APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/93-27

Operating License: NPF-47

Licensee: Gulf States Utilities
P.O. Box 220
St. Francisville, Louisiana 70775-0220

Facility Name: River Bend Station

Inspection At: St. Francisville, Louisiana

Inspection Conducted: September 26 through November 6, 1993

Inspectors: W. F. Smith, Senior Resident Inspector
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Approved: for J. E. Gagliardo, Chief, Project Section C   12/17/93 Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite response to events, operational safety verification, containment leak rate test results evaluation, maintenance and surveillance observations, followup, and review of licensee event reports (LERs).

Results:

- During the performance of surveillance testing, the licensee experienced a third inadvertent reactor core isolation cooling (RCIC) isolation in the past year. The licensee's corrective actions in response to the isolation was appropriate to the circumstances and indicative of the new management's apparent resolve to implement thorough and complete root cause evaluations and corrective actions (Section 2.1).

- The plant experienced two loss of feedwater heater events on October 13 and 14. Though the first loss was caused by a relay failure, the second loss could have been avoided by adequate self-checking and by supplying the electricians with more suitable tools. The operators responded well to both events, and the licensee's corrective actions to address this issue were good (Section 2.2).

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- The licensee identified that the turbine trip of October 14, resulting in a reactor scram and the plant transients associated with the scram, should have been prevented by actions in response to LER 458/89-003. A turbine trip bypass switch was not used during testing as committed in LER 458/89-003, and the licensee did not correct deficiencies discovered in the switch circuit. The licensee's subsequent corrective actions and plans to review LER commitment tracking were appropriate (Section 2.3).

- The alertness and questioning attitude of the operator in challenging the proper operation of Local Power Range Monitor 46-39B was excellent. This resulted in the discovery of the mispositioned calibration switch. However, a potential violation may exist which caused the switch to be incorrectly positioned. An unresolved item was identified pending the licensee's further review to determine the cause of the mispositioned switch (Section 2.4).

- Control room operations have continued to show steady improvement, as demonstrated by an event-free, carefully controlled, startup evolution conducted October 18-21, 1993. Relocating the Control Operating Foreman into the "at-the-controls" area appears to have improved the quality of senior reactor operator oversight (Section 3.1).

- Housekeeping practices within the plant were mixed. Areas which had received significant management attention such as the reactor plant closed cooling water (RPCCW) area and Division III diesel generator (DG) rooms were well maintained. However, plant personnel did not demonstrate the same housekeeping practices in areas which had not been improved and in some contaminated areas (Section 3.2).

- Based on an assessment of licensee controls over switchyard activities prompted by various industry events, the inspectors found that the licensee had implemented good controls at River Bend Station to prevent undesirable transients and safety system challenges that could be caused by switchyard events (Section 3.3).

- Based on the review of the containment integrated leak rate test results, the inspectors concluded that the test was satisfactorily completed as required by NRC regulations (Section 4.1).

- The RCIC troubleshooting activity was not well coordinated. The licensee had not developed a comprehensive troubleshooting plan to minimize the number of times the short-term Technical Specification action statement was entered. Operations had not required that a comprehensive troubleshooting plan be developed until late in the work activity, when coordination problems surfaced (Section 5.1).

- Failure to provide an adequately reviewed, technically correct work instruction to prevent a turbine trip and/or runback demonstrated a weakness in the licensee's maintenance work order (MWO) process. This was mitigated by the questioning attitude of the instrumentation and controls (I&C) technicians and the willingness of the I&C foreman to stop the job and make sure all questions were addressed before proceeding (Section 5.2).

- Verification of untested control circuits in the annulus mixing system was well planned, well executed, and satisfied the overlap deficiency identified during logic system functional surveillance test procedure reviews (Section 5.4).

- A violation was identified for failure to specify a postmaintenance test following the adjustment of the instantaneous overcurrent trip setting on the breaker supplying power to safety-related motor-operated Valve 1E12*F006B (Section 5.5).

- Inadequate work instructions for the trip unit replacement resulted in an unnecessary delay in returning the RCIC system to operation. However, the surveillance test was conducted in accordance with the procedure requirements. Good self-checking techniques were utilized. Communications between the operators and the I&C technicians were appropriate to ensure that the short-term action statement time limitation was reviewed and expected control room annunciators were identified prior to being received (Section 6.1).

- One example of a violation was identified for failure to follow the Division III DG operability surveillance test procedure sequence as required by station administrative procedures. This demonstrated that not all operators had achieved the level of procedure compliance expected by plant management (Section 6.2).

- Pressure regulation system testing and dynamic response verification accomplished on October 2 by the coordinated efforts of System Engineering, Reactor Engineering, and Operations was performed in an excellent manner (Section 6.3).

- A second example of a violation was identified for failure to follow procedures during an unsuccessful attempt to conduct inservice testing of the Division II low pressure core injection pumps. In addition, a repeat violation was identified for failure to provide an adequate procedure for that purpose. Corrective actions taken by the licensee appeared to not be fully effective. After the procedure was corrected and revalidated, the test was performed satisfactorily (Section 6.4).

Summary of Inspection Findings:

- Unresolved Item 458/93027-1 was opened (Section 2.4).
- Violation 458/93027-2 was opened (Section 5.5).
- Violation 458/93027-3 was opened (Sections 6.2 and 6.4).
- Violation 458/93027-4 was opened (Section 6.3).
- Unresolved Item 458/93003-2 was closed (Section 7.1).
- LERs 458/93-007 and 458/93-013 were closed (Section 8).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the plant was operating at full power.

On October 12, 1993, power was reduced to about 85 percent in response to the loss of both first string feedwater heaters caused by a failed relay (paragraph 2.2). After the heaters had been restored on October 14, power was in the process of being increased at a slow rate (1 percent per hour), when a turbine trip occurred during routine testing, resulting in a reactor scram (paragraph 2.3).

On October 18, a reactor startup was initiated from a hot shutdown condition (Mode 3), and full power operation was resumed by October 21. On October 30, power was reduced to 75 percent to repair a leaking main condenser tube. On October 31, power was restored to 100 percent.

As of the end of this inspection period, the plant continued to operate at full power.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Inadvertent Isolation of Reactor Core Isolation Cooling (RCIC)

On September 24, 1993, while performing Surveillance Test Procedure STP-207-5255, "RCIC/RHR System Isolation, RHR Equipment Area Ambient Temperature High Monthly Channel Functional, 18 Month Channel Calibration, 18 Month LSFT (E310-N608B)," Revision 5, a Division II RCIC isolation occurred, closing RCIC steam supply Valve E51*MOVF063. At the time, the plant was operating at full power, therefore, the RCIC system was required to be operable.

The shift supervisor declared the system inoperable until the cause of the actuation could be determined and corrected. The operators entered the action statement for Technical Specification 3.7.3, which allowed continued plant operation for up to 14 days provided high pressure core spray was operable.

The licensee's investigation could not conclusively determine the cause of the isolation, since the isolation could not be recreated. However, a malfunction of the temperature switch was highly suspect. The I&C technicians stated that, during the performance of the procedure, they noted chattering and buzzing coming from a relay and the temperature switch. After the isolation, the technicians did not alter or remove any of the test equipment or setup until after the foreman had verified everything was properly connected, or that leads had been lifted as required. During testing, there were several times when a series of voltage spikes occurred; however, the isolation signal could not be repeated. The licensee determined that it was possible for voltage spikes of sufficient magnitude, frequency, and duration to be generated under the right circumstances and cause the isolation to occur.

