ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/95-25

License: NPF-47

Licensee: Entergy Operations, Inc.
P.O. Box 220
St. Francisville, Louisiana

Facility Name: River Bend Station

Inspection At: St. Francisville, Louisiana

Inspection Conducted: October 22 through December 2, 1995

Inspectors: D. L. Proulx, Resident Inspector
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Approved: Gregory A Pick for 1/8/96
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Inspection Summary

Areas Inspected: Routine, unannounced inspection of licensee actions in response to events, plant operations, maintenance and surveillance observations, onsite engineering, plant support activities, followup, and review of a licensee event report (LER).

Results:

Plant Operations

- The licensee's response to a reactor core isolation cooling (RCIC) system isolation, as a result of the failure of a temperature switch, was appropriate (Section 2).

- Operations performance during this inspection period was good in that systems were lined up properly, appropriate operating logs were kept, and management provided a consistent presence for oversite and communication purposes (Section 3).

- Operators did not formally verify the status of the valves in the residual heat removal (RHR) system prior to performing the pump operability surveillance. This indicated that inconsistencies could exist in the licensee's use of the term "verify." Licensee management identified that the procedure reference was intended to have operators assure that they had confidence in the system lineup by reviewing administrative configuration controls and control panel indications rather than completing a system lineup for each surveillance performance (Section 5.2).

Maintenance

- The maintenance activities associated with the replacement of bolts on the Division II emergency diesel generator (EDG) exhaust header was performed satisfactorily (Section 4.1).

- The planned outage of the Division I EDG took 12 hours longer than planned because of weak preplanning and a poorly implemented modification. This appeared to be an isolated incident and management was aggressively involved in ensuring that future system outages did not unnecessarily increase equipment out-of-service time (Section 4.2).

- The licensee performed minor maintenance on the Division I and II EDGs while the Division III EDG was inoperable. This indicated a weakness in the licensee's provisions for minimizing maintenance risks during power operations. Management stated that this issue would be addressed (Section 4.3).

- A contractor employee installed a torque switch backwards on a safety-related motor-operated valve (MOV). Although this concern had minor safety significance because the limit switches, in lieu of the torque switch, controlled the valve operation. This issue emphasized the need for proper supervision of contractors during outage work. This issue resulted in a noncited violation for the failure to install a torque switch in accordance with instructions (Section 4.4).

- The licensee failed to perform Surveillance Requirement (SR) 3.3.1.1.3, adjustment of the average power range monitors every 7 days, as required by the Technical Specifications (TS). This error was caused by improper implementation of the surveillance frequency changes specified in Amendment 74 to the TS. In September 1994, the licensee reported a previous occurrence of improper implementation of surveillance requirements, which were also specified in Amendment 74, in LER 94-29. Since recurrence of the same problem was identified, it was apparent that the corrective actions for LER 94-29 were inadequate. The failure to perform a surveillance test at the specified frequency is a violation (Section 5.3).

Engineering

- The configuration of a low pressure core spray (LPCS) system instrument line did not contain acceptable containment isolation provisions in that an isolation valve outside containment was not locked to provide positive control of the isolation valve. This is a violation of General Design Criterion (GDC) 55 (Section 3).
- The surveillance procedure for the standby liquid control (SLC) system contained an incorrect drawing that identified the vibration monitoring locations for the SLC motor instead of the pump. The safety impact of the error was minor since the procedure was recently revised and the error was identified during the first performance of the test since the procedure was revised. The attachment of an incorrect drawing to a procedure was determined to be a noncited violation (Section 5.1).
- The licensee implemented an excellent vibration monitoring program for safety-related pumps (Section 6.1).
- Engineering personnel initiated efforts to test new temperature switches to replace the switches currently installed that have a history of causing inadvertent system actuations (Section 6.2).
- Reactor engineers identified that the load line limit analysis indicated that the licensee was not approved for operation above the 100 percent rod line for Cycle 7 and also had not been for Cycles 3-6. The vendor subsequently verified that specific approval for each cycle was not required, as a generic analyses had been completed and demonstrated no adverse affects on plant safety. This issue indicated a weaknesses in the licensee's process for performing independent, thorough reviews of vendor supplied information in that the apparent missing analysis was not identified for five operating cycles (Section 6.3).

Plant Support

- The inspectors found an installed scaffold, prestaged in anticipation of the upcoming refueling outage, that blocked a 10 CFR Part 50, Appendix R emergency light beam. This indicated the need for improvement in assessing the impact of staging equipment in the plant (Section 7.1).
- Personnel did not always observe posted radiation protection guidelines in that a number of individuals did not frisk their hands prior to picking up the frisking probe (Section 7.2).
- Housekeeping in the plant was observed to be good (Sections 7.3).

