ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/95-23

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: July 30 through September 9, 1995

Inspectors: W. F. Smith, Senior Resident Inspector
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Approved: C. A. VanDenburgh, ~~Chief~~, Project Branch D 9-22-95 Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of licensee actions in response to events, plant operations, maintenance and surveillance activities, onsite engineering, plant support activities, followup on corrective actions for violations, and review of licensee event reports (LER).

Results:

Plant Operations

- The senior reactor operators maintained good command and control over control room activities during the reduction in power from 100 to 65 percent on August 4, 1995, for balance of plant repairs. The inspectors also noted good reactor engineering support and strong operations management oversight (Section 3.1).

- Shift turnovers were conducted in accordance with established procedures, and the general control room formality was consistently commensurate with the activities in progress (Section 3.1).

- The licensee's response to NRC's concerns about routine bypassing of the reactor water cleanup (RWCU) isolation feature during normal system operations was appropriate. Proper consideration was given to the necessity and safety benefit of this practice (Section 3.3.1).

Maintenance

- The licensee's paint supervision demonstrated poor work control in that the Division II diesel generator (DG) cooling air vents were covered without taking adequate compensatory action. Although the DG was in standby at the time and an individual had been tasked to remove the covers if the DG started, a violation was identified for the failure to control this activity with an approved procedure (Section 3.3.2).

- The inspectors noted several performance problems that had not been observed in recent months. During the replacement of the air start solenoid operated valve (SOV) on the Division I DG, the mechanics started work on the wrong valve, contrary to the work instruction. This concern was heightened because they had been cautioned by the inspectors prior to the start of work. In another example, the supervisor failed to initiate a condition report (CR) to document this error until two days later when prompted by the inspectors. Both examples were cited as a violation (Section 4.4).

- Based on the preliminary results of an on-going failure analysis, a possible cause of the DG air start SOV failure was eccentricity between the upper and lower operating cylinders of the SOV. Because of the possible generic implications of this finding, an Inspection Followup Item was opened to track the licensee's final resolution (Section 4.4).

- Surveillance testing observed by the inspectors was conducted in a professional manner with good communications, excellent procedure adequacy and compliance, and satisfactory test results (Section 5).

Engineering

- The inspectors noted excellent engineering support and strong management oversight through the prompt establishment of a significant event review team (SERT) following the catastrophic failure of the high-pressure core spray (HPCS) pump room cooler fan. The licensee developed an aggressive corrective action plan that involved evaluating three alternatives in parallel to assure a timely restoration of the HPCS safety function (Section 2.1).

- The inspectors concluded that the licensee took an adequate engineering approach to resolving ASME Code and regulatory issues related to a pressure boundary leak found in the penetration valve leakage control system (PVLCS) pipe connection to a feedwater stop valve. The licensee's approach allowed continued safe operation of the plant and was consistent with ASME Code and NRC regulatory requirements (Section 2.2).

- The licensee's Procedures Upgrade Project personnel demonstrated good attention to detail by identifying technical inadequacies in the semi-annual hydrogen igniter surveillance test procedure. By analyzing historical data, the engineering personnel determined that the correct number of igniters were operable; therefore, the safety significance was low. In addition, the inspectors identified two minor discrepancies in the historical data, which were subsequently corrected. A noncited violation was identified (Section 6.1).

- The licensee was unable to retrieve the 18-month hydrogen igniter surveillance test data completed during Refueling Outage 5, after it was requested by the inspectors for review. This was a violation of Technical Specification (TS) 6.10.2.d, which requires these records to be retained for at least 5 years. The completion certification sheet was eventually recovered. Therefore, this was a minor violation, which was not cited (Section 6.1).

Plant Support

- The material condition of the plant and housekeeping practices continued to improve (Section 3.2).

- The security organization continued to perform well in accordance with the licensee's security plan. Appropriate attention was focused on maintaining protected area integrity during construction activities associated with the new engineering building (Section 7.1).

- Radiation Protection (RP) personnel demonstrated good attentiveness to proper radiation postings by promptly identifying discrepancies and taking comprehensive corrective action to preclude recurrences (Section 7.2).

Summary of Inspection Findings:

- Violation 458/9523-01 was opened (Section 3.3.2).

- Violation 458/9523-02 was opened with two examples (Section 4.4).

- Two noncited violations were identified (Section 6.1).

- Inspection Followup Item 458/9523-03 was opened (Section 4.4).

- Violation 458/9422-05 was closed (Section 8.1).

* Violation 458/9502-01 was closed (Section 8.2).
* LER 458/94-031 was closed (Section 9).

Attachments:

* Attachment 1 - Persons Contacted and Exit Meeting
* Attachment 2 - List of Acronyms

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the plant was operating at 100 percent power. On August 4, 1995, power was reduced to 65 percent to accommodate repair of a main condenser tube leak, to repair steam leaks, and to accomplish reactor control rod scram testing. Power was restored to 100 percent on August 6. On August 11, power was reduced to 80 percent for routine reactor control rod reconfiguration. By August 12, power was restored to 100 percent. On September 3, power was reduced to 95 percent to reduce the evaporation rate in the main cooling towers. This was necessary until the licensee successfully reseated an air relief valve in the nonsafety related makeup water system that malfunctioned while shifting makeup water pump suction strainers. The malfunction caused a reduction in makeup water to the cooling towers. By September 4, approximately 6 hours later, power was restored to 100 percent. The plant then operated at 100 percent through the end of this inspection period.