The corrective actions taken, or to be taken, by the licensee were: (1) replace the temperature switch and two relays; (2) revise the monthly channel functional section of all surveillance test procedures (STPs) that test a temperature switch which has input to this circuit, to require the technician to lift additional leads to electrically isolate any induced voltage; (3) place a switch in the circuit which will isolate the relay instead of having to lift leads; and (4) place a step in each STP to take voltage readings prior to determining continuity when verifying closed or open contacts in this circuit. The new step is to include a note to contact System Engineering if voltages greater than 25 volts exist.

On December 30, 1992, and August 13, 1993, similar actuations occurred. The first actuation occurred on Division I during conduct of the RCIC isolation test for the residual heat removal (RHR) equipment area high ambient temperature. The licensee's investigation identified several possible causes but the actual component that failed was not identified. However, as corrective action, two similar temperature switches and a relay were replaced as the most likely failure mechanisms. The second actuation occurred on Division II during the performance of the RCIC isolation test for the RCIC equipment area high ambient temperatures. The licensee's investigation did not determine a cause but, through analysis of the event, it was determined that a momentary failure of the RCIC isolation bypass switch was the most likely cause. The switch was replaced. LERs 458/92-029 and 458/93-018 provide additional details, but the root causes of the isolations were not firmly established.

As part of the initiative to firmly establish the causes of the previous isolations, the licensee had implemented a plan to instrument suspected parts of the isolation circuitry to allowed identifying the causes of an isolation if it were to occur. The plan did not include Procedure STP-207-5255, so when the isolation occurred on September 24, the licensee did not capture any additional information to assist in identifying the exact root cause. The plan did not include Procedure STP-207-5255 because the previous isolations occurred during the performance of other procedures.

After the September 24 isolation, the licensee expanded the scope of corrective actions by including all STPs associated with RCIC isolations to require instrumentation of circuits, lifting additional leads, and initiating a Modification Request to install a key-locked switch to replace the lifting of leads. LER 458/93-022 provides additional details. The inspectors concluded the licensee's actions after the September 24 isolation were appropriate.

2.2 Loss of Feedwater Heater

On October 12, 1993, while the plant was operating at 100 percent power, feedwater heater control Relay 71WB-1HDHB01 overheated and failed. This failed relay caused an isolation signal for Feedwater Heater String B, causing a momentary reactor power spike to 103 percent. The operators responded to the loss of the feedwater heater by entering Abnormal Operating Procedure AOP-0007, "Loss of Feedwater Heating," Revision 7. This procedure directed the operators to reduce power, as a function of the feedwater temperature decrease. Reactor power was stabilized at 94 percent with the average feedwater temperature at 395°F. This temperature was approximately 20 degrees below the temperature normally seen at the 94 percent power level.

The isolation signal caused the reheater drain receiver tank control valve (DSR-LV65B) and the scavenger steam valve to the condenser (DSR-MOV110) to close and the high level dump valve (DSR-LV68B) on the reheater drain receiver tank to open.

The licensee's initial corrective actions consisted of writing two condition reports. One was to identify the failed relay and issue MWO R059553 to replace the relay. The second condition report was issued to track the effect of the cooler feedwater temperature on the reactor feedwater nozzles in terms of exposure to thermal stress, as required by Procedure AOP-0007.

On October 13, an electrician was installing a jumper around the power supply for the failed relay to facilitate the installation of a new relay without losing power to the other relays. The jumper was landed on the wrong termination point, causing a loss of feedwater heating to the remaining first point heater. The operators promptly entered Procedure AOP-0007 and lowered reactor power to approximately 85 percent. All valves responded normally to the isolation signal. No reactor power spike was detected, because the operators were aware of the work in progress and of the potential risk of losing an additional heater.

To determine the root cause of the second isolation, the licensee utilized the Human Performance Enhancement System. The root cause determination revealed that the electrician failed to self-check and to take adequate precautions to avoid contact with nearby voltage sources. While responding to the second loss of feedwater heater event, the inspectors questioned the electrical foreman who had been present and found that the electricians were using a hook-type "mini-grabber" to establish the jumper connections. This device was required for use in control room panels by a 1989 maintenance management memorandum, because of the inherent risks of using alligator clips in critical panels. However, the hook also appeared likely to slip off. When it slipped off this time, the electrician was not sufficiently careful to avoid inappropriate contact with other terminals. Use of the hook-type "mini-grabber" was considered a contributing cause of the event.

The corrective actions that the licensee implemented based on the identified root causes consisted of: (1) conducting training for both I&C and Electrical Department personnel on this incident and to emphasize the need for self-checking; (2) evaluating the use of additional barriers, such as MWO instructions, training, and field observations/work practices; (3) analyzing the current rules to determine if they were too limiting and prevent the use of proper tools for a job; and (4) consider the use of other connectors which are available and may be more suitable to the different types of connections that are required to be made. The inspectors concluded that these actions were appropriate.

2.3 Reactor Scram Caused by Turbine Trip

On October 14, 1993, while the plant was operating at 95 percent power, a main turbine trip occurred, resulting in a reactor scram. The scram signal originated from the turbine control valve fast closure logic. The inspectors responded by entering the control room immediately after the scram. The inspectors noted that the operators had entered and complied with the appropriate abnormal and emergency operating procedures as they stabilized plant shutdown conditions. The safety-related systems responded as designed. Four steam relief valves lifted and reseated properly. The operators worked well as a team in dealing with the complexities of the rapid shutdown, but were briefly distracted over concerns about two feedwater pump suction relief valves that had lifted because the condensate miniflow Valve CNM-AOV114 had been isolated from service. This valve was removed from service because of seat leakage and concern about possible erosion.

The inspectors were concerned about this distraction and verified that the licensee was taking action to resolve and correct the condition. Subsequently, with engineering support, the licensee determined that there was sufficient flow through the condensate pumps to allow the operators sufficient time to stabilize reactor plant parameters before establishing long cycle condensate recirculation. This was covered in special simulator training prior to startup. This action appeared to be a safe alternative to the major work that would be required to repair Valve CNM-AOV114.

The inspectors reviewed the scram recovery and posttrip review data, as delineated in General Operating Procedure GOP-0003, "Scram Recovery," Revision 8. The data confirmed that the reactor protection system trip signal came from fast closure of the turbine control valves. Due to shrink in the reactor (steam bubbles collapsed from a combination of power decrease from the scram and pressurization from fast closure of the turbine control valves), reactor vessel low level (Level 3) was reached, causing an actuation signal from Groups 5, 14, and 17 containment isolations. No valves operated, however, because the affected systems were not in use at the time. The applicable valves were already closed, which was a normal configuration.

Maximum reactor pressure vessel pressure during this event was 1114 psig and minimum pressure was 938.7 psig. Prior to the event, pressure was 1012.7 psig. The scram recovery and posttrip review package contained all of the pertinent data relative to the scram and addressed all of the startup issues and their resolution. This package was considerably more comprehensive than past packages.

The licensee established a "Significant Event Response Team," which worked around the clock to establish the root cause and associated corrective actions for the scram and to disposition the plant transient data.

When the turbine tripped, the operators had just completed routine weekly turbine valve tests and were conducting the upper thrust bearing wear detector test in accordance with Operations Section Procedure OSP-0101, "Turbine Generator Periodic Testing," Section 4.9, Revision 6. The detector was tested by depressing the "Upper Test Switch," which energized a K11 relay, which in turn energized a K15 relay that was designed to open the turbine trip bus circuit to prevent a turbine trip while testing the thrust bearing wear detector. Apparently these relays did not function properly at the time of the test. The licensee made several attempts to duplicate the condition, but was unsuccessful.