Summary of Inspection Findings:

New Items

- Violation 458/9525-01: Positive control of containment isolation valves was not maintained (Section 3).

- Noncited Violation: Failure to follow a procedure for the installation of a torque switch in an MOV (Section 4.4).

- Noncited Violation: Failure to maintain a procedure for the performance of surveillance testing (Section 5.1).

- Inspection Followup Item 458/9525-02: Review licensee's actions for establishing requirements for verification of system status before performing surveillance testing (Section 5.2).

- Violation 458/9525-03: Surveillance testing of the APRMs was not performed at the specified frequency (Section 5.3).

Closed Items

- Inspector Followup Item 458/9331-01 was closed (Section 8.1).
- Violation 458/9415-04 was closed (Section 8.2).
- LER 458/95-08 was closed (Section 9).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the reactor was operating at 99 percent power. Reactor power was steadily reduced throughout this inspection period because of fuel depletion (coastdown) at the end of the operating cycle. The reactor was at 90 percent power at the end of this inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

On October 24, 1995, an inadvertent isolation of the RCIC system occurred when a newly installed Riley temperature switch spuriously actuated. Because of historical spurious trips of earlier model temperature switches, licensee personnel changed the Division II RCIC isolation temperature switch to a newer model. Also, because the new temperature switches had a history of problems, the licensee bench tested the energized temperature switch for 10 days prior to installing it in the isolation logic panel. Although the new temperature switch passed the calibration procedure, it failed approximately 1 hour after installation. After licensee personnel verified that the old temperature switch worked properly, the switch was calibrated and reinstalled. After replacement of the temperature switch, no additional problems have occurred. Additional discussion of this issue is provided in Section 6.2 of this inspection report.

Operations personnel responded appropriately to the inadvertent actuation. The licensee submitted LER 95-008, which described this event and the corrective actions.

3 PLANT OPERATIONS (71707)

The inspectors routinely toured the control room and observed operator performance. On several occasions, the inspectors noted operations management in the control room observing and briefing control room operators on management's expectations. Additionally, control room staffing was appropriate and in conformance with the applicable requirements; operators were attentive to duties; and housekeeping in the control room was excellent.

The inspectors reviewed operating logs and records against the TS and administrative control procedure requirements and determined the documentation to be satisfactory. The inspectors observed process instruments for correlation among channels and conformance with TS requirements.

On November 1, 1995, the inspectors walked down three clearance orders to verify that tags were in place and that equipment was in the condition specified. No discrepancies were identified during the observations or independent verification of the activities described above.

The inspectors walked down selected safety-related systems to verify that the systems were aligned in accordance with plant procedures. The systems were: (1) LPCS, (2) RCIC, and (3) EDG I. The inspectors found that the systems, for the portions walked down, were in good material condition and were aligned in accordance with applicable licensee procedures.

During the walkdown of the LPCS system, the inspectors traced the instrument line, which tapped off of the LPCS injection line between the containment structure and the outboard containment isolation valve, from its origination to the instrument rack. The instrument line configuration consisted of two open valves, an instrument, and two manual isolation valves. The inspectors noted that neither of the manual valves were locked or otherwise controlled; however, both valves were shut, which was the appropriate position.

Although the valves were found to be in the proper position, the inspectors noted that the control of the instrument valves did not meet the provisions for containment isolation stated in 10 CFR Part 50, Appendix A, GDC 55. GDC 55 states, in part, that each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with one automatic isolation valve inside and one locked closed isolation valve outside of containment unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other design basis.

The licensee's failure to positively control containment isolation for the LPCS pressure instrument line by having a locked manual valve outside containment is a violation of GDC 55 (458/9525-01).

When the inspectors notified the licensee that the LPCS system configuration did not meet GDC 55 or Section 6.2.3.4 of the Updated Safety Analysis Report, the licensee stated that these references did not apply to this particular instrument line because the line did not directly penetrate containment but tapped into another line that penetrated containment. In addition, the licensee stated that all of the applicable containment isolation provisions were listed in the Updated Safety Analysis Report, were not questioned by the NRC during the plant licensing process, and were thus previously accepted.

The inspectors considered the licensee's definition of a line requiring containment isolation provisions to be narrowly focused and nonconservative. In addition, the inspectors noted that the LPCS instrument line configuration, as shown on the process and instrumentation diagram, did not completely match the as-built condition. This may account for the reason as to why the licensee may have missed this line and should have considered containment isolation provisions for the LPCS pressure instrument line.