2 ONSITE RESPONSE TO EVENTS (93702, 37551)

2.1 Catastrophic Failure of the HPCS Pump Room Cooler Fan

On September 5, 1995, Unit Cooler HVR*UC5, which supplied cooling air to the HPCS pump room, tripped off. The plant was running at 100 percent power at the time. An operator was dispatched to investigate and found the vaneaxial fan and 40 horsepower motor lying in the bottom of the cooler plenum. There was extensive damage to the motor, the fan hub casting was fractured, and all of the fan blades were broken off. The fan shroud, mounted on top of the cooler, was expanded out in one location where the fan may have contacted it. Because of inertial forces, the motor broke loose from its supports in the shroud and fell to the bottom of the cooler plenum. One fan blade punctured the cooler plenum but did not go all the way out. There was no damage to any equipment adjacent to the cooler, and the cooling coils were not damaged. The inspectors observed the damaged parts, and it appeared that the cast aluminum fan hub fracturing was the cause of the event.

The operators appropriately declared the HPCS system inoperable because no other pump room cooling was available. In accordance with TS 3.5.1, the allowed outage time for HPCS was 14 days, provided reactor core isolation cooling and Divisions I and II emergency core cooling systems were maintained operable. Within 4 hours, the licensee reported the event as a loss of safety function of a single train system pursuant to 10 CFR 50.72.

The licensee established a SERT to implement the root cause and corrective action determination and to coordinate timely restoration of the HPCS safety function. The SERT promptly established a plan of action with three parallel paths. The first was to dedicate a spare nonsafety-related (but identical) fan shroud and fan for safety-related use and to purchase a safety-related and qualified 40 horsepower motor from the manufacturer. The second action path was to dedicate the same spare nonsafety-related fan assembly for safety-related use, including a design change to use the spare nonsafety 50 horsepower motor. This path had the best potential for implementation because all of the parts were on hand. However, a design change needed a detailed engineering evaluation of the cabling capacity and standby DG loading profiles. The third action path was to determine if the HPCS pump could operate without the pump room cooler. This involved evaluating the heat load calculations with no cooling.

As of September 7, preliminary calculations had determined that the motor could overheat. Also, the licensee informed the inspectors that the damaged fan and motor were being considered for repair However, the licensee estimated that the repairs could not be completed in time to meet the HPCS allowed outage time. Subsequently, on September 10, the licensee restored HPCS to an operable status. The 50 horsepower nonsafety-related spare fan and shroud assembly were dedicated and qualified for the safety-related application.

The licensee demonstrated good engineering support and strong management oversight for this problem. Actions were thorough and well developed, and the Facility Review Committee was involved in the safety decisions.

2.2 Steam Leak Found in an ASME Code Class 2 Boundary

On September 2, 1995, during a routine inspection for leaks of piping and components in the steam tunnel, the licensee identified a pinhole leak on a weld to the body of a 20-inch feedwater stop valve (B21*MOVF065B). The leak was located in the toe of the weld attaching a 1-inch Schedule 80 pipe entering the bottom of the valve body between the disks. This was a small leak with approximately a 12-inch plume of feedwater flashing to steam. The pinhole was on the piping side of the weld and not the valve body. The valve was located upstream of the outboard containment isolation valve and had no safety function except to provide an entry point for the Division I PVLCS. Therefore, the valve and the connected PVLCS piping was safety-related, ASME Code Class 2. The piping upstream of the valve was designated nonclass piping.

The operators declared Division I PVLCS inoperable. In accordance with TS 3.6.1.10, the allowed outage time was 30 days, after which the plant was required to be shut down. Licensee management established a SERT to assure proper engineering approaches to this problem and to coordinate any licensing or regulatory interfaces.

The SERT determined that repair of the leak would require shutting down the plant and draining that portion of the feedwater system to facilitate welding. In addition, the SERT noted that NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping," did not allow the application of liquid sealants and pipe-encapsulating cans for temporary non-Code repair on this piping in order to restore operability.

Furthermore, Section 6.15 of the technical guidance provided by Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," states, in part, that upon discovery of leakage from a Class 2 component pressure boundary, the licensee should declare the component inoperable, which they did. ASME Section XI, 1980 Edition with Addenda through Winter, 1981, which applied to River Bend, did not appear to have guidance on how to address leaks found during plant operations; however, hydrostatic test failures cannot be corrected with liquid sealant. In order to delay the permanent weld repair until the refueling outage in January 1996, the SERT took the following approach:

- A temporary alteration (design change) was implemented to isolate the feedwater stop valve and the leak from the PVLCS by closing the PVLCS isolation valve for that branch line at manual isolation Valve LSV*V33. Engineering calculations reviewed by the inspectors demonstrated that, if the pipe broke completely off during a design basis accident, there was sufficient margin to comply with the offsite dose limits of 10 CFR 100. This action restored PVLCS Division I to an operable status and enabled the plant to exit TS 3.6.1.10.

- With feedwater stop Valve B21*MOVF065B no longer having a safety function, the engineers established the acceptability of the degraded condition for continued power operation.

- The licensee planned to implement a temporary leak repair by applying a liquid sealant on the leaking pipe weld in order to stop or reduce further degradation of the leak from steam cutting and erosion.

