction. The team requested that the licensee determine if any situation could occur which would potentially render the standby service water pumps inoperable.

The licensee provided an analysis of the potential for wind blown debris to enter the cooling tower basin and be drawn into the suction of the standby service water pumps. The licensee determined that the flow velocities were too slow for debris of any buoyancy to be swept into the pump suctions. Based on a review of the surrounding areas, the licensee also determined that there was not a reasonable potential for debris to be introduced into the basin. The licensee also informed the team that personnel access to portions of the basin was limited.

The team noted that the licensee's analysis depended on the assumption that basin levels were high. Low basin levels are expected several days into an accident. As basin levels drop during an event, the flow velocities to the pump suction increase. The team and the licensee agreed that at low basin levels the flow rates would be high enough to carry near buoyant debris into the suction of the pumps.

The licensee stated that they were not required to design for a full 30 day mission time and that they were only required to evaluate for a tornado induced loss of offsite power. During a loss of offsite power event the standby service water pumps would continue to run while the normal service water pumps would be lost. The licensee determined, that this event would only last five days and, therefore, the basin levels would not get low enough for the debris to be swept into the pump suction. Based on a review of Electrical Power Research Institute data regarding the probability and duration of loss of offsite power events, the licensee reasoned that it was likely that power would be restored, normal service water would be returned to service and, as a result, debris would not be swept into the suction of the pumps. They also reasoned that if power were not restored for several days they would have time to clean out the basin before the pump suctions would become clogged.

The team noted that the licensee's position was that a lack of debris in the immediate vicinity of the cooling tower was a basis for concluding that there was no reasonable potential for debris to be introduced into the cooling tower basin by a tornado. This was inconsistent with the team's position that since tornados frequently carry debris for long distances, the potential existed that this carried debris could be deposited into the cooling tower basin. However, based on a review of the architectural drawings, the licensee's flow analysis and the Electrical Power Research Institute data, the team agreed that the licensee would have several days before debris would be swept into the suction of the pumps. The team agreed that the issue was not an operability concern.

The licensee also provided information that the original licensing basis for the structure was based on the analysis of a prescribed set of potential missiles. The prescribed set of potential missiles were all heavy, non-buoyant, objects which would not be swept into the pump suctions. The team agreed that, with respect to this prescribed set of missiles, the current configuration adequately protected the structures, systems, and components for the full 30 day mission of the standby service water system. The team concluded that the structure met the original licensing requirements.

The team determined that the standby service water system was not protected from tornado generated near buoyant debris for the full 30 day mission of the standby service water system. The team also determined that other facilities with cooling towers of this type may be vulnerable to debris entering the cooling towers. This issue will be forwarded to the Office of Nuclear Reactor Regulation so that this vulnerability can be reviewed from a generic aspect. This item is considered to be Inspection Followup Item (50-458/9627-02) pending completion of the Office of Nuclear Reactor Regulation review.

E2.1.4 Validity and Control of Design Basis Documents

a. Inspection Scope

The team reviewed the licensee's controls of design basis documents to determine if the documents were available, were being maintained, and were easily retrievable.

b. Observations and Findings

The team found that the licensee utilized system design requirements documents for guidance in obtaining design basis information for most major systems. System design requirements documents were meant to provide an overview of the system and a reference to related design basis documents, calculations, and drawings. However, the system design requirements documents were not considered design basis documents and were not maintained, updated, or validated as such. The licensee initiated Condition Report 95-0057 on January 17, 1995, to address this situation. This condition report stated that the existing system design requirements were not maintained as controlled documents since their origination in 1986, and that they were used as "for information only" roadmaps to obtain design information.

The licensee implemented "Specification for SDRD Upgrade Project," Revision 1, dated March 11, 1996, to convert system design requirements documents to a new document called the system design criteria document as part of a 1995 pilot program. This pilot program was developing system design criteria documents for the low pressure core spray system and the 125 Vdc system. These documents would update and validate the system design so that it conformed to the system's design basis. The licensee informed the team that the 1995 pilot program was scheduled for completion by November 1996, and that 19 additional systems were scheduled for completion by December 20, 1997. The licensee also informed the team that the selection of the systems for development of the system design criteria was based upon system importance to core damage frequency. The team noted that the licensee was revising their system design criteria procedure so that the new system design criteria documents would be maintained current. The team also noted that the licensee included maintenance of the design basis documents as part of their long term performance improvement plan.

The team was also informed by the licensee that the original design basis documents were available on site, but were not easily retrievable. Team interviews with system and design engineers revealed that obtaining design basis documents was not only a challenge, but also had a high potential to miss some design documents. However, the team did not identify any instances where document retrieval was not accomplished.

E2.1.5 Conclusions on Facility Conformance to License Conditions and Design Basis Documents

While the licensee upgraded the design basis for the standby service water system, not all aspects of the upgrade were properly addressed. The team determined that the alarm response procedure related to starting the standby cooling tower fans was misleading and did not reference the abnormal operating procedure or adequately provide the operators with critical decision parameters. The team also noted that the licensee did not update standby service water flow calculations following performance of the standby service water flow balance test.