Although the licensee did not specifically acknowledge that a discrepancy existed, the licensee stated that the LPCS instrument line configuration was not consistent with other commitments on containment penetrations. The licensee initiated Condition Report 95-1145 to document this concern and to implement corrective actions. The licensee indicated that they would lock shut the drain valves for the affected instrument rack. The licensee performed a further review of other systems and noted that an RHR C instrument line had a similar design vulnerability. Subsequently, the licensee locked the drain valves for the affected RHR C instrument rack. This is another example of the licensee's failure to maintain the configuration of a containment isolation valve. This issue also will be addressed during followup on the violation discussed above.

4 MAINTENANCE OBSERVATIONS (62703, 92902)

During this inspection period, the inspectors observed portions of the maintenance activities listed below. The observations included a review of the maintenance work orders and other related documents for adequacy, worker adherence to procedures, proper tagouts, TS compliance, quality controls, radiological controls, observation of work and/or retesting, and appropriateness of retest requirements.

4.1 Maintenance Work Order R222288 - Replacement of Bolts on Division II EDG

Condition Report 94-1616, dated December 12, 1994, identified that two bolts on the Division II EDG exhaust manifold were found to be broken. The root cause determination performed by licensee personnel concluded that the bolts failed due to fatigue as a result of cyclic loading. As a result, licensee personnel decided to replace the installed stainless steel bolts with higher strength carbon steel bolts.

The inspectors verified that personnel properly implemented the tagouts (RB-952035/RB-952029) for this work. The work instructions specified that the bolts be torqued to 60 foot-pounds; however, because of the difficult locations of some of the bolts, an adaptor had to be utilized by the craft to reach the bolts with the torque wrench. The inspectors reviewed Procedure GMP-0018, "General Torquing Guide," and confirmed that the mechanics properly performed the torquing.

Based on the observations made by the inspectors, it appeared that the licensee performed this maintenance activity in a satisfactory manner.

4.2 EDG Maintenance Delays

During the week of October 25, 1995, the licensee removed the Division I EDG from service to perform various maintenance tasks. The licensee planned to have the Division I EDG inoperable for 30 hours, including tagouts, planned work, and retests. The licensee performed a probabalistic risk assessment and determined that this work did not provide a significant contribution to the overall risk of plant safety. However, because of problems encountered during the performance of the work activities, the Division I EDG remained inoperable for approximately 42 hours.

One of the items to be performed involved a modification request that installed tubing and a level gage for the jacket water tank. Previously, the

Division I EDG had a standpipe of tygon tubing to indicate water level. The licensee drained the tank and installed the new tubing and level gage. However, the tygon tubing standpipe had also been used to add ethylene glycol, a corrosion inhibitor, to the jacket water expansion tank. With the new level gage installed, the licensee did not have the capability to add ethylene glycol to the tank because engineering had not anticipated the need for this capability when developing the modification request, nor was it discovered by the Facility Review Committee during the approval process.

The licensee revised the work package in an attempt to establish various methods for pumping the ethylene glycol into the expansion tank. The licensee finally added the ethylene glycol by removing and reinstalling a manway at the top of the tank. Other issues that contributed to the additional outage hours included: (1) minor emergent work, (2) operations concerns that work packages were not included in the clearance boundary, and (3) unavailability of parts.

Because of concerns with the preplanning of the Division I EDG outage, the licensee initiated Condition Report 95-1084 to document this occurrence and to address the root causes. Licensee management was appropriately involved with the condition report resolution. The plant manager discussed this item with his staff to emphasize the importance of proper preplanning to minimize plant risk. The inspectors concluded that management's participation was appropriate.

The inspectors concluded that Division I EDG work that rendered the EDG inoperable for 42 hours, instead of the planned 30 hours, demonstrated weak preplanning. The inspectors noted that these additional hours of Division I EDG inoperability increased the overall risk to plant safety by a very small amount. However, the inspectors noted that if delays in outage time for safety-related systems occurred frequently, the change in overall risk could be significant.

4.3 Concurrent Work on Different EDG Trains

On November 14, 1995, during a tour of the EDG building, the inspectors noted an instance in which the licensee did not appear to fully consider risk minimization during on-line maintenance. The Division III EDG was tagged out for preplanned maintenance, which placed the plant in a 72-hour shutdown TS action statement. The inspectors entered the Division III EDG room and noted that the licensee was completing final preparations to start the work. The inspectors subsequently entered the Division I and II EDG rooms to determine if these systems were in a state of readiness with one of the three EDGs already inoperable.