The above approach was supported with engineering evaluations performed in accordance with 10 CFR 50.59, which in turn were approved by the Facility Review Committee. The inspectors reviewed the documentation and discussed it with specialists in Region IV Division of Reactor Safety. The inspectors concluded that the licensee's approach was consistent with ASME Section XI and NRC regulatory requirements and did not constitute a threat to the health and safety of the public.

3 PLANT OPERATIONS (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with regulatory requirements, to ensure that the licensee's management controls effectively discharged the licensee's responsibilities for continued safe operation, and to evaluate the effectiveness of the licensee's self-assessment programs.

3.1 Control Room Observations

On August 4, 1995, the inspectors observed control room activities while the operators reduced power from 100 percent to 65 percent. The operators lowered reactor power to approximately 73 percent by decreasing recirculation flow and then to 65 percent by inserting control rods. The shift superintendent and the control room supervisor maintained good command and control of control room activities and provided concurrence prior to inserting control rods. Also, the operators utilized closed-loop, formal communications throughout the evolution.

Two reactor engineers were present and provided technical advice for conservative reactivity manipulations. The Operations Manager was present in the control room and observed the power reduction. The inspectors concluded that the power maneuver progressed as planned and without incident.

The inspectors observed control room shift turnovers on August 2 and 22. The turnovers were conducted in a formal manner followed by a shift briefing for all on-coming personnel. The inspectors considered the conduct of the shift turnovers and the guidance contained in Operations Section Procedure OSP-0002, "Shift Relief and Turnover," Revision 11D, to be satisfactory.

3.2 Plant Tours

On August 4, 1995, the inspectors selected two Division I systems, main steam positive leakage control system and PVLCS for walkdowns. These two systems were required to be operable during power operation. In addition, the redundant Division II systems were inoperable because of preventive maintenance (PM) in progress. The inspectors verified that the valve alignments were correct and that the valves were properly labeled as documented in System Operating Procedures SOP-0034, "MSIV Sealing System (Positive Leakage Control)," Revision 6 and SOP-0041, "Penetration Valve Leakage Control System," Revision 12. The inspectors concluded that the two systems were operable based on the physical condition of the systems and because all of the accessible valves were in the correct position and labeled properly.

During plant tours the inspectors noted that, in general, the material condition of plant components was good. Particularly noteworthy was the absence of oil leaks on the DGs and the recirculation flow control valve hydraulic power units. The inspectors found that components with minor deficient conditions, such as valve packing leaks, were properly identified for corrective maintenance. However, on August 23 the inspectors noted a corroded support for the Division I standby battery. This condition was not identified with a deficiency tag. The inspectors informed licensee engineering personnel of the deficiency. Although a bolt and support beam exhibited signs of acidic corrosion, the condition was not severe and did not affect the ability of the equipment to operate properly during a seismic event. The licensee generated CR 95-0850 to address this condition.

3.3 Licensee Management Controls

3.3.1 Bypassing Isolation Features During RWCU System Operations

During an August 2, 1995, visit to the site, the Director, Office of Nuclear Reactor Regulation (NRR), observed the control room operators placing a RWCU filter-demineralizer in service. The evolution was being executed in accordance with System Operating Procedure SOP-0090, "Reactor Water Cleanup System (Sys. #601)," Revision 13C. The Director, NRR, questioned the necessity for bypassing the automatic containment isolation signal during routine operations.

Upon further evaluation, the inspectors noted that System Operating Procedure SOP-0090 allowed the operator, as an option, to place RWCU Isolation Bypass Switches E31A-S1A and -S1B in "bypass" when starting an idle RWCU pump and removing/returning a filter-demineralizer from/to service. Typically, the operators bypassed the automatic isolation signal during these circumstances because numerous invalid RWCU system isolations had previously occurred early in the life of the plant.

The licensee explained that this practice prevented an automatic isolation on a high differential flow, which often resulted from system flow transients and perturbations. The feature was bypassed within the two-hour time constraint of the TS 3.3.2 limiting condition for operation action statement. In addition, the licensee indicated that the use of the bypass prevented challenges to the isolation logic. Invalid isolations may result in additional thermal and pressure stresses to the piping and pump seals or possibly cause a loss of filter-demineralizer beds. Also, restarting RWCU pumps tripped by the isolation required operator entry into the pump room, a locked high radiation and contaminated area, to manipulate valves and warm the pumps. The increased personnel radiation dose could otherwise be avoided by utilizing the bypass. The licensee further explained that the 12 control room annunciators associated with the bypassed isolation feature were operational while in bypass; thus, the operators closely monitored them for the presence of a valid isolation signal so they could respond in a timely and appropriate manner.

Nevertheless, in response to this concern, the licensee issued Standing Order 125 on August 11, 1995, directing the operators to not use the bypass option during the above circumstances when in Modes 1, 2, and 3, until an evaluation of the net safety benefit of this option was completed.

On August 30, the licensee completed the above evaluation and determined that the functions that had been bypassed during the above RWCU operations were not assumed to be operable in any Updated Safety Analysis Report transient or accident analysis and that bounding analyses were performed for large breaks. The licensee did not have any recorded data to show whether or not the isolation would actually have occurred during the above operations. A 45-second time delay was designed into the system to prevent invalid isolations during the above operations. Some of the operators remembered getting an alarm on the timer commencing, but they did not remember getting an alarm on the isolation signal.

The licensee decided to resume the practice of bypassing the RWCU isolation feature until Refueling Outage 6, which commences on January 6, 1996. This translated to approximately eight operations involving filter/demineralizers. During these operations, the licensee stated that they would record the times the 45-second timer was activated and whether or not it timed out, thus calling for an isolation. If they establish confidence that there was sufficient margin before timer time-out, Procedure SOP-0090 would be revised to remove the option that allowed bypassing during filter-demineralizer operations.