The licensee identified that a similar event occurred on February 25, 1989, and was reported to the NRC in LER 458/89-003. Modification Request (MR) 89-0046 was implemented to install a trip bypass switch on control room Panel 1H13-P821 for use during weekly testing. Procedure OSP-0101, however, did not require its use and it only partially blocked the turbine trip signals.

In a detailed assessment of the electrohydraulic control system conducted by the Nuclear Safety Assessment Group SA 91-002, dated October 20, 1992, a concern was identified that the bypass switch, when needed, would bypass turbine trip signals, but would not bypass the "close valves" signal to shut down the main turbine, resulting in an anticipatory reactor scram when testing at high power. The report recommended the bypass switch circuit be corrected to perform as originally intended or to discontinue its use.

In Memorandum APMS-93-039, dated March 4, 1993, from System Engineering to Operations, it was recommended that the use of the switch be discontinued as action to close out the Nuclear Safety Assessment Group recommendation. No reference was made to consider correcting the circuit, nor was the commitment in the LER mentioned.

On March 30, 1993, Procedure OSP-0101, Revision 5A, was revised by Change Notice 93-0192 to remove the requirement to utilize the turbine trip bypass switch during turbine testing.

After the September 24, 1993, scram, MR 89-0046 was corrected and properly implemented as originally intended. The K15 relay was replaced; however, during the retest it failed to function properly to provide the appropriate annunciation. The relay was replaced again, and the MR was satisfactorily retested.

The inspectors questioned how many other MRs were not functioning as intended. This was the third instance recently documented in NRC inspection reports for which there were inadequacies related to MRs. The first was relative to containment airlock door interlocks (NRC Inspection Report 50-458/93-11), and the second was related to a liquid radioactive waste discharge piping modification (NRC Inspection Report 50-458/93-26). The licensee stated that they had already initiated a comprehensive search to address this question. The inspectors also questioned the adequacy of licensee barriers to prevent the inadvertent cancellation of commitments made to the NRC, such as through LERs. The licensee stated that they would be addressing that question also. The inspectors concluded that the licensee's subsequent corrective actions and plans to review LER commitment tracking were appropriate.

2.4 Local Power Range Monitor (LPRM) Found Inoperable During Startup

On October 19, 1993, during the startup that followed the October 14 scram, the operators found the Bypass/Calibrate/Operate switch on LPRM 46-39B in the "calibrate" position, when it should have been in the "operate" position.

After shifting reactor recirculation pumps to fast speed, the reactor operator noticed from his display that the LPRM adjacent to a control rod he had selected was indicating down scale. He expected, after the power increase, that the LPRM would reflect an increase in power level. The operator placed the affected Average Power Range Monitor (APRM) D in bypass, thus considering the APRM inoperable until the question was resolved.

The shift technical advisor and reactor engineer examined Panel H13-P672 in the control room and found the switch on LPRM 46-39B to be in the incorrect position. The reactor engineer performed Reactor Engineering Procedure REP-0037, "LPRM Operability," Revision 2A. The switch in LPRM 46-39B was repositioned to "operate," and no other LPRM switches were found out of position. APRM D was returned to an operable status, and the startup was resumed.

The inspectors questioned whether this was another example of a weakness in the licensee's independent verification program. NRC Inspection Report 45-458/93-20 contains a notice of violation that addresses this problem. The licensee provided the inspectors with a copy of the last completed APRM weekly Procedure STP-505-4504, performed on APRM D on October 15, 1993. The document showed that this particular switch on all LPRMs was required to be in "operate," and all of the switches were independently verified to be in "operate" upon completion of the test procedure. Action Step 7.1.16 restored the switch to the "operate" position, and Restoration Step 1 on Attachment 4 of the procedure independently verified restoration again.

As of the end of this inspection period, the licensee had not yet completed the investigation of all of the possible causes of the LPRM switch being out of position. A potential violation appeared to exist; however, the nature of the violation was indeterminate. The licensee's corrective actions to correct weaknesses in their independent verification program were scheduled for completion by November 30, 1993, as stated in their reply to Notice of Violation 458/93020-2, dated September 16, 1993, and they had not yet been implemented at the time the LPRM switch was found out of the correct position.

This is an unresolved item (458/93027-1) pending completion of the licensee's investigation.

2.5 Conclusions

The licensee's corrective actions in response to the third inadvertent RCIC isolation was appropriate to the circumstances and indicative of the new management's apparent resolve to implement thorough and complete root cause evaluations and corrective actions.

The operators responded well to both losses of feedwater heating that occurred on October 13 and 14. Though the first loss was caused by a relay failure, the second loss could have been avoided by self-checking and supplying the electricians with more suitable tools. The licensee's corrective actions to address this issue were good.

The licensee identified that the turbine trip of October 14, resulting in a reactor scram and the plant transients associated with the scram, should have been prevented by actions in response to LER 458/89-003. A turbine trip bypass switch was not used during testing as committed in LER 458/89-003, and the licensee did not correct deficiencies discovered in the switch circuit. The licensee's subsequent corrective actions and plans to review LER commitment tracking were appropriate.

The alertness and questioning attitude of the operator in challenging the proper operation of LPRM 46-39B was excellent. This resulted in the discovery of the mispositioned calibration switch. However, a potential violation may exist which caused the switch to be incorrectly positioned. An unresolved item was identified pending further review to determine the cause of the mispositioned calibration switch.

3 OPERATIONAL SAFETY VERIFICATION (71707, 93001)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with regulatory requirements and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation.

3.1 Control Room Observations

On October 18-21, 1993, the inspectors monitored startup activities in the control room on a periodic sampling basis. The startup was conducted from hot shutdown conditions in accordance with General Operating Procedure GOP-0001, "Plant Startup," Revision 11A. The inspectors noted good communications were being used between control room operators and other watchstanders. Instructions and information were repeated back to confirm understanding. Controls were in place to limit visitors from entering the "at-the-controls" area to minimize distractions. Procedures were followed and incoming annunciations were promptly attended to. Shift turnovers were conducted incrementally to limit the number of key watchstanders engaged in turnover discussions. The startup was accomplished in a slow, deliberate, and professional manner without incident.

During midnight shift and weekend tours of the control room, the inspectors noted that the operating crews were alert and attentive to the controls.

The inspectors observed other control room activities throughout the inspection period. Communications between the reactor operators and control operating foreman were good. The movement of the control room supervisor to a position inside the "at-the-controls" area provided for enhanced operations oversight. It was apparent that management's expectations for calling out of annunciators, along with other control room conduct, was routinely being reinforced. The operators were observed meeting these expectations on a more routine basis.

3.2 Plant Tours

The inspectors conducted inspection tours of the plant at various times during the inspection period. In general, housekeeping continued to improve in some areas of the plant as the licensee implemented management tours. Painting activities continued to progress on the 171-foot elevation of the Auxiliary Building. However, the inspectors identified the following discrepancies and notified the appropriate licensee representatives for correction:

- Several portable eyewash stations were staged in the services building where electricians pick them up whenever they work on electrical batteries. The inspector found one of these eyewash stations was discharged and not tagged out of service. The inspectors discussed the discharged eyewash station with maintenance management and the discharged eyewash station was removed. This was a minor industrial safety issue.

- A 6-inch long bolt was found in the reactor building, unsecured on the steps to the Reactor Water Cleanup (RWCU) heat exchangers, where it could have been kicked into the suppression pool. The bolt was removed.