Upon entry into the Division I and II EDG rooms, the inspectors noted that work was in process. In the Division II EDG room, the EDG control panel was opened with an electrician and an equipment operator cleaning and inspecting the internals of the panel. In the Division I EDG room, instrument and control technicians were calibrating Temperature Indicating

Switch 1HVP-TIS-112A, which controls the speed of the ventilation fans for the room.

The inspectors expressed concern to the operations shift supervisor that personnel had not assessed the risk of having one EDG inoperable and performing work on equipment associated with the other two EDGs simultaneously. The operations shift supervisor stated that the minor nature of the work performed on Division I and II EDGs was allowed because it did not render the EDGs inoperable and did not increase the overall risk.

The inspectors agreed that the work performed on the Division I and II EDGs did not cause these EDGs to be inoperable. However, the inspectors noted that dropped tools, bumped equipment, shorted leads, or any other unforeseen problems could render the Division I and II EDGs inoperable. In addition, the inspectors noted that the licensee took no additional precautions to ensure that the operability of Division I and II EDGs were not compromised. Therefore, the inspectors concluded that minor work on equipment and systems, redundant to inoperable equipment and systems, may pose an unanticipated increase in overall risk.

The inspectors discussed this issue with the plant manager. The plant manager noted that during refueling outages, when a safety train was removed from service, the operable trains of redundant equipment were treated as protected systems. No work may be done on a protected system, and in fact, signs are placed on the entrance to the equipment rooms preventing entry without control room permission. The plant manager stated that sufficient sensitivity existed for risk during outage but that provisions for protecting redundant equipment and systems during plant operations was not equivalent. The plant manager also stated that their staff would evaluate the need for additional consideration of risk during power operation.

4.4 Improper MOV Maintenance

On October 25, 1995, during preventive maintenance activities, the licensee identified that the torque switch for Valve 1SWP*MOV96B, normal service water to standby service water isolation, had been installed upside down. Craft personnel corrected the deficiency and the licensee initiated Condition Report 95-1018 to document this concern and to provide corrective actions.

The inspectors interviewed the system engineer and the maintenance superintendent. These licensee personnel stated that the motor actuator for Valve 1SWP*MOV96B deenergized by operation of the limit switches and not the torque switch, therefore, this concern had minor safety significance with respect to system operability, since the safety function for this valve was unaffected.

However, the inspectors expressed a concern that this issue demonstrated a lack of training and control of contract personnel involved with the maintenance of MOVs. The licensee responded that contract personnel refurbished the MOV during Refueling Outage 5 (Spring 1994) and that the licensee had accepted proficiency of the workers based upon the contractor's certification. The licensee stated that actions would be taken to ensure that the qualifications of contract MOV personnel were satisfactory by requiring contract personnel to demonstrate proficiency in the maintenance of MOVs, at the licensee's MOV training facility, prior to the upcoming refueling outage. When this MOV was refurbished, contract personnel apparently failed to follow the instructions provided by the maintenance work order, which is a violation of TS 5.4.1.a. However, this violation is not being cited because it meets the criteria of Section VII.B.1 of the Enforcement Policy. Specifically, the bases for not citing the violation are: (1) the problem was identified by the licensee, (2) corrective actions for a previous violation would not have prevented this violation, (3) timely corrective actions have been implemented to address this issue, and (4) the violation was not willful.

5 SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the performance of portions of the surveillance tests listed below. The observations included a review of the procedures for technical adequacy, conformance to the TS, verification of test instrument calibration, observation of all or part of the actual surveillance, removal and return to service of the system or component, and review of the data for acceptability based upon the acceptance criteria.

5.1 Procedure STP-201-6312 - "Division II SLC Quarterly Pump and Valve Operability Test"

On October 24, 1995, the inspectors observed licensee personnel perform the Division II SLC pump operability test. The inspectors verified that the test procedure properly implemented the requirements of the TS and reviewed the test flowpath on the system process and instrumentation diagram to verify the system was correctly lined up. Engineering personnel collected the pump vibration, motor vibration, and recirculation flow data. The flow data was obtained by using a strap-on ultrasonic flow instrument. The test method established a reference pump discharge pressure and measured the corresponding flow rate through the recirculation line back to the test tank.

The inspectors found that both motor and pump vibrations were measured but only pump data was transcribed to the surveillance procedure. Step 7.2.6 of Procedure STP-201-6312 directed that the pump vibration readings, at locations indicated on Attachment 4 of the procedure, be recorded. However, Attachment 4 specified motor vibration locations, as shown on a drawing, but no pump vibration locations. When the inspectors brought this matter to the attention of test personnel, the inservice test engineers were contacted by the test personnel to determine which data to record. The inspectors were informed that pump data was desired.