Operator actions needed to meet system design requirements were generally translated into operations procedures. However, the team identified that the licensee did not correctly translate throttle valve positions established in the standby service water flow balance test into an operating procedure.

The team concluded that the standby cooling tower was designed in accordance with the original license basis requirements.

The licensee's system design requirements documents were inadequate because they were not maintained as controlled documents since 1986. The team noted that the licensee was taking appropriate actions which should result in the development and maintenance of upgraded design bases documents.

E2.2 Preventive Maintenance Procedure Review

a. Inspection Scope

The team reviewed the preventive maintenance activities for the station blackout diesel generator and the standby service water cooling tower fans to determine engineering involvement in assuring that this plant equipment was being properly maintained.

b. Observations and Findings

The team found from a review of the preventive maintenance procedures associated with the station blackout diesel generator that Preventive Maintenance Task Instruction EL13212-03, "BYS-EG1," Revision 0, had a lack of procedural detail which resulted in excessive reliance on the "skill-of-the-craft." Specifically, Section 9.5 required that the technician use a clamp-on ampere meter to verify that both the engine coolant heater and the generator space heater were working. The team noted through observation and interviews with maintenance personnel that the instructions were insufficient to properly determine the correct location for use of the clamp-on ampere meter and that reliance on "skill-of-the-craft" to locate the meter was inappropriate. The licensee agreed with this observation, and stated that this instruction would be revised.

The team also noted that the station blackout diesel generator was installed in May 1994; however, it was not included in the preventive maintenance program until January 1996. In addition, the team found that a full-load test of the diesel generator was not conducted until July, 1996. The team noted that the newly assigned plant engineer recognized the need to perform a full-load test of the diesel generator and took the initiative to obtain the necessary equipment to perform such a test (the equipment was not previously available). In addition, the plant engineer determined that a full-load test should be conducted on a monthly basis. This test was incorporated into the preventive maintenance program and the licensee was in process of obtaining the necessary test equipment.

In October 1994, the licensee determined that vendor recommended preventive maintenance activities were not performed on the standby cooling tower fans since commencement of plant operations. These activities included motor bearing greasing, fan inspection, and fan vibration testing. An initial operability determination, based on engineering judgement, was performed to verify operability. With the subsequent assignment of a new plant engineer to the system, steps were taken to more thoroughly assess the condition of the fans. The licensee sampled grease from one fan and had the grease analyzed on June 12, 1995. Based on the results of this grease analysis, an examination of fan motor running current trends, and physical observation of fan performance, the licensee concluded that the fans were operable.

The licensee informed the team that maintenance activities were initially not performed because the fan motors were generally inaccessible due to their location in the cooling tower structure. The licensee also informed the team that they recognized weaknesses in their preventive maintenance program and initiated a condition report to address generic preventive maintenance program issues.

The team reviewed the corrective actions recommended by the licensee and determined that they were generally acceptable. However, the team noted that as of September 13, 1996, the preventive maintenance activities on the standby service water cooling tower fans were not yet performed. The licensee stated that they expected to perform the preventive maintenance activities for the standby cooling tower fans by October 1, 1996.

c. Conclusions

Based upon the results of this inspection, the team concluded that the licensee had provided inadequate engineering support of preventive maintenance activities. This inadequacy was evidenced by the untimely preventive maintenance activities on the station blackout diesel generator, an inappropriate reliance on "skill-of-the-craft," and a lack of preventive maintenance activity on the standby service water cooling tower fans. The team noted, however, that the licensee was aware of weaknesses in their preventive maintenance program and was in process of revising the program. The team also noted that the assigned new plant engineers were taking the initiative to improve equipment maintenance activities.

E2.3 Service Water System Corrosion Control

a. Inspection Scope

The team reviewed the licensee's program for maintaining the service water system piping free of corrosion. This review included interviews of chemistry personnel, a review of recent chemical monitoring results and corrosion monitoring test methods, and a review of schedules and plans for improving corrosion controls for the service water system.

The team also reviewed Modification Request 95-0040, "Install Cross Ties to Prevent Water Stagnation," that was developed to reduce the amount of water stagnation in the standby service water system. The team also reviewed the ultrasonic test plans developed to monitor corrosion in the service water system.

b. Observations and Findings

The normal service water system is a closed system which circulates treated water through both safety-related and nonsafety-related portions of the system during normal operations. The licensee stated that water in the normal service water system is treated with multiple chemicals to inhibit carbon steel and copper corrosion. The system also contained biocides for microbiological control. The licensee stated that they use a coupon rack to monitor the effectiveness of the corrosion inhibitors. They routinely check coupon specimens to determine if adequate chemicals are present in the system.

The team reviewed recent chemistry data compiled from this monitoring program and had no concerns. The program appeared to be a very comprehensive effort for controlling corrosion in the majority of the service water system. The team also noted that the program was recognized by Electric Power Research Institute as a state-of-the-art methodology for controlling water chemistry in closed-loop cooling systems.