- An electrical cable tray cover in the reactor building, identified as Cover 1TK503R, adjacent to Valve SWP*MOV4A, was covered with dirt and debris. It was subsequently cleaned.

- Behind Containment Unit Cooler B, there was a herculite barrier, poly bags containing used filters and other debris that had not been cleaned up in over 10 days. It appeared that the debris was from a recent filter replacement for the unit cooler. The area was promptly cleaned up.

- On Auxiliary Building Elevation 95 feet west, the inspectors noted a large containment integrated leakage test valve stored, but not secured, within about 3 inches of a low pressure core spray instrument tube. The impact on the seismic qualification of the tube was questioned. The licensee noted that an analysis already existed and that, although 3 inches was not a problem, 6 inches was the more conservative guideline. The valve was moved.

The inspectors also conducted periodic tours throughout the plant, with emphasis on radiologically controlled areas and on those buildings housing safety-related equipment. Areas which had received significant management attention, such as the RPCCW equipment area and Division III DG rooms, were well maintained. Personnel within these areas were observed to effectively control their tools and other work related materials. However, plant personnel did not demonstrate the same housekeeping practices in areas which had not been improved and in some contaminated areas. At times, the area outside the RWCU pump rooms was congested with contaminated materials around the step off pad. Tools were left throughout the contaminated area which would require appreciable radiological protection technician involvement to clean up.

It was noted that fire doors were properly positioned in the areas toured. However, the inspectors noted that a radiological posting sign had been placed in front of a normally open "do not block" fire door. This door was located outside the RWCU area and would not have closed if required. The shift supervisor was notified and the posting was promptly moved to an appropriate location.

The inspectors toured areas not required to be entered to complete the nonlicensed equipment operators' rounds. Several instances were noted where deficient equipment had not been identified or materials had been left for an extended period and not corrected. An example included service water Valve 1SWP-MOV74A packing. Each of these deficiencies was identified to licensee management and resolved or placed in the work tracking system.

The inspectors verified that valves within the accessible emergency core cooling system major flow paths were properly aligned. The inspectors walked down portions of those systems and verified that the valve lineups were in accordance with the operating procedures. Required auxiliary systems were found to be operable. The main control board indications were found to be consistent with the field conditions.

3.3 Licensee Controls Over Switchyard Activities

The inspectors assessed the adequacy of the licensee's current switchyard controls. The scope of the assessment was to determine if the licensee had implemented the following:

- An approved procedure that controls the access to, and activities within, the switchyard.

- Control over switchyard work that was under the plant's maintenance work order system.

- Nonplant personnel had received the same training on the procedure as plant personnel.

- Quality Assurance (QA) had performed audits/surveillances of switchyard activities.

The inspectors reviewed River Bend Nuclear Procedure RBNP-061, "Vehicular Traffic Control Plan," Revision 0, which provided a program for controlling vehicular traffic (in particular, large mobile cranes and service/support vehicles) in and around areas of the facility considered "sensitive." References to this procedure included NRC Information Notice 92-13, "Inadequate Control Over Vehicular Traffic at Nuclear Power Plant Sites," and NUREG 1410, "Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle Unit 1 on March 20, 1990." Additionally, Operations Policy 009, Revision 3, had been established to assure the availability of offsite power and preclude the receipt of isolation signals when performing work on the main generator output breakers. This guidance was established in light of the March 1990 loss of offsite power at Vogtle Unit 1 and other events which had occurred at River Bend Station.

The inspectors found that the work control process and access to switchyards were under the control of the Shift Supervisor/Control Operating Foreman and that nonplant personnel had been trained on the work control process.

The inspectors review of QA activities revealed a history of audits and surveillance activities in this area dating back to 1983. QA had also identified a recent industry operating experience item related to main transformers that they planned to incorporate into their next audit.

The inspectors concluded that the licensee had controls established that encompassed the scope of this assessment. During the course of this assessment, the inspectors interfaced with plant security, plant operations, plant maintenance, and nonplant personnel. All appeared to have a good understanding of their duties and responsibilities related to switchyard controls.

3.4 Followup on Missing Seismic Strap on Agastat Relays

On September 27, 1993, during routine review of licensee condition reports (CRs), the inspectors noted that CR 93-0587 had identified that Agastat Relay 1E31A*K4B was missing its seismic strap. This relay was located in the control room and was associated with the leakage detection system (high ambient temperature relay).

The inspectors followed up to determine what action the licensee had taken to verify the relay's operability with a missing seismic strap and to review the root cause determination and corrective action.

The relay was promptly replaced. The new relay had a seismic strap and, thus, was operable, alleviating any immediate operability concern.

The root cause was declared indeterminate; however, the licensee's investigation revealed possible contributing causes. There was a similar occurrence in 1992 (CR 92-0740), where a similar relay seismic strap was missing, and the cause was not determined.

As part of the investigation, the licensee conducted walkdown inspections of the 700 Agastat relays in both nuclear and balance-of-plant panels. Three other relays were found with a missing clip (one was a spare) and one had a clip in place, but it was not properly latched. The two safety-related relays were corrected as of the end of this inspection period, and the inspectors are following up to ensure completion of the other two relays.

The design engineering department performed an analysis which showed that, even though the seismic strap was part of the generic qualified design configuration for all seismic conditions, the relays at River Bend Station did not need the straps to withstand the design basis earthquake at this location. Rather than attempt a redesign, the licensee chose to maintain the generic design configuration.

The licensee had already taken action to prevent recurrence by changing maintenance procedures in April 1993 to direct attention to maintaining proper design configurations.

3.5 Conclusions

Control room operations have continued to show steady improvement, as demonstrated by an event-free, carefully controlled startup evolution conducted October 18-21, 1993. Relocating the Control Operating Foreman into the "at-the-controls" area appears to have improved the quality of senior reactor operator oversight.

Housekeeping practices within the plant were mixed. Areas which had received significant management attention, such as the RPCCW area and Division III DG rooms, were well maintained. However, plant personnel had not demonstrated the same good housekeeping practices in areas which had not been improved and in some contaminated areas.

Accessible emergency core cooling system major flow path valves were found to be properly aligned for operation of the plant at power (Mode 1).

Based on an assessment of licensee controls over switchyard activities prompted by various industry events, the inspectors found that the licensee had implemented good controls at River Bend Station to prevent undesirable transients and safety system challenges that could be caused by switchyard events.

The licensee's corrective actions to address a licensee-identified deficiency in maintaining the design seismic configuration of Agastat relays appeared to be sufficiently comprehensive.

4 CONTAINMENT LEAK RATE TEST RESULTS EVALUATION (70323)

The purpose of this portion of the inspection was to review the test results of the licensee's containment integrated leak test.

4.1 Discussion

The containment integrated leak rate was performed on August 14, 1992. The inspection of test performance was documented in NRC Inspection Report 50-458/92-27, dated September 21, 1992. The test was a short duration test performed in accordance with ANSI N45.4-1972, ANSI/ANS-56.8-1987, and BN-TOP-1, Revision 1. The test duration was 6 hours and consisted of 25 data sets. The test acceptance criterion was that the leak rate shall not exceed .75 La (0.26 percent per day) at a pressure of not less than Pa (7.6 psig). The actual test results were 0.169 percent per day with a 95 percent upper confidence limit.

The final test document was reviewed and no discrepancies were identified. As required by Appendix J to Title 10 of the Code of Federal Regulations, the licensee was required to report the results of the Types B and C testing performed. The licensee reported that the total "as-found" leakage for the Types B and C leak tests exceeded the specified limit of 0.6 La. The licensee performed repairs on the individual valves that had high leakage. The retests showed that the combined leakage was well within the specified limits.