On September 1, while restoring from the process of precoating and backwashing RWCU Filter/Demineralizer A, the operators noted that the 45-second timer was activated for a maximum of 3 seconds in one instance. On September 8, during the same operation with RWCU Filter/Demineralizer B, the 45-second timer did not activate at all, thus indicating that there will probably be sufficient margin to leave the RWCU isolation feature operable after several more data points are taken. The licensee indicated that the option to bypass the RWCU isolation during pump starts would remain in effect until a similar confidence level had been established. The licensee indicated that establishing confidence during RWCU pump starts may take longer because pump starting while the plant was operating was considered to be an infrequent evolution.

The inspectors considered the licensee's approach to the NRC's concern appropriate to the circumstances. The inspectors concluded that the licensee had been and continued to work around the automatic bypass features of the RWCU system. However, the system had little impact on safety during accident conditions, and the licensee had established a schedule for resolving the concern.

3.3.2 DG B Inappropriately Masked During Painting Activity

On August 31, 1995, during a plant tour, the inspectors found the Division II standby generator cooling air intakes and outlets had been completely covered with plastic sheeting and masking tape. The painters were preparing the DG for painting and had installed the plastic to protect the generator internals from paint overspray. The inspectors immediately contacted the control room and noted that the control room operators considered the DG to be operable but were not aware that the generator cooling air vents were totally covered. Immediate corrective action included removing all masking and terminating painting of operable safety-related components until the controls and precautions for painting could be reevaluated and corrected.

The controls that the licensee had placed in effect for painting DG B consisted of an interoffice memo, dated February 24, 1995, from the technical specialist in charge of the painting of DG A. The memo contained several precautions to be followed when painting DG A, based partly on problems that occurred at other plants. These precautions were applied to the painting of

DG B; however, they did not specifically address masking of the generator cooling air vents.

On August 31, in response to the problem identified above, the memo was amended to include direction to station a full-time watch to quickly remove masking from the generator screens if the DG started. The licensee explained that, although it was not previously documented, a person had been verbally instructed by the paint foreman to be prepared to immediately remove the covering from the generator if the DG should start.

The inspectors acknowledged that the individual probably would have acted appropriately to sustain operability of the DG if it had started; however, the guidance provided by NRC Generic Letter 91-18, Section 6.7, "Use of Manual Action in Place of Automatic Action," was not applied. For example, written procedures were not in place, and a full consideration of all pertinent differences was not made. Painting supervision apparently recognized the potential of rendering the DG inoperable but failed to inform the operators of the actions they had taken to sustain operability of the safety-related components. This prevented the operators from implementing the controls delineated in Operations Policy 19, "Restoration/Maintenance of System/Component Operability Through Use of Manual Action in Place of Automatic Action," Revision 0. This policy implemented the guidance provided by Generic Letter 91-18, in response to a previous problem where manual action was in appropriately substituted for automatic action. Reference NRC Inspection Reports 50-458/93-28 and 50-458/94-22.

The inspectors concluded that the safety significance of the specific violation was low because the DG probably could have been restored to an operable status by the person assigned to remove the covering if the DG started. The principal concern discussed with the licensee was that plant staff working on and around safety systems and components and impacting operability failed to inform the operators so that the appropriate decisions could be made consistent with policies, procedures and the operating license.

The failure to establish procedural guidance on taking manual actions to sustain operability of the DG was contrary to Operations Policy 19, and is a violation of TS 6.8.1.a (458/9523-01).

4 MAINTENANCE OBSERVATIONS (62703)

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

MWO Number	Description
R220624	Troubleshooting Division I DG Reactive Load Oscillations
P582192	Calibration Check of Division II DG Pressure Switches
R214183	Replace corroded packing gland fasteners and replace packing on Standby Service Water (SSW) Pump SWP*P2C
R218051	Replace Division I DG Air Start SOV EGA*SOVY11A
P585136	Insulation resistance checks on the Division III DG

The inspectors found no significant strengths or weaknesses during the observations, except as noted below:

4.1 MWO R220624 Division I DG Troubleshooting

On June 23, 1995, an operator observed abnormal reactive load oscillations on the Division I DG during its normal monthly surveillance. The oscillations were slow, sporadic, and of a low magnitude. The operator initiated CR 95-0650. System Engineering and maintenance performed troubleshooting activities, which included running the motor-operated potentiometer throughout its range to check the potentiometer resistance profile and inspecting the voltage regulator and potential transformer electrical connections. The electricians found the potential transformer connection fingers were dirty with one out of alignment, and the fuse holders were loose. These problems were corrected by the electricians, and operators repeated the surveillance test. No abnormalities were noted by the operators during this test.

System Engineering concluded that the problems identified with the potential transformer could have caused the sensed voltage seen by the voltage regulator to fluctuate. Based on the completed corrective maintenance and the satisfactory results from the surveillance test, System Engineering considered the DG to be fully capable of performing its specified function.

On July 19, the operators again observed abnormal reactive load oscillations on the Division I DG during the monthly surveillance test. The operators issued CR 95-0726. System Engineering performed an operability assessment which stated that either the grid voltage was fluctuating with load changes, causing the reactive load changes, or an unknown and undetected intermittent degradation existed in the static exciter voltage regulator assembly. System Engineering determined that during the surveillance, the grid load was increased by 733 megawatts and concluded that this grid change could have resulted in a slight grid voltage change causing the observed reactive load changes. Also, System Engineering discovered there was a grid transient during the June 23 surveillance, when a 400 megawatt unit went off line.