The team also noted that portions of the standby service water piping were isolated from the normal service water system and, hence, water treatment during normal operation. Although a bypass line was added in 1996 to circulate a small amount of treated water through some of the idle piping, approximately 100 feet of 30" piping from the discharge of the Standby Service Water Pumps (SWP-2A, 2B, 2C, and 2D) remained isolated from the chemical treatment and corrosion monitoring system. The licensee stated that this piping did contain residual chemicals but was not being monitored on a routine basis.

During the inspection, the licensee completed their plans for re-instituting an ultrasonic testing program for various sections of service water system. The team reviewed the plans and found that the licensee intended to perform routine ultrasonic testing to monitor corrosion in the portions of the standby service water system piping that were not being chemically treated during normal operation.

c. Conclusions

The team concluded that licensee had plans in place to effectively monitor and control corrosion in both the normal and standby service water systems. In general, the team found that the licensee had effectively developed plans to resolve service water system issues. Although the team was initially concerned that the licensee had not fully developed corrosion monitoring plans for the dead legs in the standby service water system, the licensee completed the corrosion monitoring plans for this piping during the inspection.

E2.4 Engineering Work Backlog

a. Inspection Scope

The team evaluated the extent of backlogged engineering work to determine the size of the backlog and to determine whether it was being properly managed.

b. Observations and Findings

The team found that the engineering backlog consisted of 46 condition report dispositions, 439 corrective actions, 309 modification requests, 90 engineering requests, 336 drawing requests, 13 engineering evaluation and assistance requests, and 39 vendor technical information reviews. In reviewing the open backlog items the team found the following:

- Condition report dispositions had decreased from 110 in July 1995 to approximately 46 in August of 1996.

- Condition reports not dispositioned within 90 days had decreased from 55 in July 1995 to approximately 3 in August 1996.

- Corrective actions had decreased from 522 in July 1995 to 439 in July of 1996. However, the team observed that this backlog was 412 in January 1996 and has been relatively constant over the past 6 months. The team determined that the backlog of corrective actions had remained constant because of the increase in condition reports associated with the January 1996 refueling outage followed by two forced outages in June and July. The licensee stated that this increase in corrective actions associated with condition reports was a normal expectation during outages. The licensee's goal was to maintain the corrective action backlog at less that 250. To achieve that goal, the licensee brought in contractors to assist in reducing the number of engineering open corrective actions.

c. Conclusions

The team concluded that the licensee was effectively managing the backlog of engineering work.

E2.5 Resolution of Recent Plant Events

a. Inspection Scope

The team reviewed documentation and interviewed two personnel from the operating events group to determine if the licensee was aware of and had taken action regarding three recent industry events. The first event involved multiple failures of the General Electric 4.16 kV Magna-Blast circuit breakers to latch closed (i.e., fail to stay closed after the closure signal was received) that occurred at the Salem nuclear plant on May 3, 1996. The second event involved zinc coating of hardened internal circuit breaker parts during refurbishment by non-original equipment manufacturer vendors which also occurred at the Salem nuclear plant on

June 5, 1996. The third event involved the potential for the failure of the reactor water cleanup system to automatically isolate following a high energy line break located outside of the drywell. This issue was identified at the Monticello nuclear plant on August 13, 1996.

b. Observations and Findings

Magna-Blast Circuit Breaker Latching Failures

During the performance of a surveillance test of the high pressure core spray pump on June 27, 1995, the licensee noted that the circuit breaker for this pump failed to latch closed. Condition Report 95-0662 was issued and corrective actions were assigned to resolve this failure. Repeated circuit breaker testing by the licensee could not duplicate this failure. In addition, a search of industry experience only identified a circuit breaker latching problem that involved prop spring mounting caused by a loose bolted connection. The circuit breaker was checked for this condition and it was found that this condition did not exist for this circuit breaker. As the result of these activities, the licensee considered the circuit breaker to be operable. However, since this failure could not be identified, the licensee also planned to replace the breaker during the next outage and sent the breaker to a vendor for further evaluation. This replacement was accomplished on August 23, 1995, and the removed circuit breaker was sent to a vendor for further evaluation with a planned completion date of December 30, 1995. During the licensee's review of the vendor's evaluation on or about February 27, 1996, the operating events group became aware of a manufacturer's (General Electric) Service Advisory Letter, 352.1, that was issued on July 7, 1995. As the result of this discovery, the licensee requested and obtained this letter from General Electric on February 27.

Following receipt of this letter, the licensee determined that their Magna-Blast circuit breakers were not refurbished in accordance with information provided by this letter. As the result of this finding, the licensee issued Condition Report 96-0567 to identify the failure to obtain the service advisory letter. In addition, an Operating Experience Statement of Action, issued on March 22, 1996, requested engineering to address this issue by May 22. On approximately May 13, 1996, the licensee was informed of the Magna-Blast circuit breaker problem at the Salem nuclear plant and placed the event on their electronic mail system for engineering review. The Salem event occurred as the result of the failure to incorporate the suggested actions in Service Advisory Letter 352.1. Engineering responded to the March 22 Operating Experience Statement of Action on May 15 and stated that the actions recommended in the service advisory letter would be taken at the next scheduled maintenance period to correct the issue for each applicable circuit breaker. The team considered engineering's response to this event to be timely and effective.