The inspectors verified several test data points and found no errors.

4.2 Conclusions

Based on the review of the containment integrated leak rate test results, the inspectors concluded that the test was satisfactorily completed as required by NRC regulations.

5 MONTHLY MAINTENANCE OBSERVATIONS (62703)

The station maintenance activities addressed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with the licensee's approved maintenance programs, the Technical Specifications, and NRC Regulations.

5.1 RCIC Isolation Troubleshooting

The inspectors observed the performance of MWO R179137 on September 27, 1993, to troubleshoot and repair the RCIC isolation which occurred on September 24, 1993. The inspectors discussed the scope of the troubleshooting activity with the I&C technicians and the system engineer. It was identified that the troubleshooting activity had been in progress on an intermittent basis for several days. It was believed that a faulty relay (1E31A*K4B) had caused the Division II RCIC system isolation.

The inspectors noted that the troubleshooting activity had not been well defined. The licensee had entered into a 2-hour Technical Specification (TS) action statement by placing the associated Division II trip unit (1E31A*N608B) in bypass. During this period it was apparent that the I&C technicians and the system engineer had not established a comprehensive troubleshooting plan to maximize the activities that could be accomplished. In addition, the inspector noted that an individual with lead responsibility for the troubleshooting activity had not been established. This contributed to delays in conducting the trouble shooting activity when the trip unit was in bypass. During the conduct of the activity the inspector questioned the I&C technician when the 2-hour TS action statement had been entered. He subsequently referred to the surveillance procedure which had been included in the troubleshooting instructions and identified that it had been approximately 1 hour and 40 minutes. Because of the time required to restore the system prior to the 2-hour TS action statement expiring he decided to remove his test equipment to permit operations to take the trip unit out of bypass. After the system was restored the inspectors noted that the I&C technicians requested that the operators place the unit back into bypass so they could continue with the troubleshooting activity.

The shift supervisor subsequently questioned the individuals about the troubleshooting activities they were conducting. He identified that the trip unit would not be placed in bypass until a comprehensive troubleshooting plan had been developed. The inspectors noted that the shift supervisor's emphasis was on ensuring that the intent of the 2-hour TS action statement to permit short term testing without placing the channel in trip was met. The trip unit was placed in bypass one additional time to complete the troubleshooting activity. Subsequent management oversight was provided to ensure that the work activity was properly coordinated and job responsibilities were appropriately established.

The inspectors noted that the work control desk had recently been moved out of the control room to a room in the administration building. This troubleshooting work activity had been signed in at the remote work control desk and with permission to start granted by the shift supervisor. It was noted that responsibility for ensuring the 2-hour TS action statement was not exceeded was with the I&C technicians. Previously, the shift supervisor had maintained a log in the control room to specifically track when surveillances and work activities were started. This also provided a means of tracking this type of short term LCO. However, with the responsibility for tracking work activities moved to the remote work control station the shift supervisor no longer had a means of tracking surveillance work activity short term LCOs. During discussions with the operators and maintenance personnel it was determined that surveillances procedures involving short term LCOs can be completed well within the established time limitations. However, the use of surveillance procedures in work instructions did not ensure that the LCO action requirement would be met.

The inspectors subsequently reviewed the control room logs for the previous 3 days to assess the controls which had been imposed on entering the short-term action statement. It was noted that there were no control room log entries which identified when the trip unit had been placed in bypass and then returned to service. During the previous evening, the trip unit was taken to bypass on three different occasions without having been logged. In each case, the licensee was required to enter the associated 2-hour action statement. The inspectors verified that the licensee had not exceeded the 2-hour action statement.

Following the completion of the work activity, the inspectors discussed the overall job performance with licensee management. It had been identified that the short-term action statement had been entered on 10 separate occasions to complete the troubleshooting activity. Not until the end of the activity did management involvement become apparent. The lack of a comprehensive plan contributed to the RCIC system remaining out of service for almost the entire 14-day action statement period. The licensee initiated actions to ensure short-term action statements were appropriately controlled by the operators and implemented a short-term action statement log similar to that previously utilized. The inspectors periodically audited the log, and noted, through the end of this inspection period, that this action appeared effective in keeping track of short term action statements entered.

5.2 Calibration of Stator Cooling Water Temperature Monitors

On October 5 and 6, 1993, the inspectors observed the safety-significant portions of the calibration of the main generator stator cooling water temperature monitors. The work was to be accomplished in accordance with MWO R059547. This instrument was designed to initiate a main turbine runback if stator cooling water outlet temperature exceeded a certain temperature. It also was designed to alarm at a slightly lower temperature and lock shut the cooler bypass to maximize cooling. One of the channels was indicating a high temperature.

With the plant running at full power, an error during the calibration process could have caused a runback and resultant reactor scram, thus challenging the reactor protection system and subjecting the reactor to an unwanted transient.

To prevent a turbine trip and/or runback, the MWO specified lifting the two actuation circuit leads in the control room back panel and checking that there was no voltage at the lifted lead prior to reconnecting to restore the system subsequent to the calibration.

On October 5, when the technicians completed all of the appropriate briefings and job walk-downs, and had obtained the proper release from the operators to lift the leads, they took the initiative to check the terminals for the absence of voltage before disconnection. This was not required by the MWO. Voltage was present, giving the technicians reason to analyze the circuit diagrams for an explanation. They decided that the voltage was normal, but began to question the accuracy of the MWO step that required no voltage to be present prior to reconnecting the leads.

As the discussion continued, the inspectors questioned whether checking for voltage at the points specified by the MWO would reveal the presence of a runback/trip signal at all, because the specified points were only on one side of the circuit and, thus, appeared to provide inconclusive information as to whether or not a signal was present. The technicians concluded that the MWO appeared inadequate to perform the checks that were intended to prevent a turbine runback and trip while at full power, because the MWO appeared to specify the incorrect terminals to check for voltage. The I&C foreman supervising the activity shut down the job in order to correct the MWO and insure there were no other errors. The MWO was later revised to specify the correct terminals.

Prior to this evolution, there was considerable management attention focused on making sure that steps were taken to prevent a turbine runback or trip. However, the inspectors noted that only the planner and the I&C foreman approved the MWO. When the inspectors questioned the I&C foreman on the extent of his review, i.e., check the terminals specified by the MWO against the schematics, he stated that, based on his knowledge that there was prior system engineering involvement on the step, he assumed the step was correct and did not verify correctness.

The I&C Supervisor conducted a critique of the issue, and licensee management briefed the inspectors on intentions to take the following corrective actions to prevent a recurrence:

- Change Administrative Procedure ADM-0028, "Maintenance Work Order," Revision 11A, Section 4.13, to provide more specific guidance on what type MWOs must be reviewed and approved by System Engineering.

- Provide additional training for System Engineers on the subject of high risk MWO reviews.

- Provide clear expectations on this issue to maintenance personnel and system engineers.

- The Near-Term Performance Improvement Plan will address improvements over the management of high risk evolutions, i.e., evaluations that can result in the challenge of safety-related equipment.

Although this issue involved nonsafety-related equipment, the potential for a reactor scram was present. The technicians' timely identification of the error and their questioning attitude and the foreman's willingness to stop the work until all questions were resolved were appropriate. The corrective actions listed above appeared to be appropriate to the circumstances.