System Engineering determined that the maximum observed reactive load change while the DG was parallel to the grid was a 1000 kilovar change that equated to a voltage change of less than ±34.65 volts. This maximum voltage change was about one-twelfth of the TS limit of 416 volts.

System Engineering developed a test plan and schedule that had the operators starting and synchronizing the DG to the grid early on a Monday morning. System Engineering considered Monday mornings to be when the grid was most unstable because industrial plants would be starting up causing grid fluctuations.

On July 31, the operators observed reactive load oscillations for the third time on the DG. The inspectors observed electricians and system engineers perform troubleshooting activities in accordance with MWO R220624. During troubleshooting activities, an electrician identified two wires pinched between the cover on the motor-operated potentiometer case and the back wall of the panel. One wire was a spare and the other wire supplied a signal to the voltage regulator. System Engineering determined that a ground on the second wire could result in a slightly biased voltage to the error amplifier in the voltage regulator, with additional resistance load for the voltage regulator synchronizing phase comparators, and with an additional load in competition with the generator field. These false signals could have caused the observed oscillations.

The electricians demonstrated excellent verification techniques. The electricians went beyond the requirements and performed independent verification prior to lifting leads. The electricians also demonstrated good attention to detail by identifying the pinched wires. The electricians revised the job plan and repaired both wires.

After the repairs were completed, the operators synchronized the DG to the grid and did not observe any oscillations. The operators successfully completed the surveillance test and declared the DG operable.

The licensee stated that, even though the pinched wires could have been a cause of the fluctuations in reactive power on the DG, they planned to instrument the DG during future surveillance runs to obtain more data on the effects of grid transients on the DG while it was paralleled to the grid. The inspectors will monitor the results of this activity.

4.2 MWO P582192 Division II DG Pressure Switches

On August 2, 1995, the inspectors observed maintenance technicians verifying the calibration of three Division II DG pressure switches in accordance with MWO P582192. Pressure Switches 1EGS*P512B, -13B, and -75B provided control room and local alarms during an overspeed event.

The inspectors verified that the danger-hold tags for Clearance RB-95-0618 were properly placed and the operators configured the equipment in the position listed on the tags. The maintenance technicians demonstrated good communication skills and verification techniques during the PM. The maintenance technicians found all three pressure switches within the calibration limits.

4.3 MWO R214183 Repack SSW Pump C

On August 16, 1995, the inspectors observed portions of the replacement of corroded packing gland fasteners and repacking of SSW Pump SWP*P2C. The mechanics performed well as they encountered difficulty in removing the corroded packing gland follower. The parts were removed successfully without damaging the pump. The shaft sleeve showed signs of wear from packing friction, and CR 95-0823 was initiated by the system engineer, who came to the job site to evaluate the condition of the pump. He concluded that the wear was not significant and would not have an adverse affect on the operability of the pump. The CR documented the condition and provided for long term corrective action, i.e., repair or replace the sleeve during an outage.

The inspectors noted that the clearance was adequate and procedures were followed. However, the work package contained a discrepancy on the material list which caused some delay in starting the job. For the replacement packing, the parts list called for Nuclear Class 2, and the stores requisition showed Class 2 as being supplied, as confirmed on the packing container. However, the pump bill of material called for Nuclear Class 1. With the help of Quality Assurance, the disparity was cleared up by obtaining, from the files, approved Safety Classification Form SCF 098, which supported the downgrade. The inspectors expressed concern that with the crafts verifying their own material, more straight forward information should be provided in the work packages. The licensee explained that extensive efforts were underway to provide an accurate engineering bill of material that reflected the correct part quality and requisition number, which will simplify verification of correct parts for safety-related components. Concurrent with these efforts, parts were being validated in the warehouse to assure the correct parts were available as needed.

4.4 MWO R218051 Replacement of DG Air Start SOV

On August 16, 1995, the inspectors observed the replacement of air start SOV 1EGA*SOVY11A, which was designed to admit 250 psi starting air from the forward air receivers to the common starting air manifold on the Division I DG. This repair activity was in response to a failure of the DG to start during a surveillance test. A normal start signal was initiated with the rear air receivers isolated to verify that the DG would start on the forward air receivers. The system engineer was present during the failure and determined, after reviewing the event, that the forward air start SOV failed to fully open, with the possibility that the upstream strainers may have become clogged. The MWO was written to inspect the strainers and/or replace SOV 1EGA*SOVY11A.

The inspectors identified problems with this maintenance activity that were not typical of observations during the past few months. These were discussed with licensee management so that appropriate actions could be taken to prevent a recurrence.