Improper Coating of Circuit Breaker Parts By Vendors

The operating events group received notice of the second event on June 5, 1996. In this event, circuit breakers were refurbished with hardened parts that were improperly coated with a zinc coating by non-original equipment manufacturer vendors. During the evaluation of this operating experience report, the licensee determined that only one of their circuit breakers was refurbished by a non-original equipment manufacturer vendor with hardened parts that were zinc coated. The circuit breaker involved was the same high pressure core spray pump circuit breaker identified in the previous paragraph. This circuit breaker was refurbished but was not installed and was stored in the warehouse as a spare. The licensee immediately placed a hold on usage of this circuit breaker pending a new refurbishment by the vendor. The team considered engineering's response to this event to be timely and effective.

Reactor Water Cleanup System Isolation Failure

The operating events group received notice of the third event involving the reactor water cleanup system potential failure to isolate on Tuesday, August 27, 1996. This information was placed on their electronic mail system with the normally specified seven day response window. The team interviewed the system engineer involved with the plant's leak detection systems to determine if this event was applicable to the River Bend plant. The engineer stated that this event was only applicable to older BWR 3 and 4s and was not applicable to River Bend, a BWR 6, because these plants have additional isolation signals for the reactor water cleanup system.

The team's review of this issue indicated that BWR 3 and 4s only had two actuation signals for reactor water cleanup isolation, low reactor water level and high drywell pressure. Since the postulated break occurred outside of the drywell, no isolation would occur from the high drywell pressure signal. At lower power levels (i.e., less than 90 percent of full power), the feedwater system would compensate for the reactor water cleanup system break and prevent the reactor vessel water level from reaching the low level isolation point. As the result, the system would not isolate for some time causing a large release of reactor water outside of the containment. The BWR 6s, however, had two additional isolation signals. One signal was generated by high temperatures in the rooms housing the reactor water cleanup system and the other signal was generated by measuring and comparing the flow of water into the reactor with the flow of water out of the reactor. A break at any power level would cause one or both of these signals to isolate the reactor water cleanup system.

c. Conclusions

The team found the licensee to be aware of all three of these industry events and their actions to be effective. The team also noted that the licensee was aware of very recent industry issues. The team considered the licensee's awareness of the reactor water cleanup isolation issue to be indicative of an effective and responsive industry events followup process.

E2.6 System Walkdowns

a. Inspection Scope

The team conducted a walkdown of the standby service water system, the 125 Vdc system and the automatic depressurization system to determine equipment operability and equipment material condition. The team also conducted walkdowns of other plant areas, including the radiation protection area, to determine general plant housekeeping.

b. Observations and Findings

During the plant walkdowns, the observed the selected systems to determine equipment operability and material condition. The team also observed valve positions in the selected systems to verify that they were in the proper positions. The team did not identify any system problems as the result of these walkdowns.

The team's walkdowns of other selected plant areas found that excellent housekeeping was being maintained. The excellent conditions were evidenced by an absence of leaks, debris, material storage problems, and a lack of corrosion (rust) on equipment.

c. Conclusions

Overall, the team concluded that both equipment material condition and plant housekeeping was excellent.

E4 Engineering Staff Knowledge and Performance (37550)

a. Inspection Scope

The team interviewed six plant engineering supervisors and five plant engineers. Interview topics included management expectations for plant engineers, training regarding system interrelations, and the interface between plant engineering and other plant organizations. The team also questioned plant engineers on knowledge of their assigned systems, and conducted system walkdowns with the plant engineers.

b. Observations and Findings

The team found management expectations for plant engineers were appropriate, clearly defined, and not excessive. Plant engineers were effectively coordinating with design engineering to evaluate and improve their specific systems. The team noted that design engineer recommendations were being addressed by the plant engineers. Plant engineering indicated that communication and cooperation with operations, maintenance, and design engineers were effective in resolving work issues, and also in assuring that modifications were properly installed. Team interviews and plant walkdowns indicated that plant engineers were qualified in and knowledgeable of their assigned systems.

c. Conclusions

The team concluded that engineering management expectations were clear and understood by plant engineering personnel. Communications between plant engineering and other plant departments was effective. Plant engineers were knowledgeable of their assigned systems.

E5 Engineering Staff Training And Qualification (37550)

a. Inspection Scope

The team reviewed the licensee's training and certification program requirements for the engineering staff. This review included a review of training records for the engineering staff.

b. Observations and Findings

The team noted that the engineering support training program consisted of orientation training, position-specific training, continuing training, and procedural training. Position-specific training provided for plant engineering included boiling water reactor technology, plant operations, detailed descriptions for plant systems and components, and root cause analysis. The team noted that the plant engineering qualification program was improved about 18 months ago by requiring each plant engineer to complete a system certification card for their system. After the certification card qualification was performed, the plant engineer was required to pass an oral examination given by a qualification board. The purpose of oral examination was to provide the plant engineer with an opportunity to demonstrate readiness for certification as an expert on their assigned system. The team noted that this qualification process was a requirement for plant engineers prior to assuming a new system assignment. The team noted that plant engineers were certified under the improved program on 44 percent of the primary systems and that all primary system certifications were scheduled for completion by February, 1997.