5.3 Overhaul of Safety-Related Motor Operated Valve

On October 5, 1993, the inspectors observed preventive maintenance being performed under MWO R170134 on the safety-related chilled water compression tank make-up water valve. The MWO was written to give general instructions to refurbish and to perform a static signature test on this motor-operated valve. The inspectors observed that the licensee was using an official work copy of Corrective Maintenance Procedure CMP-1282, "Limitorque Model SMB-000 Overhaul," Revision 0, during actuator disassembly. This procedure was found to be adequate and sufficiently detailed. The inspectors verified that the calibration of metering and test equipment was current and appropriately logged in the procedure.

The inspectors reviewed associated Clearance RB-1-93-6870 to confirm that equipment was properly removed from service. Technical Specification Limiting Condition for Operation 3.7.2 was being properly observed.

The inspectors verified that the craftsmen's training records were up to date and that their foreman signed the training sheet in the MWO package. The craftsmen appeared to be knowledgeable of their work and they followed the specific job plan.

Quality control hold points were appropriately observed, and all replacement parts and material were verified to be certified. The licensee's quality control inspectors performed the appropriate inspections and maintained a good level of coverage.

5.4 Verification of Untested Control Circuits in Annulus Mixing System

On October 28, 1993, the inspectors observed the Train A portions of the verification of relay contacts and wiring continuity in annulus mixing system control circuits in accordance with MWO R059557. This work was developed from CR 93-0644, which identified logic system functional test (LSFT) overlap deficiencies discovered during surveillance test procedure reviews. The reviews were being conducted as corrective action stemming from an initial discovery of LSFT overlap deficiencies in the RCIC system documented in NRC Inspection Report 50-382/93-05.

The operators were promptly notified when the LSFT reviewers discovered that certain loss of coolant accident relay contacts and wiring were not tested to verify the capability of placing one annulus mixing fan in standby after automatic initiation and allowing an automatic restart of the fan if a low flow condition is subsequently detected. This discovery rendered both redundant trains of annulus mixing inoperable, so the operators entered

Technical Specification 3.0.4, which allows 24 hours for the licensee to complete the missed surveillance test before it becomes necessary to implement a plant shutdown on a loss of safety function.

With the plant at full power, it was not practical to amend the 18-month LSFT and perform it, because it was designed for performance during cold shutdown conditions. Therefore, the MWO was utilized to verify only the contacts and wiring not covered by the test.

The electricians obtained an appropriate clearance by the operators to allow this work, which was to open the breaker supplying power to annulus mixing Fan A. The MWO specified the coordination requirements, precautions, and which leads to lift to verify the untested circuits were operable by use of an ohmmeter.

Leads were lifted, restored, and independently verified in accordance with maintenance department administrative controls. The electrical foreman was present during the work, and good coordination was demonstrated between the electricians and the operators.

Train A was successfully verified operable well within the 24-hour period, which placed the plant in a 7-day shutdown Technical Specification action statement. The circuits and relay contacts in Train B were subsequently verified satisfactorily.

5.5 Troubleshooting of RHR System Valve

On October 27, 1993, the inspectors observed troubleshooting activities associated with the failure of RHR Pump B shutdown cooling suction Valve 1E12*F006B. During inservice testing, the valve failed to stroke open and tripped the breaker at the Motor Control Center. Troubleshooting instructions were implemented by MWO R172573. The electricians noted, while walking down the job, that the instantaneous breaker trip setpoint adjusting screw was pointing to the "low" setting that corresponded to a trip setpoint of 32 amperes. Upon reviewing the applicable drawings, the electrical foreman found that the breaker could be set to trip at up to 44 amperes, so he concluded that previous trip may have been a "nuisance" trip. He informed the inspectors that motor starting current can be as much as 700 percent of running current, which equated to about 28 amperes. They reset the screw to point to a number corresponding to 41 amperes. The valve was then stroked again, with a clamp-on ammeter attached to a power lead. Motor starting current was not obtained because of an anomaly with the clamp-on ammeter, but running current was about 4 amperes. The valve was stroked again, and starting current was about 11 amperes, with a running current of 4 amperes. This equated to about 300 percent. The licensee may not have duplicated the problem that caused the breaker to trip and, therefore, did not establish the cause of the problem. The inspectors questioned what the cause of the breaker trip was and why the breaker was not retested to confirm that the trip point was in fact at 41 amperes and not in excess of 44 amperes. Licensee management indicated that they had similar questions and that the work plan appeared inadequate to resolve these questions.

MWO R155357 was generated to remove the breaker and test the instantaneous trip points. On November 4, 1993, the inspectors witnessed the test conducted in accordance with the MWO and Preventive Maintenance Procedure PMP-1020, "Preventive Maintenance of Thermal Overload Relays, Unitized and Molded Case Circuit Breakers," Revision 4. The test results were satisfactory. The "low" setting was within tolerance, i.e., was found at 26.5 amperes while the minimum was 25.6 amperes and the maximum was 44 amperes.

At the end of this inspection period, there was no problem with the breaker, except the breaker setting appeared close to locked rotor current. The valve was functioning normally. The licensee had not come to a formal conclusion as to what the cause of the valve malfunction was, i.e., why the breaker tripped when the operator attempted to open the valve during inservice testing on October 27, 1993

Failure of MWO R172573 to specify a retest after the electricians had made an adjustment to the instantaneous trip setting is a violation (458/93027-2) of 10 CFR Part 50, Appendix B, Criterion XI. Failure to provide an appropriate retest following maintenance activity was the subject of a violation in NRC Inspection Report 50-458/93-05.

5.6 Conclusions

The RCIC troubleshooting activity was not well coordinated. The licensee had not developed a comprehensive troubleshooting plan to minimize the number of times the short-term action statement was entered. The work coordination between engineering and I&C was not effective in that each individual's responsibilities were not well understood. Operations had not required that a comprehensive troubleshooting plan be developed until late in the work activity, when coordination problems surfaced.

Failure to provide an adequately reviewed, technically correct work instruction to prevent a turbine trip and/or runback demonstrated a weakness in the licensee's MWO process. This was mitigated by the questioning attitude of the I&C technicians and the willingness of the I&C foreman to stop the job and make sure all questions were addressed before proceeding.

The electricians' performance in refurbishing the safety-related chilled water compression tank makeup water motor-operated valve was good.

Verification of untested control circuits in the annulus mixing system was well planned, well executed, and satisfied the overlap deficiency identified during logic system functional surveillance test procedure reviews.

A violation was identified for failure to specify a postmaintenance test following the adjustment of the instantaneous overcurrent trip setting on the breaker supplying power to safety-related motor-operated Valve 1E12*F006B.

6 BIMONTHLY SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the surveillance testing of safety-related systems and components addressed below to verify that the activities were being performed in accordance with the licensee's approved programs and the Technical Specifications.

6.1 RCIC System Isolation Surveillance Test

The inspectors observed the performance of Procedure STP-207-5255. This surveillance was being performed to return the RCIC system to operation following troubleshooting activities discussed in Sections 2.1 and 5.1 above.

During the preparations to perform the surveillance test, an I&C technician noted that the new trip unit had not undergone a "burn-in" period. This was required to ensure that the trip had stabilized and would maintain the set calibration. A review of the troubleshooting work order did not identify the need to provide the "burn in." The start of the surveillance was delayed approximately 5 hours until the required initial conditions were met.

The inspectors noted that the I&C technicians were cognizant of the test requirements and utilized good self-checking techniques. The surveillance was appropriately reviewed with the operators and the short-term action statement was entered into the control room log in accordance with managements' expectations. During the performance of the surveillance test, the I&C technicians ensured the operators were aware of all expected alarms.