The inspectors discussed the drawing deficiency (i.e., showing the vibration locations for the motor but not the pump) with the inservice test engineers and reviewed ASME Section XI, 1980 Edition, Article IWP-4510, "Vibration Amplitude," which specified that pump vibration data be recorded for reciprocating horizontal pumps. The inspectors determined that the inservice test engineers added Attachment 4 during a revision to Procedure STP-201-6312 on October 1, 1995. Licensee personnel noted that the faulty procedure had not been previously used; therefore, the previously collected data was the proper pump data. The inspectors reviewed selected horizontal pump test procedures and found that only the two SLC pump test procedures contained incorrect attachments.

The inspectors reviewed the trend of pump data and noted no discrepancies. The inspectors also noted that the licensee has experienced problems with the content of surveillance procedures. The failure to maintain a procedure that provides appropriate instructions for the performance of surveillance testing is a violation. However, this violation is not being cited because it meets the criteria specified in Section IV of the Enforcement Policy. Specifically, the violation is not being cited because it was considered to be of minor safety significance.

5.2 STP-204-6301 - "Division I RHR Pump and Valve Operability Test"

On November 17, 1995, the inspectors observed the inservice test of RHR Pump A in accordance with Procedure STP-204-6301. The increased frequency inservice test was conducted because the vibration levels of RHR Pump A were in the Alert range. The licensee satisfactorily performed the inservice test of the pump and removed the pump from increased frequency testing. The inspectors reviewed the completed copy of the procedure and determined that the data was satisfactorily supported removal of the pump from the increased frequency testing.

During preparation for performance of Procedure STP-204-6301, the inspectors questioned the method used to perform one of the prerequisites. Step 6.4 of Procedure STP-204-6301 stated, in part, that the licensee verify RHR Subsystem A was in the LPCI Standby Mode in accordance with Procedure SOP-0031, "Residual Heat Removal." The licensee signed off this step without having Procedure SOP-0031 in hand and without formally checking the valve lineup. The inspectors questioned the control room supervisor on this practice, who stated that the operators walked down the control room panels during shift turnover and found no discrepancies and that the operators carefully reviewed the work schedule to ensure no in-progress work affected the test. Therefore, they had adequate assurance that the system was lined up properly.

The inspectors noted that Procedure SOP-0031 also l[illegible] local manual valve positions and remote shutdown panel valve positions. [illegible]e control room supervisor stated that, during their review of logs and plant status sheets at shift turnover, none of these valves were noted to have been manipulated; therefore, adequate assurance existed to indicate that all valves were properly aligned.

The inspectors discussed the performance of Step 6.4 of Procedure STP-204-6301 with the operations manager. The operations manager stated that the intent of the prerequisite was for the performer to ensure that the system was lined up properly by whatever reasonable means the performer deemed adequate. Further, since the system was properly aligned, the method chosen by the control room supervisor was, therefore, adequate. The operations manager stated that he would evaluate the need to further enhance Step 6.4 of Procedure STP-204-6301 to determine if more explicit direction is necessary and to determine if the licensee's use of the term "verify" was used consistently during plant activities.

Based on discussions with operations personnel, the inspectors were concerned that operations management had not provided specific directions to the operating crews regarding management's expectations for verification of system status prior to performing surveillance testing. This issue will be further reviewed by the inspectors to assess management's disposition of this issue (458/9525-02).

5.3 Missed Average Power Range Monitor (APRM) Surveillances

Amendment 74 to the River Bend license, issued on August 2, 1994, changed the test frequency of a number of SRs. Previous to the issuance of Amendment 74, many APRM surveillance tests were performed each 7 days and within the scope of Procedures STP-505-4501 through -4508 (one procedure for APRMs A through H), "RPS/Control Rod Block - APRM Channel Functional Test, Channel Calibration, LSFT for 2-Loop Operation." Amendment 74 changed several of the APRM testing intervals to quarterly; however, the surveillance interval for adjusting the flow biased, thermal power trip for the APRMs remained at 7 days. Since the licensee thought that this SR also changed to quarterly, the schedule for performance of the testing was changed to quarterly.