Specifically, the inspectors had observed a mechanic surveying the job site prior to receiving the work package. When questioned, the mechanic pointed out the components he would be working on. After the mechanic left, the inspectors took a closer look and found that the mechanic had incorrectly pointed to the rear air components, when the failure had occurred on the forward air subsystem. Subsequently, in the shop, the inspectors alerted the mechanic about pointing at the wrong valve. In response, the mechanic assured the inspectors that the written instructions would be followed. As the job was commencing, the inspectors observed the mechanics erroneously loosening the pilot air supply tubing fitting on the rear starting air valve. By the time the inspectors reached the platform to challenge this activity, the mechanics had moved to the correct, forward air start SOV. Upon questioning the supervisor, who was at the job site, the inspectors determined that the mechanics did start on the wrong valve, but the mechanics retightened the tubing fitting after the supervisor recognized the error and redirected the work to the forward air start SOV. Although the supervisor took action to stop the incorrect work, the inspectors were concerned that the error occurred after alerting the mechanics about the possibility of working on the incorrect valve even though both valves were clearly labeled and the MWO was correct. The failure to follow MWO R218051 is a violation of TS 6.8.1.a (458/9523-02, Example 1).

The inspectors also noted that the licensee had not written a CR to document this problem until prompted by the inspectors on August 18th. The inspectors expressed concern to licensee management about plant staff not promptly identifying and documenting an error such as the above. The inspectors indicated that the licensee needed to know when unexpected work was performed on a safety-related structure, system, or component in order to evaluate the impact on plant safety. Also, the work, the restoration, and any required retest needed to be documented prior to declaring the affected safety system operable. The inspectors noted that River Bend Nuclear Procedure RBNP-030, "Initiation and Processing of Condition Reports," Revision 7, Section 5.1, Attachment 1, required a CR to be written when performing activities on the wrong equipment because of personnel error. The failure to follow Procedure RBNP-030 is a violation of TS 6.8.1.a (458/9523-02, Example 2).

The strainers upstream of the SOV were clean and dry and did not appear to be the cause of failure; therefore, the SOV was replaced. The mechanics experienced difficulty removing the SOV because the piping was slightly misaligned. Consequently, mechanics utilized jacks and prybars to make the minor adjustment required to align the flanges and reinstall the fasteners. Throughout the job, the inspectors observed that the mechanics appeared to be rushed to the extent they could have been vulnerable to more errors. The foreman took no action to coach them on safer, more deliberate work performance.

After the job was completed, the inspectors examined the new SOV installation and found one flange nut approximately half engaged. Upon questioning the maintenance foreman, he was not aware of the condition. This condition should have been identified by the mechanics when they applied torque to the nut. This degraded condition, although previously evaluated by engineering as acceptable, might have been corrected during this maintenance activity.

The licensee shipped the failed SOV to an independent facility to perform a detailed failure analysis. This activity was still in progress as of the end of this inspection period. The inspectors were informed of preliminary results; however, indicating that the upper and lower operating cylinders for the SOV were not concentric. This apparently caused the valve disk and piston assembly to operate misaligned, and it finally failed to unseat when called to operate on August 16. Because the eccentricity may be attributed to the manufacturing process, the inspectors questioned the generic implications, and as such will follow up on the final failure analysis results. This shall be tracked under an Inspection Followup Item (458/9523-03).

4.5 MWO P585136 Division III DG

On August 23, 1995, the inspectors observed the conduct of insulation resistance testing on the Division III DG in accordance with General Maintenance Procedure GMP-0019, "Insulation Resistance Testing (Meggering)." These tests were performed as a periodic check of the DG following an event which occurred in December 1994, during which the DG was paralleled to the grid out of phase. The inspectors noted good use of electrical safety equipment while the electricians installed a grounding device into the high voltage (4160 volt) breaker cubicle for this work. In addition, the inspectors noted that the work instructions provided for independent verification of lifted leads and removal of installed jumpers.

During this maintenance, the electricians found debris in the bottom of the HPCS DG output breaker cubicle. System Engineering was contacted for an evaluation of the condition. Further inspection revealed that small pieces of cement material, which held the "C" phase ceramic bus stab insulator in place, had chipped off. CR 95-0846 was initiated and an operability determination was provided. After discussions with the equipment vendor, the system engineers determined that the deficiency did not adversely affect the operation of the breaker and did not pose an electrical safety concern. The inspectors reviewed the operability determination and found it to be acceptable. The inspectors considered the identification of the deficiency, which could have easily been overlooked, demonstrated good attention to detail.

5 SURVEILLANCE OBSERVATIONS (61726)

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

Procedure Number	Title
STP-255-4520	PVLCS Air Accumulator Tank 6B Air Pressure Instrumentation.
STP-204-6302	Residual Heat Removal (RHR) Pump B and Associated Valve Quarterly Inservice Test.

The inspectors found no significant strengths or weaknesses during the observations, except as noted below:

5.1 STP-255-4520 PVLCS Air Pressure Instrument Test

On August 4, 1995, the inspectors witnessed maintenance technicians performing Surveillance Test Procedure STP-255-4520, "PVLCS-Air Accumulator Tank 6B Air Pressure Instrumentation, Monthly Channel Functional," Revision 1. The inspectors verified that the procedure satisfied the intended TS surveillance requirements.

The inspectors verified that Operations signed the procedure allowing it to be performed, and that all test instrument calibrations were current. During this surveillance, the maintenance technicians demonstrated good procedural compliance and good communications with the operators. Also, the maintenance technicians followed the licensee's STAR program (stop, think, act, and review) prior to installing test instruments and manipulating switches.

5.2 STP-204-6302 RHR Pump B Inservice Test

On August 28, 1995, the inspectors observed the inservice testing of RHR Pump B and associated valves as delineated in Procedure STP-204-6302, "Div II LPCI (RHR) Pump and Valve Operability Test," Revision 8B. The personnel assigned to accomplish the test were well familiarized with the STP contents. Minor delays were experienced in obtaining the correct test equipment; however, once obtained, the equipment was in good condition and in current calibration. Test personnel used good radiological work practices in connecting the equipment. The test was conducted in a step-by-step manner in accordance with the STP, and good, crisp communications were used. After test completion, the inspectors reviewed the completed data and found it to be legible and well within the acceptance criteria.