The team found that the design engineer training program required similar training which qualified the design engineer to perform a particular function, for example, engineering of piping, civil, or mechanical systems or components. The team's review of training records indicated that design engineers were maintaining their expertise by receiving training on subjects such as bolting, the structural analysis computer program, fracture mechanics, and water-hammer. The team found that approximately 95 percent of the design engineers completed this qualification.

c. Conclusions

The team concluded the training program for the engineering staff was effectively supporting the role of the plant and design engineers. Particularly noteworthy was the requirement that plant engineers be certified for a specific system prior to being assigned to that system.

E7 Quality Assurance In Engineering Activities (37550)

a. Inspection Scope

The team reviewed a self-assessment of plant engineering that was performed on September 18-22, 1995, to evaluate the effectiveness of the licensee's controls in identification and resolution of plant problems.

b. Observations and Findings

The self-assessment noted that plant engineers were knowledgeable, highly motivated, dedicated, receptive to change and had accepted ownership of their systems. The assessment found that communication and relationship with the operation and maintenance organizations was very good. The report concluded, however, that only a small percentage of the plant engineers had completed their certification cards. The report also noted that a supporting role for plant engineers may be more appropriate on the less critical component type problems, and that several plant engineers and their supervisors worked excessive amounts of overtime. Generally, these findings were consistent with those identified by the team. Specifically, the team noted that plant engineers were knowledgeable, had been effective in identifying problems, and made progress in completing their certifications.

c. Conclusions

The team concluded that the self-assessment was consistent with the team's findings and was effective in identifying strengths and weakness in the plant engineering department.

V Management Meetings

The team presented the inspection results to members of licensee management at the conclusion of the inspection on September 13, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Amburgey, Senior Engineer
T. Carpenter, System Engineer
F. Conley, Site Engineer
R. Davey, Manager, Electrical & Instrumentation and Control
E. DeWeese, Site Engineer
J. Dimmette, General Manager
D. Dormady, Manager, Plant Engineering
B. Fountain, Technical Specialist IV
A. Fredieu, Supervisor, System Engineering
G. Hendl, System Engineer
R. King, Director, Nuclear Safety & Engineering Affairs
M. Krupa, Manager, Operations
T. Leonard, Director, Engineering
D. Lorfing, Supervisor, Licensing
R. McAdams, Senior Licensing Engineer
J. McGaha, Site Vice President

NRC

D. Proulx, Resident Inspector
W. Smith, Senior Resident Inspector
C. VanDenburgh, Chief, Engineering Branch

LIST OF INSPECTION PROCEDURES USED

IP 37550	Engineering

LIST OF ITEMS OPENED AND CLOSED

Opened

50-458/9627-01	VIO	Failure to translate plant design bases into plant procedures and calculations
50-458/9627-02	IFI	NRR to review whether near-buoyant objects should be considered in the standby service water system licensing basis.

ATTACHMENT

LIST OF DOCUMENTS REVIEWED

Plant Procedures

Procedure No.	Revision	Title
ADM-0031	5	"Temporary Alterations"
AOP-0004	11B	"Loss of Offsite Power"
AOP-0050	8	"Station Blackout"
ARP-870-55	6B	"P870-55 Alarm Response," Alarm No. 0658, "STBY SERVICE WTR COOLING TOWER HIGH TEMP."
EDG-AN-0001	0	"Guidelines for S&EA Review of Modification Request"
EDG-PR-0001	0	"Reliability Monitoring Program,"
EDP-AA-10	9	"Training Requirements for Engineering Department Personnel"
EDP-AA-80	2	"Modification Forms"
EDP-AN-01	5	"Control of System Notebooks for Probabilistic Safety Assessment"
EDP-PE-09	2	"Part Interchangeabilty Evaluation"
EDS-AA-001	2	"Engineering Standards"
ENG-3-006	15	"Modifications Design Control Plan Definitions, Residual Processes and Guidance"
ENG-3-026	2	"Document Change Notices (DCNS)"
ENG-3-028	2	"Processing of System Design Requirements Documents (SDRDs)"
ENG-3-033	3	"Modification Design Control Plan"
ENG-3-037	0	"Engineering Request Process"
ISE-13-001	9	"ISEG Organization, Responsibilities and Training"