On November 1, 1995, during a review of surveillance test procedures for the procedures upgrade program, the licensee identified that a surveillance requirement had not been properly implemented for the APRMs. TS SR 3.3.1.1.3 requires that the flow biased, thermal power trip be tested every 7 days, but the licensee had been performing the testing each quarter. The test had not been performed since October 2, 1995; therefore, the licensee entered TS SR 3.0.3, which allowed 24 hours to complete a missed surveillance without having to enter the limiting condition for operation action statement. The licensee completed the applicable portions of Procedures STP-505-4501 through -4508 within the 24-hour period and exited TS SR 3.0.3. The inspectors reviewed the completed tests and confirmed that the testing had been satisfactorily completed. The failure to perform adjustments of the APRM channels every 7 days, for calibration of the flow signals for APRMs A through H, is a violation of TS SR 3.3.1.1.3 (458/9525-03).

In December 1994, the licensee issued LER 94-29 to describe the events that occurred when all the requirements specified in TS Amendment 74 were not properly implemented. The TS amendment changed several instrument SR intervals, and the licensee individuals involved with implementing this amendment assumed that all of the instrument surveillance frequencies had been increased. However, TS 4.3.4.1 changed the recirculation pump trip test from an 18 month to a quarterly surveillance. Licensee personnel failed to appropriately note the change to the surveillance interval for TS 4.3.4.1. The corrective actions specified by LER 94-29 included: (1) revising the applicable test procedures associated with TS 4.3.4.1, (2) increasing personnel accountability in accordance with the Long Term Performance Improvement Plan, and (3) revising the process for implementing TS amendments.

Similarly, during this inspection period, the licensee noted that the requirements of Amendment 74 had again been incorrectly implemented because licensee personnel assumed that all the APRM surveillances were made less restrictive. Because of the repeat nature of this problem, the inspectors reviewed LER 94-29 and noted that the actions taken by the licensee did not include performing a review to verify all of the changes specified in Amendment 74 were correctly implemented. The inspectors determined that a thorough review should have been completed because Amendment 74 extensively revised the TS. The inspectors concluded that, had the narrowly focused corrective actions for LER 94-29 been more extensive, the error with the improper testing interval for the APRMs could have potentially been prevented.

6 ONSITE ENGINEERING (37551)

6.1 Vibration Monitoring Program

The inspectors reviewed the vibration monitoring program, as described in Procedure PEP-0003, "Vibration Program." This program required licensee personnel to periodically measure the vibration of over 100 major plant components, including both secondary plant and safety-related pumps. The vibration monitoring program included the 34 pumps listed in the inservice test program. Equipment used by licensee personnel to measure component vibration included a microprocessor controlled vibration analyzer for data acquisition and a desktop computer for data analysis and report generation. The inspectors considered the licensee's efforts in monitoring the vibration performance of safety-related pumps to be excellent.

6.2 Riley Temperature Switches

After an inadvertent RCIC isolation, which is discussed in Section 2 of this report, the inspectors discussed the failures of the temperature switches with engineering personnel. The temperature switches were installed at boiling water reactor power plants since original construction and failures have occurred frequently. Since the switches typically detect temperatures from thermocouples with low voltage outputs, the switches are susceptible to noise in adjacent circuitry. Consequently, the temperature switches have caused inadvertent isolations when adjacent circuitry was undergoing maintenance or testing.

The licensee was pursuing upgraded replacement temperature switches that would not be as susceptible to noise by engineering installing the new temperature switches in ambient temperature applications and monitor the results to determine reliability. Licensee personnel plan to begin the trial temperature switch replacement during the upcoming refueling outage and, if successful, will replace additional temperature switch units during power operations, in other than ambient temperature locations. In addition, the requirement for differential temperature monitoring of the rooms will be evaluated for omission from the Technical Requirements Manual, which will require reliance on ambient temperature or high flow signals to provide the required isolations. In the interim, licensee personnel revised maintenance procedures to help reduce noise when working near temperature switches and the temperature switches are bypassed when testing or taking readings on adjacent switches. The inspectors considered the licensee's actions to address this issue to be proactive.

6.3 Potential for Operation In An Unanalyzed Condition

On November 3, 1995, the licensee identified a potentially unanalyzed condition. During a review of the fuel vendor's reload analysis, reactor engineering personnel noted that a letter from the vendor indicated that the Cycle 7 (the current operating cycle) load line limit analysis had not been revalidated. The load line limit analysis allowed operation up to the 104.2 percent rod line, providing the licensee more flexibility in power maneuvers. Without this load line limit analysis, the licensee could only operate up to the 100 percent rod line. The licensee initiated Condition Report 95-1050 to document this oversight and to provide for further followup.