Overall, this surveillance activity was performed well.

6 ONSITE ENGINEERING (37551)

6.1 Inadequacy of Hydrogen Igniter Surveillance Test Procedure

On August 10, 1995, a Procedure Upgrade Project reviewer identified a problem where Procedure STP-254-1402, "Semi-Annual Hydrogen Igniter Train Current and Voltage Check," Revision 5, may not have been adequate to detect inoperable, individual hydrogen igniters as required by TS 4.6.6.3.a. The potential of a plant shutdown in 24 hours existed as required by TS 4.0.3. CR 95-0798 was initiated.

Later, on August 10, the licensee's operability assessment declared the hydrogen igniters operable on the basis of Licensing Memorandum 5-CRB-17270, which resolved the same question that arose on October 17, 1991, on CR 91-0452. The memorandum stated that a functional test was not expected to test every aspect of the system, and that the STP provided "reasonable assurance" of operability. The inspectors questioned the licensee's position; however, it appeared that if analyzed, the data obtained by the STP might have provided the information required by TS 4.6.6.3.a.

The inspectors requested copies of the data obtained every 6 months since the 1994 refueling outage, including the 18-month test of individual igniters, Procedure STP-254-1600, "Hydrogen Igniter 18 Month Current/Voltage and Temperature Check." All data was provided by the licensee except the 18-month STP. As of the end of this inspection period, the licensee was unable to retrieve the 18-month data; however, the completion certification sheet was found, indicating that the test was completed. On August 18, the licensee initiated CR 95-0835 documenting the record retrieval problem. The licensee conducted an extensive search and did not find the 18-month data.

Also, an expanded investigation was implemented to ensure the records storage and retrieval process did not have flaws, and it did not. An additional sampling of other STP data was successfully retrieved, indicating this to be an isolated case. The failure to retrieve safety-related surveillance data records is a violation of TS 6.10.2.d. However, in view of the ability of the licensee to certify completion of the STP, and the extensive corrective action taken, this failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

While analyzing the STP data requested, the inspectors identified two problems:

- The data in Procedure STP-254-1402 obtained since the 1994 refueling outage appeared to indicate one failed igniter in Division I Circuit 8, based on the as-found current. This led to the licensee determining that the STP called out a duplicate Igniter 33A, in error. After correcting the error, all igniters appeared to be operable.

- The data in Procedure STP-254-1402 completed on November 29, 1994, indicated that the electri ans recorded Division II Panel B1 data in the Panel B2 blanks and vice versa. The licensee corrected this by issuing a record revision notice on September 8. The inspectors reviewed the notice and found that it corrected the error.

The licensee performed concurrent reviews and concluded that, even though Procedure STP-254-1402 was not adequate to immediately identify single inoperable igniters, sufficient data was obtained to verify operability through analysis, as required by TS 4.6.6.3.a. The inspectors came to the same conclusion. The licensee stated that the STP would be revised to immediately identify a failed igniter in time for the next date of performance. Failure to maintain an adequate STP is a violation of TS 6.8.1.d; however, this licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy.

The procedure upgrade project reviewer demonstrated good attention to detail in identifying the inadequacy of Procedure STP-254-1402, and engineering acted appropriately by analyzing the data to confirm operability of the individual hydrogen igniter.

7 PLANT SUPPORT ACTIVITIES (71750)

7.1 Security Observations

During a tour of the plant on August 1, 1995, the inspectors noted a vital security door to the Division II DG room was left open. The door was opened to provide additional ventilation to the DG room due to ongoing painting. The inspectors confirmed that a security officer was posted outside the door controlling access and that the DG room was listed on the hourly firewatch rounds.

During construction activities related to the new engineering building, the inspectors observed that the security force was very attentive in maintaining protected area boundary and exclusion area integrity.

7.2 RP Activities

On August 9, 1995, the licensee identified an incident where an RP technician on routine building rounds found two radiation area postings moved by an unknown person without RP permission. CR 95-0797 was initiated. The postings were originally placed in the offgas sample panel room to alert workers of a 12 mR/hr field, but were found outside the room. RP immediately restored the posting and issued an RP notice to all employees reminding them that RP postings of any type must not be moved. The RP Notice was distributed and posted in several ways, and could not credibly be missed by anyone who entered the Protected Area.

Subsequent investigation revealed that painters had been working in the offgas building for approximately 4 weeks; however, the individuals who moved the postings could not be identified. Plant Modification and Construction management assumed responsibility for corrective action. In the past, the painters were granted permission to move certain postings, when it was appropriate to do so. This practice was terminated by RP management. RP access control records were reviewed and the highest individual exposure was 2 mR, which was not unexpected for working in the room.

The inspectors followed up on this issue to evaluate the licensee's corrective actions on this issue and found that a thorough and comprehensive approach was taken. All actions were appropriately documented, including training of all Plant Modification and Construction personnel, which included the painters.