Procedure No.	Revision	Title
ISE-13-003	6	"ISEG Plant Assessment and Special Analyses"
ISE-13-004	7	"ISEG Operating Experience Review"
ISE-13-005	6	"ISEG Recommendation Status"
ISE-13-006	4	"ISEG Record of USQD Review"
ISE-13-007	4	"ISEG Scram Analysis Techniques"
RBNP-030	9	"Initiation and Processing of Condition Reports"
R-SAD-TQ-005	4	"Station Training Program"
SOP-0011	12	"Main Steam System (SYS #109)"
SOP-0018	17	"Normal Service Water (SYS #118)"
SOP-0049	9A	"125 VDC System"
STP-000-0201	14B	"Monthly Operating Log Verified TS 3.5.1.3 for Minimum Accumulator Air Pressure of 131 PSIG"
STP-000-6606	1&2	"Section XI Safety and Relief Valve Testing"
STP-051-4228	6	"ADS A Timer Channel Functional Test"
STP-051-4229	6	"ADS B Timer Channel Functional Test"
STP-051-4294	2A	"ADS A Drywell Pressure Bypass Timer, Channel Functional Test"
STP-051-4297	1	"ADS B Drywell Pressure Bypass Timer, Quarterly Channel Functional Test"
STP-051-4298	5A	"ADS A Drywell Pressure Bypass Timer, Channel Functional Test"
STP-051-4299	6A	"ADS B Drywell Pressure Bypass Timer, Channel Functional Test"
STP-202-0602	10	"Safety Relief Valve Division I Operability Test for TS 3.5.1.6, 3.5.1.7"

Procedure No.	Revision	Title
TP-92-008	0	"Flow Balance and Design Flow Verification for The Standby Service Water System and the Normal Service Water System"
TSP-0033	8	"System Engineering Duties and Responsibilities"
TTP-7-025	7	"Engineering Support Personnel Training Program"

Plant Modifications

No.	Title
MR 93-0009	"Install Backup Power Source to Support Safety-Related Control Power During Station Blackout"
MM 94-0152	"Revise Timer Setpoints for SBCT Fan Starting"
MM 94-0182	"Install Battery Eliminator Circuitry in the E22 Battery Charger 1E22*S001CGR"
MR 95-0003	"Replace the Main Steam SRV Disc Inserts with a New Flexi-Disc Design Insert"
MR 95-0009	"Suppression Pool Cleanup, Cooling and ADHR System - Outage Scope"
MR 95-0040	"Install Cross Ties to Prevent Water Stagnation"
MR 95-0057	"Provide Method to Reject Water from the SCT"

Temporary Modifications

No.	Title
PMR 89-0025	"Reroute Power to 1SCM*PNL01B"
PMR 89-0026	"Replace Failed Transformer 1RPS*XRC10B1"
TA 96-0020	"Installation of DRS Motor HVC-ACU2B"

Condition Reports

CR No.	Title
95-0167	"Inadequate SSW Flow at Minimum Basin Levels Assuming Pump Degradation"
95-0662	"During Performance of STP-203-6305, HPCS Pump Output Breaker Closed and Immediately Tripped Open"
95-0850	"Surface Corrosion Found on Vertical Support of Division I Battery"
96-0048	"ADS Accumulator Check Valves LLRT Failures"
96-0073	"Variation in Test Current During Testing of Division I Batteries"
96-0082	"Check Valve Hanger Out-Of-Tolerance Conditions"
96-0242	"Disc Hanger Found Bent in Check Valve"
96-0244	"Check Valve Spring Not Seating Properly"
96-0251	"Test Equipment Problems During Surveillance Testing of Division II Battery Bank"
96-0271	"Incorrect Spring Found in Check Valve"
96-0421	"ADS Accumulator Check Valve LLRT Failures"
96-0484	"Check Valve Spring Not Aligned Properly"
96-0523	"Preventive Maintenance Steps N/A'd Without Engineering Concurrence"
96-0558	"Main Steam Safety Relief valves Set Point Tests"
96-0567	"During Review and Closure of CR 95-0662, it became Apparent to the System Engineer that a Related Document, SAL 352.1, was not in the Vendor Information System"
96-0673	"SBO Diesel Voltage and Frequency Began to Fluctuate During Testing"
96-1048	"Possible Part Problem with Circuit Breakers Repaired by Vendor"
96-1270	"Failure to Accelerate Testing Frequency for Division I Safety-Related Batteries"

CR No.	Title
96-1273	"Control Building Chiller Vendor Manual Discrepancies"
96-1636	"Abnormal Operating Procedure AOP-0004, 'Loss of Offsite Power,' Not Consistent With USAR"
96-1637	"SAR Updated Before Completion of 10 CFR 50.59 Review"
96-1644	"Throttle Valve Positions in System Operating Procedure SOP-0018" Not Per Flow Balance Test Results

Engineering Requests

ER No.	Title
96-0070	"Improve the Reliability of the E22 125 Volt Battery"
96-0541	"Leaving Load Bank Next to SBO Diesel Generator in the Yard"
96-0547	"Request for the Seismic Review of the latest Revisions to Safety-Related Battery Maintenance/Surveillance Procedures to Allow for the Necessary Tie-Wrap Tag Attachments"
96-0564	"Performance Discharge Tests Are Inconsistent on Battery ENB-BAT01A"
96-0565	"Test Requirements for DIV-III Battery"

Calculations

Calculation No.	Revision	Title
G13.3 E-143	7	"Standby Battery ENB-BAT01A Duty Cycle, Current Profile, and Size Verification"
G13.18 E-143	8	"Standby Battery ENB-BAT01A Duty Cycle, Current Profile, and Size verification"
G13.18 E-200	1	"Overcurrent Devices Set Points", Addendum N
G13.18.2.3*207	0	"GL 89-10 Design Basis Review for 1E51*MOVF068"
G13.18.2.4*047	0	"Standby Service Water Division 1 and 2 Small Bore Cross Tie Sizing - Flow Rate and Orifice Sizing"