The licensee evaluated whether this concern existed during previous operating cycles and found that the reload analyses for Operating Cycles 3, 4, 5, and 6 had the block for load line limit analysis checked "NO." This was of concern because the licensee operated at the 104 percent rod line during each of these previous cycles. The licensee initially concluded that they had operated in an unanalyzed condition for Operating Cycles 3, 4, 5, and 6. Subsequently, the licensee determined that this concern had no safety significance because the severity of the most limiting accidents depended on the value of the minimum critical power ratio. Further, the licensee had always operated within the minimum critical power ratio limits with sufficient margin. The licensee determined that this event was not reportable because it was not an unanalyzed condition that significantly compromised plant safety. The inspectors reviewed the licensee's reportability evaluation and determined that it was satisfactory.

The licensee subsequently reviewed vendor document GESTAR S5.2.2 and noted that this document indicated that the load line limit analyses were generically provided for BWR-5s and -6s and were not required to be revalidated on a cycle specific basis. The licensee contacted the vendor, who agreed with the conclusions; therefore, the licensee did not operate in an unanalyzed condition at any time.

For followup, the inspectors interviewed the reactor engineering supervisor and questioned why this discrepancy had not been previously documented. The reactor engineering supervisor stated that he was recently transferred to the River Bend Station and had thoroughly reviewed the vendor's reload analysis to familiarize himself with the site specific requirements. The inspectors noted that, although this issue had no safety significance, it emphasized the need for detailed reviews of vendor supplied information to ensure that correct analyses and documentation are supplied.

7 PLANT SUPPORT ACTIVITIES (71750)

7.1 Fire Protection

The inspectors reviewed the status of fire fighting equipment and the controls for conformance with administrative procedures. Within the scope of this inspection, the licensee's fire protection programs appeared to be satisfactory. However, the inspectors had the following observations

On October 30, 1995, the inspectors walked down selected emergency lights to determine if the licensee properly maintained the emergency lights charged, located, and aimed. The inspectors used the fire safe shutdown analysis, Criterion Number 240.201A, Appendix M, "River Bend Station 10 CFR 50, Appendix R, Separation Analysis - Emergency Lights," as guidance for the inspection. The inspectors found all of the selected emergency lights to be properly charged. With one exception, the inspectors found all of the selected emergency lights to be properly located and aimed.

Emergency Light 1LAP-1X6-9-0-A-2, located on the east wall of the Auxiliary Building at the 141-foot elevation, was not located or aimed properly. Appendix M of the safe shutdown analysis showed this light to be located just southwest of Panel 1EHS*MCC2D and aimed towards this panel. However, the inspectors found Emergency Light 1LAP-1X6-9-0-A-2 located northwest of and aimed away from Panel 1EHS*MCC2D. The inspectors notified the licensee of this discrepancy.

The licensee informed the inspectors that Panel 1EHS*MCC2D was not used for any actions for any safe shutdown scenario; therefore, this finding had no safety significance. The inspectors reviewed the licensee's safe shutdown procedures and agreed with the licensee's assessment. The licensee stated that the drawing in Appendix M of the safe shutdown analysis was in error and would be corrected. The licensee also stated that they had just completed walkdowns of the facility for proper locations of emergency lighting and additional corrections were being made to the drawings in Appendix M. The inspectors concluded that the licensee's actions were satisfactory.

On November 15, 1995, during a tour of the auxiliary building, the inspectors noted that, on the 95-foot elevation, scaffolding had been erected such that it interfered with the beam of an emergency light. The inspectors informed the shift supervisor, who documented this observation and contacted the carpenters who relocated the scaffold. The inspectors discussed this observation with the plant manager. The plant manager stated that he would ensure that there was increased management presence in the plant prior to the outage to ensure outage preparations do not affect plant operation or the capability to respond to an emergency condition.

7.2 Radiation Protection

On November 8, 1995, the inspectors observed personnel exiting the radiological controls area. The inspectors observed that a number of personnel alarmed the portal monitor during their initial attempt to exit the area. The radiation protection technician present requested that these individuals perform a partial frisk of the alarming areas using the hand held instrumentation. The inspectors noted that three of the individuals did not frisk their hands prior to picking up the frisker probe, as required by the radiation protection posted guidelines. The inspectors notified the radiation protection technician, who instructed the three individuals on the proper frisking methods and stated that he would closely monitor personnel frisking practices at the radiological controls area exit. The inspectors deemed these actions appropriate. The inspectors also noted that there was no spread of contamination and, as a result, no safety significance as any contamination would have been identified by the personnel monitors.

7.3 Plant Housekeeping

During the plant tours, the inspectors observed the plant materiel condition and equipment storage to determine the general state of cleanliness and housekeeping. Housekeeping was observed to be good during this inspection period.

