APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/94-06

Operating License: NPF-47

Licensee: Entergy Operations, Incorporated
P.O. Box 220
St. Francisville, Louisiana 70775-0220

Facility Name: River Bend Station

Inspection At: St. Francisville, Louisiana

Inspection Conducted: January 30 through March 12, 1994

Inspectors: W. F. Smith, Senior Resident Inspector
C. E. Skinner, Resident Inspector

Approved: J. E. Gagliardo, Chief, Project Branch C — Date 5/4/94

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite response to events, operational safety verification, maintenance and surveillance observations, preparation for refueling, inservice testing of pumps and valves, followup, and review of licensee event reports.

Results:

- The operators and supporting personnel demonstrated excellent teamwork in responding to, and correcting, the failure of the main turbine electric trip solenoid and, again, in response to the Division I Topaz Inverter failure (Sections 2.1 and 2.2).

- Housekeeping appeared to be degrading slightly with the influx of supplementary personnel to support the refueling outage scheduled for April 16, 1994. Measuring and test equipment (MT&E) was found in inappropriate locations, contrary to the licensee's administrative controls. A violation was identified with two examples of where this had occurred (Section 3.2).

- The licensee implemented the System Engineering Presentation process, which appeared to be beneficial in promoting ownership on the part of

system engineers for their assigned systems, and in addition providing valuable information to plant management with respect to system problems and system engineering performance (Section 3.6).

- Maintenance activities observed during this inspection period were generally good. Work instructions, though complex and time consuming to generate, usually provided the necessary procedures appropriate to the circumstances. Delays were experienced in obtaining properly certified parts for safety-related applications; however, licensee management was made aware of each delay and was already addressing the problem as a long term improvement (Section 4).

- A violation was identified for failure of the licensee to take corrective action prior to restoring pumps and valves from an alert status as required by ASME Code Section XI. Weaknesses continued to appear in the performance of inservice testing (IST) surveillances on safety-related pumps, further confirming the need for the licensee to implement the Inservice Testing Program Improvement Strategy in a timely manner (Sections 5.1, 5.2, and 7.1).

- With the exception of inservice tests, surveillances observed during this inspection period were performed well, and with satisfactory results. The test performers followed procedures and the procedures were adequate (Section 5.3, 5.4, and 5.5).

- The receipt, inspection, and storage of the new fuel assemblies in the spent fuel pool was accomplished in an excellent manner. Procedures were followed, and the licensee's staff worked as a team exercising care to insure there were no problems with the fuel to be used in Refueling Outage 5 (Section 6).

- The inspectors concluded that all of the new managers reviewed had met or exceeded the minimum qualifications of ANSI/ANS 3.1-1978, as required by Technical Specification 6.3. The inspectors also concluded that the Manager-Safety Assessment and Quality Verification (SAQV) met or exceeded the qualification requirements in Updated Safety Analysis Report (USAR), Section 17.2.1.2.4, based on review of the licensee's evaluation submitted, interviews with the individual, and observation of his performance since he was appointed in September 1993 (Section 8.1).

- The inspectors concluded that the licensee's efforts toward developing a standardized employee concerns program had all the elements necessary for a significant improvement over the existing program (Section 8.2).

Summary of Inspection Findings:

- Violation 458/93006-1 was opened (Section 3.2).

- Violation 458/93006-2 was opened (Section 7).

- Licensee Event Report 458/92-021 was closed (Section 9.1).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Documents Reviewed

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the plant was operating at 100 percent power.

On a weekly basis, power was reduced to 90 percent in order to conduct routine turbine testing; however, on February 18, 1994, the turbine electrical trip test malfunctioned (Section 2.1). Power was reduced to approximately 76 percent to troubleshoot and correct a binding position indicator on the electrical trip valve. Power was restored to 100 percent on February 21.

On March 11, power was reduced to 70 percent in order to facilitate control rod tests, inservice testing of main steam isolation valves, and repair a leaking packing gland on Feedwater Regulating Valve A.

The plant was at approximately 90 percent power at the end of this inspection period, and was restored to 100 percent by March 13. The ascension to full power was delayed to repair a failed pressure sensor associated with the steam supply permissive on the moisture-separator reheaters.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Failure of Main Turbine Electrical Trip Test

On February 18, 1994, at approximately 11:30 p.m., while performing the timed automatic sequence turbine generator periodic testing, a malfunction and lockout occurred.