6.2 Division III DG Operability Test

On October 20, 1993, the inspectors observed the performance of the Division III DG monthly operability test in accordance with Surveillance Test Procedure STP-309-0203, "Division III Diesel Generator Operability Test," Revision 9A.

During procedure Section 7.3, "Pre-start Preparation," the inspectors noted that the requirement of subparagraph 7.3.5.14 to place the engine control switch to "auto" was not performed after completion of subparagraph 7.3.5.13. Up to this point, the steps were being performed in sequence, as required by Administrative Procedure ADM-0015, "Station Surveillance Test Program," Revision 14, Section 8.1. Instead, the operator skipped to Section 7.3.7, which also required the DG to not be in "auto." The operator appeared to believe that this change in sequence was allowed. There was nothing technically wrong with the operator's actions, except that it was later found not to be in compliance with Procedure ADM-0015.

The operator later informed the inspectors that he reconsidered the appropriateness of his actions as he was signing off the official copy of the completed procedure, and initiated a CR 93-0632 to identify the procedure violation.

Operations management performed a review of the incident in accordance with Operations Section Procedure OSP-0018, "Operations Accountability Review," Revision 1. They evaluated the completed Procedure STP-309-0203 and concluded that the acceptance criteria were not affected. The accountability review concluded that the incident was an operator error caused by inattention to detail. A causal factor was that the procedure could have been arranged better to eliminate the condition that led the operator to believe he could improve the sequence. Operations management pointed out that there was an ongoing effort to improve human factors in operating procedures. Based on observation of the test and review of a copy of the completed test document, the inspectors concluded that the acceptance criteria were not affected.

The inspectors expressed concern that apparently not all operators have disciplined themselves to follow procedures by stopping and asking questions of their supervision when it becomes necessary or advantageous to deviate from an appropriate procedure.

Failure to conduct Procedure STP-309-0203 procedure steps in sequence as required by Procedure ADM-0015 is the first example of a violation (458/93027-3) of Technical Specification 6.8.1.d.

6.3 Pressure Regulator System Tuning and Dynamic Response Verification

On October 2, 1993, the inspectors observed performance of portions of Test Procedure 93-0017, "Pressure Regulator System Tuning and Dynamic Response Verification," Revision 0. The inspectors observed the performance of Test Condition 5, which was the 90-95 percent reactor power pressure regulator step change. The test briefing was conducted in the control room at 11:15 a.m. The briefing covered the precautions and limitations, the expected pressure and flux variations, and criteria which would necessitate termination of the procedure. The inspectors observed good communication between the test director, test personnel, and Control Operating Foreman during the conduct of each step of the procedure. Action steps were repeated back to the test director for confirmation prior to their actual performance. The inspectors verified that all test data were properly recorded and within the allowable limits. The test was successfully completed at 12:35 p.m. The test was run in an orderly manner, all personnel appeared to perform properly, and the procedure appeared to be well written and supportive of the successful completion of the test.

6.4 Inservice Testing of Division II Low Pressure Core Injection (LPCI) Pumps

On October 27, 1993, the inspectors observed portions of the inservice testing of the Division II LPCI System pumps. The test was to be conducted in accordance with Procedure STP-204-6302, "Division II LPCI (RHR) Pump and Valve Operability Test," Revision 4. This testing was required by ASME Code Section XI and Technical Specifications 4.6.3.3 and 4.5.1.

The operators performing the surveillance obtained proper authorization from the control room, held a prebriefing with the shift supervisor, and set up proper communications between the operators and the main control room.

During the use and installation of the test gauges, the inspectors observed the operator experiencing difficulty following the procedure. The procedure required the operator to check the position of an equalizer valve that did not apply to the installation of the suction pressure test gauge. The operator did not put his hand on the valve to verify the position, but signed the step off and continued to the next step. Subsequently he stated he checked visually, though the method was not appropriate. The operator didn't follow the procedure sequence in that, after each test gauge was connected, the operator opened the corresponding isolation valve before installing the next gauge. The procedure directed the operator to install all test gauges, followed by instructions to open the isolation valves. Also, the procedure required all test gauges to be at the height of the installed gauges, but the operator recorded a measurement from a test differential gauge that was at a different height than the installed gauge.

The surveillance test was stopped after the operator noticed that a correctly installed test gauge was showing a different reading than the permanently installed gauge. At that point, the operator decided to stop the test to determine why there were two different readings.

The inspectors reviewed Procedure STP-204-6302 for quality and adequacy and found that it did not contain all of the information necessary to restore the system to its proper line-up. The procedure required the operator to open two locked valves, but the procedure recovery section did not contain a statement that required the operator to relock these valves. After bringing this and the above observations of the inspectors to the licensee's attention, the licensee decided to revise the procedure and revalidate it before performing the surveillance again.

On November 5, 1993, the inspectors observed the second effort to perform the inservice testing of the Division II LPCI pumps. The test was conducted in accordance with Procedure STP-204-6302. The inspectors reviewed the procedure and found it to be in a better format, and all of the steps provided sufficient detail.

The test was performed in a deliberate, step-by-step manner, with good communications between operators. The operators appeared very knowledgeable of the new surveillance procedure. The only problem the operator experienced was when the procedure was being followed to equalize the pressure on both sides of a differential pressure test gauge; the gauge pegged high. The system engineer, who performed the final review on the procedure, failed to recognize that the valve line-up that the procedure called for was inadequate for equalizing the pressure on the test gauge. The installed equalizing valve was designed to equalize only the permanently installed gauge. The operators stopped work to perform a procedure change notice. After a 45 minute delay, testing continued with the procedure change notice incorporated into the procedure. The changed procedure adequately equalized the pressure across the differential pressure test gauge. The components under test performed well, giving the operator satisfactory data to confirm operability of the equipment.

Failure to follow Procedure STP-204-6302 as written and in the sequence shown, as required by Procedure ADM-0015, is the second example of a violation (458/93027-3) of Technical Specification 6.8.1.d.

Failure to provide an adequate procedure to perform surveillance testing of the Division II LPCI pumps is a violation (458/93027-4) of Technical Specification 6.8.1. Inadequate inservice testing procedures were identified in a Notice of Violation attached to NRC Inspection Report 50-458/93-05.

6.5 Conclusions

The RCIC surveillance test was conducted in accordance with the procedure requirements. Good self-verification techniques were utilized. Communications between the operators and the I&C technicians was appropriate to ensure the short-term action statement time limitation was reviewed and expected control room annunciators were identified prior to being received.

One example of a violation was identified for failure to follow the Division III DG operability surveillance test procedure sequence as required by station administrative procedures. This demonstrated that not all operators had achieved the level of procedure compliance expected by plant management.

Pressure regulation system testing and dynamic response verification accomplished on October 2 by the coordinated efforts of System Engineering, Reactor Engineering, and Operations was performed in an excellent manner.

A second example of a violation was identified for failure to follow procedures during an unsuccessful attempt to conduct inservice testing of the Division II LPCI pumps. In addition, a repeat violation was identified for failure to provide an adequate procedure for that purpose. Corrective actions taken by the licensee appeared to not be fully effective. After the procedure was corrected and revalidated, the test was performed satisfactorily. The procedure included more detail, and the new format enabled the test to be performed in an orderly manner.