Calculation Number	Revision	Title
G13.18.13.2*073	0	"Estimated PCT with One ADS Valve Out-of-Service"
G13.18.2.6*020	0	"Minimum Air Pressure Required for ADS Accumulators"
G13.18.2.6*022	0	"Minimum Accumulator Pressure Required for ADS and Non-ADS Accumulators"
G13.18.2.6*023	0	"Technical Specification TSI-91-01 ADS Header Minimum Pressure for Operability"
G13.18.2.6*033	0	"River Bend ADS Evaluation Using a Non-ADS Accumulator"
G13.18.2.6*041	2	"Flow Required Through the Service Water Side of an RHR Heat Exchanger During LOP or LOP-LOCA Conditions Considering "Max Safeguards"
G13.18.10.6*065	0	"Qualification of Small Bore lines Crosstie to Standby SWP Piping to Prevent Water Stagnation"
G13.18.13.2*086	0	"Effects of Maximum Safeguards Operation on the Ultimate Heat Sink (Standby Cooling Tower)"
LCR 1.ILCCP.011	2	"Component Cooling Plant Supply Pressure to SFC & RHS, CCP-PT1A"
LCR 1.ILCCP.012	3	"Component Cooling Plant Supply Pressure to SFC & RHS, CCP-PT1B"
LCR 1.ILSWP.039	3	"Control Building Chilled Water Recirc Pump A Discharge Line Flow, SWP-FT69A"
LCR 1.ILSWP.040	3	"Control Building Chilled Water Recirc Pump B Discharge Line Flow, SWP-FT69B"
SPDS-12210-IA	5	"CCP Supply to SFC & RHS Low Pressure Isolation, CCP*ES1 1CCP*ES1A,C,E,G & 1CCP*ES1B,D,F,H"
SPDS-12210-IA	6	"Service Water Flow to Control Building Condenser SWP*ESX69A (1HVK*CHL1A) Normal Flow Interlock Start Permissive"
12210 E-153	4	"Verification of Static Battery Charger Size - Standby Battery Chargers"

Calculation No.	Revision	Title
12210 E-181	1	"DC Cable Size Verification"
12210 E-200	1	"Overcurrent Devices Set Points"
12210 E-209	1	"Cable Loop Length Criteria for Voltage Drop - DC Circuits"
12210-PM-236	0	"Standby Service Water Operation with One Pump Available"

Part Interchangeability Evaluations

PIE No.	Title
00428	"Amplifier Board for Option N0037"
00559	"Replace Spiral Wound gasket with Non Asbestos filler Material"
00581	"Replace Piston Disc Assembly"
00642	"Replace radial Single row Bearings"
00647	"Agastat Series ETR Relays"
00648	"Agastat Series EGP Relays"
00725	"Replace Target Rock Valve"
00744	"Replace Bearings in Limitorque Operators with Normal Internal radial Clearances"
00789	"Generic Change of Thread Sealant for all Locations"
00793	"Disc Hanger of Vacuum Breaker Check Valve"
00854	"Replace Limitorque Drive Sleeve, 2 Piece Drop Nut"
00856	"Replace Snubber Cotter Pin with Shorter Pin"
00873	"Replace Inverter Capacitor with one from Different Manufacturer"
00874	"Replace Inverter Capacitor in Inverter with one with Higher Voltage rating"

PIE No.	Title
00876	"Replace Inverter Capacitor with one from Different Manufacturer"
00878	"Replace Inverter Capacitor with one with Higher Capacitance"
00879	"Generic Replacement of Deep Grooved Ball Bearings"
00893	"Replace Various ASTM A296 Parts and Material with ASTM A743"
00915	"Replace Various ASTM A276 Parts and Material with ASTM A479"
00919	"Replace Sealant, Pipe Thread; Connecting Electrical Housing to Sensor"
00924	"Replace O-Ring for various Limitorque Actuators"
00975	"Replace Inverter Capacitor with one with Higher Capacitance"

Design Change Notices

DCN No.	Title
90-0186	"Revise Documents to Agree with MOV Nameplate data"
90-0197	"Revise Elementary Diagram to Agree with As-Built"
92-0403	"Revise Various Plant One-Line Drawings for Referencing and Editorial Errors"
93-0248	"Revise Elementary Diagrams to Agree with As-Built"
95-0147	"Correct Continuation label on Drawing"
96-0224	"Revise Drawings Affected by MR-95-0056"

Maintenance Action Items

MAI No.	Title
302737	"Perform Mechanical Retest for ADHR/Suppression Pool Cleanup"