7.3 Emergency Preparedness

During this inspection period, the inspectors toured the Technical Support Center and Emergency Operations Facility with licensee personnel. The facilities were found to be ready for emergency use and in satisfactory condition. The inspectors noted that the licensee utilized wall charts for displaying key plant status information to emergency response personnel. Since a time delay (5-10 minutes) could exist in updating this information, the inspectors expressed a minor concern that with the installation of the Emergency Response Data System, NRC response personnel may obtain updated important plant status information before onsite licensee response personnel. The licensee stated that long-term improvements were planned to upgrade the display of this type of information.

8 FOLLOWUP OF CORRECTIVE ACTIONS FOR VIOLATIONS (92903, 92904)

8.1 (Closed) Violation 458/9422-05: Inadequate Procedure Resulted in Plant Operation in a Condition Prohibited by TS

During a review of CRs generated by the licensee following the September 8, 1994, reactor scram, the inspectors noted CR 94-1263, dated October 3, 1994, where the licensee identified a condition in 1992 and again in early 1994 where the time response of reactor pressure vessel Level Transmitters 1B21*LTN080C and -D did not meet the TS 3.3.1 minimum of 1.05 seconds. This resulted in operation of the plant in a condition prohibited by TS.

The primary root cause was that there were no acceptance criteria in Plant Engineering Procedure PEP-0053, "Sensor Response Time Testing Using Process Noise," Revision 0. Also, the procedure did not provide guidance on the various responsibilities required for procedure implementation. A contributing factor was that after the results were transmitted to instrumentation and control personnel they were not utilized until the associated STP was performed. This resulted in a delay for comparison of acceptance criteria to time response data. Finally, the fact that station personnel had two separate chances to identify and correct the noncompliance contributed to the fact that the plant was operated with less than the minimum operable channels per trip system and, therefore, was in a condition prohibited by the TSs.

The inspectors reviewed the documentation of completed corrective actions. System Engineering completed a historical review of all Procedure PEP-0053 data and found no other discrepancies. Based on a review of training records, the inspectors found that appropriate performance feedback and counseling was provided to all of the instrumentation and control department technicians and the system engineers involved in the event.

All plant engineering procedures were reviewed by the licensee to identify problems with acceptance criteria similar to those of Procedure PEP-0053. No procedures needed to be revised.

Procedure PEP-0053 was revised on March 31, 1995, to specify acceptance criteria and clearly assign responsibility for review of the test data. The revised procedure required a review of the most previous performance of each applicable STP and compare the results to ensure that the acceptance criteria specified in the STP were met. This approach was acceptable.

8.2 (Closed) Violation 458/9502-01: Failure to Maintain Six Emergency Lights Operable

In January 1995, the batteries for six emergency lights required by 10 CFR 50, Appendix R, were found fully discharged and, therefore, incapable of providing illumination in an emergency. While the licensee performed the root cause investigation, they discovered that, of the 284 emergency lights required for a safe shutdown of the plant, 128 emergency lights did not have monthly PM MWOs. When the licensee issued the MWOs and performed the PMs, four additional emergency lights failed to illuminate as required. In addition, there were 12 units located in locked high-radiation areas which could not be checked until the next plant shutdown.

The inspectors performed a walkdown of the six emergency lights and determined that the batteries were being charged as required. The inspectors verified that these six emergency lights plus twenty more randomly selected had PM MWOs and were scheduled on a monthly basis.

As corrective action to prevent recurring problems in the PM Program, the licensee implemented a comprehensive initiative on the upgrade of PMs, outlined in Section 10 of the River Bend Long-Term Performance Improvement Plan, as described in the licensee's response to this notice of violation. The inspectors interviewed plant staff responsible for the PM Upgrade Project, reviewed schedule performance documentation, and found that the project was on schedule for completion by the end of 1996.

9 IN-OFFICE REVIEW OF LERs (90712)

The following LERs were reviewed by the inspectors and were determined to have met the reporting requirement of 10 CFR 50.73, the reports contained adequate assessments of the subject events, the causes were accurately identified, corrective actions were appropriate to the circumstances, the generic applicability was properly considered, and no further regulatory followup was indicated.

9.1 (Closed) LER 458/94-031: Failure to Identify TS Noncompliance Due to Inadequate Test Procedure

This event was addressed in NRC Inspection Report 50-458/94-22, Section 9.2. A violation was identified, corrective actions completed, and the violation was closed in Section 8.1 above.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

R. J. Alexander, Acting Director, Plant Projects & Support
W. R. Brian, Manager, Strategic Planning
E. C. Ewing, Manager, Maintenance
J. J. Fisicaro, Director, Nuclear Safety
W. C. Hardy, Supervisor, Radiation Control
J. Holmes, Superintendent, Chemistry
H. B. Hutchens, Superintendent, Plant Security
T. P. Lacy, Outage Coordinator
T. R. Leonard, Director, Engineering
D. N. Lorfing, Supervisor, Licensing
J. R. McGaha, Vice President-Operations
J. M. McGhee, Operations Technical Assistant
D. E. Metcalf, Manager, Training
M. B. Sellman, General Manager, Plant Operations
R. G. West, Acting 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 September 8, 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 did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

List of Acronyms

CR	condition report
DG	diesel generator
HPCS	high-pressure core spray
LER	licensee event report
MWO	maintenance work order
NRR	Office of Nuclear Reactor Regulation
PM	preventive maintenance
PVLCS	penetration valve leakage control system
RHR	residual heat removal
RP	radiation protection
RWCU	reactor water cleanup
SERT	significant event review team
SOV	solenoid operated valve
SSW	standby service water
STP	surveillance test procedure
TS	Technical Specification