7 FOLLOWUP (92701)

7.1 (Closed) Unresolved Item 458/93003-2: Lack of Control Pertaining to MRs and Preventive Maintenance Activities

During the inspection that was documented in NRC Inspection Report 50-458/93-03, a weakness was identified regarding a lack of control pertaining to the coordination of an MR and the preventive maintenance program for replaced equipment. This program weakness was identified in CR 93-0069. The inspectors reviewed the completed CR and discussed the circumstances and corrective actions described in the report with maintenance and engineering personnel. The inspectors were informed that the nonsafety-related steam vent dryer was replaced as part of MR 91-001. The new air dryer required a desiccant with a different stock number than that used in the old air dryer. The air dryer portion of MR 91-001 was completed and a memorandum was issued by design engineering that permitted the dryer to be placed in service. However, the preventive maintenance program was not updated to reflect the new desiccant stock number. The desiccant in the new air dryer was replaced with the desiccant for the old dryer before all other work specified in the MR was completed and the preventive maintenance program updated.

The inspectors determined that the licensee did have controls in place regarding coordination of MRs and updating preventive maintenance programs that were delineated in Engineering Procedure ENG-3-006, "River Bend Station Design and Modification Request Control Plan," Revision 8, and Interim Procedure Change IPC-3-006-5. The procedure specified that a partial completion package form shall be initiated and completed by the design engineer to authorize the use of a partially completed MR. The updating of the preventive maintenance program was also addressed in the procedure as part of the partial completion package closeout by maintenance. However, the memorandum that was used by the design engineer to authorize the use of the new dryer, prior to completion of the entire MR, did not address the updating of the preventive maintenance program. Therefore, the use of the memorandum resulted in the bypassing of existing procedural controls for updating the preventive maintenance program. The inspectors verified that the corrective actions specified in CR 93-0069 were appropriate to correct the use of the incorrect desiccant and prevent recurrence. The inspectors also discussed with the lead design engineer the ongoing design engineering self-audit of all MRs. The inspectors were informed that the review of all safety-related work MRs issued to date had been completed and no safety-related MRs were identified that had been worked but not completed using the approved MR or partial completion package process. The inspectors concluded that this issue was adequately addressed under the licensee's corrective action program and that a violation did not exist.

8 ONSITE REVIEW OF LERs (92700)

8.1 <u>(Closed) LER 458/93-007: Isolation of Main Steam Isolation Valves Due to Personnel Lack of Understanding While Unique Maintenance Conditions Prevailed</u>

The licensee reported that, with the reactor in cold shutdown, an isolation of inboard and outboard main steam isolation valves and main steam line drains occurred on April 20, 1993. The licensee determined that the operating crew did not understand the specific details of the turbine control logic for the unique maintenance conditions that existed at the time of the event. The unique conditions consisted of resetting the main turbine from a tripped condition in support of electrohydraulic control testing, concurrently closing the main generator output breaker during maintenance performed on the breaker.

The inspectors reviewed the investigation, root cause, and corrective action to prevent recurrence discussed in the LER. The investigation appeared to be thorough and clearly described the conditions which caused the isolation of the inboard and outboard main steam isolation valves and main steam line drains. The licensee determined the root cause to be a lack of understanding of the turbine control logic for the unique maintenance conditions. The inspectors verified that the corrective action to prevent recurrence was complete, which included:

- The placement of a warning statement in Operations Policy 009, Revision 3, regarding the receipt of isolation signals when performing work on the main generator output breakers.

- The placement of a precaution statement in the System Operating Procedure SOP-0080, "Turbine Generator Operation," Change 93-0352, Revision 7, to alert operators of the requirements in the operating policy.

- A change to the training program for requalification of licensed operators, TPP-7-11 Lesson Plan REQ-528-0, "Module 5 Industry Events/Operating Experience," to incorporate the changes made to Operations Policy 009 and Procedure SOP-0080.

- A change to the training program for initial license training, Hot License Operator System Training Lesson Plan HLO-059, "Electrohydraulic Control System," to incorporate the changes made to Operations Policy 009 and Procedure SOP-0080.

8.2 (Closed) LER 458/93-013: Trip of High Pressure Core Spray Pump Breaker Following Start Due to Failed Over-Frequency Relay

The licensee reported that, with the plant at 100 percent power, the high pressure core spray pump failed to start and run during a surveillance test. The licensee determined through extensive testing that the pump failed to start and run due to a failed over-frequency relay.

The inspectors reviewed the investigation, root cause, and corrective action to prevent recurrence discussed in the LER. As a result of the extensive testing performed on the failed over-frequency relay, the licensee determined that by simulating installed conditions (i.e., relay installed in an enclosed case and the capacitor in an enclosed case) the relay would trip at 60 Hertz, which was below the design value of 63 Hertz. A new relay was installed in the pump motor switchgear and the high pressure core spray pump successfully started and its operability was verified. In addition, the inspectors verified that the test procedure for the over-frequency relay was revised to provide better simulation of field conditions during testing. The test procedure for the over frequency relay was Maintenance Corrective Procedure MCP-1032, "Testing and Calibration of G.E. Relays IJF-51A," Revision 4. The inspectors considered the corrective action that was taken to be appropriate for early detection of component degradation and replacement prior to failure.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

R. E. Barnes, Supervisor, ASME/ISI
*R. C. Biggs, Supervisor, Quality Systems
*J. B. Blakely, Director, Predictive Programs
*J. E. Booker, Assistant to the Vice President
B. R. Burke, Director,Chemistry Supervisor
D. R. Clymer, Senior Human Performance Engineer
*W. L. Curran, Cajun Site Representative
*D. R. Derbonne, Manager, Nuclear Performance
L. L. Dietrich, Supervisor, Nuclear Licensing
R. G. Easlick, Radwaste Supervisor
E. C. Ewing, Assistant Plant Manager, Maintenance
C. L. Fantacci, Radiological Engineering Supervisor
*J. J. Fisicaro, Manager, Safety Assessment & Quality Verification
A. O. Fredieu, Supervisor, Maintenance Services
*P. E. Freehill, Assistant Plant Manager, Outage Management
*K. D. Garner, Licensing Engineer
K. J. Giadrosich, Director, Quality Assurance
P. D. Graham, Vice President, Nuclear Integration
*J. R. Hamilton, Manager-Engineering
W. C. Hardy, Radiation Protection Supervisor
H. B. Hutchens, Director, Nuclear Station Security
R. T. Kelly, Instrument and Controls Supervisor
G. R. Kimmell, General Maintenance Supervisor
J. W. Leavines, Supervisor, Nuclear Safety Assessment Group
*D. N. Lorfing, Supervisor, Nuclear Licensing
R. C. Lundholm, Supervisor, Mechanical Process Systems
*I. M. Malik, Supervisor, Corrective Action & Reviews
*W. F. Mashburn, Manager, Engineering Programs
C. R. Maxson, Supervisor, Performance Assessment Group
*J. R. McGaha, Vice President, RBNG
J. F. Mead, Supervisor, Control Systems
*W. H. Odell, Director, Radiological Programs
*S. R. Radebaugh, Acting Manager, Modification Construction
C. R. Coats, Electrical Maintenance Supervisor
*J. P. Schippert, Assistant Plant Manager, System Engineering
*M. B. Sellman, Plant Manager
B. R. Smith, Mechanical Maintenance Supervisor
M. A. Stein, Director, Plant Engineering
*K. E. Suhrke, Manager, Site Support
*R. P. Thurow, Assistant Plant Manager, Continuous Improvement
W. J. Trudell, Assistant Operations Supervisor
*J. E. Venable, Assistant Plant Manager, Operations & Radwaste
G. S. Young, Supervisor, Reactor Engineering

* Denotes personnel that 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 November 9, 1993. 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.