303008	" Clean Battery Bank 1A Connections and Re-Baseline During RF6"
303009	" Clean Battery Bank 1B Connections and Re-Baseline During RF6"
303975	"One Cell of Battery Bank S001 Replaced"
303993	"MSRV Air Operator Accumulator Check Valve B21-VF039C Failed LLRT"
303994	"MSRV Air Operator Accumulator Check Valve B21-VF039H B Failed LLRT"
303995	"MSRV Air Operator Accumulator Check Valve B21-VF039S Failed LLRT"
303996	"MSRV Air Operator Accumulator Check Valve B21-VF039K Failed LLRT"
303997	"MSRV Air Operator Accumulator Check Valve B21-VF039D Failed LLRT"
303998	"MSRV Air Operator Accumulator Check Valve B21-VF039E Failed LLRT"
303999	"MSRV Air Operator Accumulator Check Valve B21-VF039B Failed LLRT"
304105	"Replace One Cell of Battery Bank S001"

Drawings

No.	Revision	Title
EE-1AA	9	"480 V One Line Diagram Standby Bus 1EJS*LD1A & 2A"
EE-1AB	9	"480 V One Line Diagram Standby Bus 1EJS*LDC 1B & 2B"
EE-1ZC	8	"One line Diagram, Standby Bus A&B, Low Voltage Distribution System, Drawing No. EE-1ZC"
EE-1ZE	14	"125 VDC One Line Diagram, Normal Bus A, 1BYS-SWG01A, 1BYS-PNL02A1, 02A2, 03A"

EE-1ZG	12	"125 VDC One Line Diagram, Standby Bus A, 1ENB-SWGR01A,1ENB-PNL02A,03A"
PID-3-1B	16	"System 109 - Main Steam"
PID-3-1A	15	"System 109 - Main Steam"
PID-9-10A	26	"Engineering P&I Diagram, System 118, Service Water - Normal"
PID-9-10B	35	"Engineering P&I Diagram, System 118, Service Water - Normal"
PID-9-10C	23	"Engineering P&I Diagram, System 118, Service Water - Normal"
PID-9-10D	27	"Engineering P&I Diagram, System 118, Service Water - Normal"
PID-9-10E	17	"Engineering P&I Diagram, System 256, Service Water - Standby"
PID-9-10F	25	"Engineering P&I Diagram, System 118, Service Water - Normal"
PID-9-10G	0	"Engineering P&I Diagram, SWP Corrosion Coupon And Monitoring Rack System 118, "C" Tunnel El. 67' 6"
PID-9-10D	27-Redlined	"Engineering P&I Diagram, System 118, Service Water - Normal"
PID-9-10E	17-Redlined	"Engineering P&I Diagram, System 256, Service Water - Standby"
12210-ESK-11ENB02	7	"Elementary Diagram - 125 VDC Standby Switchgear Battery Systems"

Miscellaneous Documents

Technical Specifications

Final Safety Analysis Report

System Design Requirements Documents SDRD-P30, Revision 0, "Main Steam Safety/Relief Valve System"

System Design Requirements Documents SDRD-E8, Revision 0, "125 VDC System"

Licensed Operator Training Manual Lesson plan No. LOTM-57-7-DC, "Distribution," June 13, 1996

System Health Report, "Safety Relief Valves/Automatic Depressurization Control - System No. 202"

System Health Report, "125V dc Distribution System - System No. 305," February and June 1996

Procedure Action Request AOP-0050R08EC-A, "Station Blackout"

Preventive Maintenance Task Instruction EL16212-03, "BYS-EG1"

Preventive Maintenance Task Instruction ME03945-00, "1BYS-EG1"

Preventive Maintenance Task Instruction ME03946-00, "1BYS-EG1"

Preventive Maintenance task Instruction ME03947-00, "BYS-EG1"

Entergy Operations, Inc. Report Number EA-RA-92-0001-M, "Conformance of River Bend Station with the Station Blackout Rule (10CFR50.63) and NUMARC 87-00"

River Bend Station Letter RBG-38077, "RBS IPE Submittal," dated January 15, 1993

SAL 352.1, "Latest Design Configuration: GE Type AM Circuit Breakers and Medium Voltage Switchgear"

Operating Experience Statement of Action 224.309, "Latest Design Configuration GE Type AM Circuit Breakers and Medium Voltage Switchgear"

OE 7846I, "GE 4kV Magna-Blast Breakers Fail to Latch"

OE 7875I, "Zinc Plating of Circuit Breaker Parts Can Cause Inadvertent Hydrogen Embrittlement of Other Parts"

Standing Order 120, Revision 1, dated May 8, 1995

Engineering Report TSD 95-0246

July 10, 1996 Memo, From Christopher McDonald, Application Engineer, Hayward Tyler Inc. to Entergy Operations, Inc.

94-12-I-SSFI Audit Report, RBS Safety System Functional Assessment

Specification for System Design Requirements documents (SDRDs) Upgrade Project, Revision 1, dated March 11, 1996

Technical Requirements Manual, Section 5.2.3, "Independent Safety Engineering Group (ISEG)," Revision 5, and Section 5.8, "Review and Audit," Revision 5

NRC Office of Nuclear Reactor Regulation Safety Evaluation Report related to Amendment 81 to River Bend Station Facility Operating License NPF-47, dated July 20, 1995

EPRI TR-106306, Losses of Off-Site Power at U.S. Nuclear Power Plants - Through 1995, dated April 1996