8 MAINTENANCE FOLLOWUP (92902)

8.1 (Closed) Inspection Followup Item 458/9331-01: Control Building Air Conditioning Failures

In December 1993, the licensee entered TS 3.0.3 on two occasions because all four trains of the control building air conditioning became inoperable. Each of the two divisions has two redundant chillers and one chiller per division was required to be operable. These entries into TS 3.0.3 resulted from combinations of planned maintenance, chillers tripping, and system lineups.

The inspectors previously followed up on the licensee's corrective actions in NRC Inspection Report 50-458/95-01. The inspectors noted at that time that all of the corrective actions were completed except the modification to install the first out lock-in alarm to display the cause of the air conditioning unit trips. In addition, NRC Inspection Report 50-458/95-01 listed a licensee commitment to evaluate the need for an abnormal operating procedure to cover loss of control building air conditioning.

In November 1995, the inspectors reviewed the outstanding corrective actions. The inspectors noted that the modification displaying the cause of the air conditioning unit trips was installed and functional. Operations personnel demonstrated proficient use of this modification when one of the chillers tripped in November 1995. The inspectors considered the licensee's actions to be satisfactory to address this concern.

In addition, the licensee continued to develop a new abnormal operating procedure for loss of control building air conditioning at the end of the inspection period. Since this item was opened, the licensee has implemented Improved TS, which changed the limiting condition for operation for the control building air conditioning. With one division of control building air conditioning inoperable, the licensee had 30 days to return it to an operable status, with both trains inoperable, licensee has 7 days to restore one of the units to an operable status. However, the licensee decided they still need a procedure to address this casualty since they want to maintain the control building air conditioning. With this information, the inspectors concluded that the licensee's evaluation was satisfactory.

8.2 (Closed) Violation 458/9415-04: Failure to Perform Independent Verification

During maintenance to replace a relay associated with the lower containment airlock system, the inspectors noted that the individual performing the work landed the leads and removed the lifted-lead tags during the restoration process, which was contrary to Procedure GMP-0042 "Circuit Testing and Lifted Leads and Jumpers." Procedure GMP-0042 required independent verification of all lifted leads on restoration and that the independent verifier remove each lifted lead tag upon completion of each individual verification.

The inspectors expressed concerns to licensee management following discussions with the technicians and the cognizant supervisor regarding the lack of knowledge of Procedure GMP-0042 requirements. The licensee agreed that the procedure required independent verification and stated that the involved individuals would receive counseling and be trained on those requirements. Additionally, the licensee stated that a revision to the procedure was being considered.

In response to this violation, the licensee performed the independent verification step to ensure the leads were properly landed. The supervisors and electrical technicians of the plant modifications and construction groups were briefed on expectations and were provided a proper interpretation of the independent verification requirements. A general version of this briefing was extended site-wide through the use of the licensee's communications bulletin. In addition, the procedure was scheduled for a revision to clarify the general requirements.

The inspectors reviewed documents associated with the specific and site-wide training. Procedure GMP-0042 was also reviewed. The inspectors found that the licensee had performed appropriate training, adequately revised the procedure, and reviewed additional electrical procedures pertaining to lifted leads and jumpers to address the causes of the violation and prevent recurrence.

9 ONSITE REVIEW OF AN LER (92700)

(Closed) LER 458/95-08: RCIC System Isolation Due to Spurious Trip of Temperature Switch

The inspectors performed a review of this LER and determined that the LER provided a sufficient description of the event, identified the root causes, and included corrective actions to prevent recurrence.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

W. R. Brian, Manager, Strategic Planning
E. C. Ewing, Manager, Maintenance
J. J. Fisicaro, Director, Nuclear Safety
J. O. Fowler, Supervisor, Quality Assurance
T. O. Hildebrandt, Manager, Outage Management
G. C. Hockman, Quality Specialist
H. B. Hutchens, Superintendent, Plant Security
R. T. Kelly, Supervisor, Instrumentation and Controls
M. A. Krupa, Manager, Operations
T. R. Leonard, Director, Engineering
D. N. Lorfing, Supervisor, Licensing
J. R. McGaha, Vice President-Operations
M. B. Sellman, General Manager, Plant Operations
A. D. West, Supervisor- Radiation Control
R. G. West, Manager, System Engineering
G. A. Zinke, Manager, Quality Assurance

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

2 EXIT MEETING

An exit meeting was conducted on December 6, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee stated that vendor document GESTAR S5.2.2, which was provided to the inspectors and discussed in Section 6.3 of this inspection report, was proprietary. This inspection report does not contain any proprietary information.