Control panel indications showed that the lockout solenoid remained energized, because the trip signal generated in the test sequence had not cleared and did not reset. The reactor operator performing the test immediately recognized the condition and followed the procedure caution to not reset the system by pressing the stop-go-normal button. This caution was placed in the procedure to prevent an actual turbine trip as a result of the test circuit deenergizing the lockout solenoid, before repair of the malfunction could be accomplished.

System Engineering, Maintenance, and Operations Management were contacted. General Electric was also contacted to provide on-site assistance and advice on the status of the trip system. A Maintenance Work Order (MWO), with troubleshooting instructions, was generated and planned by Maintenance and System Engineering. The initial investigation required the installation of a single wire jumper, and multiple voltage readings were to be obtained. The work was reviewed by the Operations staff and verified by independent system engineers prior to implementation. The work was also briefed as an infrequent evolution to the operators and maintenance personnel on the next day (Saturday). Crews were trained in the simulator in preparation for removing the turbine from service, if required.

The information obtained from troubleshooting the test circuit and the planned actions were reviewed by the Facility Review Committee on Sunday morning. The operators commenced a gradual reduction in power in anticipation of having to shut down that evening because the surveillance interval was about to expire beyond the 25 percent allowance permitted by Technical Specification (TS) 4.0.2.

System Engineering identified the possibility that the linkage on the electric trip solenoid position indicator could have been binding. The MWO was revised to perform a partial disassembly of the linkage suspected to be binding. System Engineering, Maintenance, and Operations Management walked down the task. The linkage was found to be binding and was freed by a simple rotational adjustment. A condition report (CR) was generated to address the root cause. Retesting was performed several times with satisfactory results.

The plant power reduction was stopped at appropriately 76 percent power. All turbine testing, stop valve, and bypass valve testing was completed satisfactorily. Power was then restored to 100 percent power.

The licensee demonstrated excellent teamwork and management oversight and proceeded carefully and conservatively to avoid a potential turbine trip and resultant reactor scram. The desire to avoid a transient was of particular importance because of the leaking fuel assembly which could have been impacted by a transient.

2.2 Failure of Topaz Inverter Cooling Fan

On February 23, 1994, the chassis cooling fan for Division I Topaz Inverter 1E21A*PS1 experienced a bearing failure and became very noisy. Complete failure appeared imminent, and failure of the power supply would follow shortly thereafter. The topaz inverter was fed from the safety-related DC bus and supplied 115-volt AC power to a rectifier that, in turn, converted the power to 24 volts DC. This power was fed to a number of isolation trip units, the reactor core isolation cooling system, the automatic depressurization system, and the Division I diesel generator. Loss of this power supply while operating at power could possibly cause 1/2 isolations and render the diesel generator inoperable. Restoration voltage spikes have caused 1/2 isolations in the past.

The licensee generated MWO R200843 to replace the inverter and performed detailed planning and reviews coordinated between Operations, System Engineering, and Maintenance. This effort was to ensure that all affected trip units were identified to be placed in the tripped condition, in bypass, or otherwise disabled to prevent functional trips upon restoration of power. A portable fan was directed toward the power supply to supplement the failing fan while the MWO was being prepared.

During the evening shift, the operators conducted a briefing with the electricians and then established the conditions for inverter replacement. The inspectors observed this activity as well as the inverter replacement. Management oversight in all disciplines involved was evident during the replacement.

2.3 Conclusions

The operators and supporting personnel demonstrated excellent teamwork in responding to, and correcting the failure of, the main turbine electric trip solenoid and again in response to the Division I topaz inverter failure.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this 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

The inspectors observed control room operations on a daily basis when on site. Over the period of this inspection, the operator log entries appeared to be improving. The cryptic entries noted in previous resident inspection reports appeared to have subsided. However, one inaccuracy was identified on February 10, 1994, when Channel B indicated reactor vessel level diverged from Channel A by 6 inches, which tripped a control room alarm annunciator. The operators had noticed a diverging trend during the previous weeks, which was believed to be the result of undetected leaks in the piping and/or noncondensables forming in the condensing chamber. During their daily review of the control room logs, the inspectors noted that at 7:24 a.m. and 10:37 a.m. entries were made indicating that alarms were received and immediately reset and that nothing appeared to be abnormal. However, there was an abnormality, i.e., Channel B level indication was out of agreement with the other channels by nearly 6 inches. At 2 p.m., a 7-day TS shutdown action statement was entered because of the abnormality. The inspectors discussed the log entries with the operators and the assistant operations supervisor. They considered the log entries to be appropriate, because they were already aware of the level divergence and were documenting the fact that there were no other abnormalities. After discussing the log entries with the Assistant Plant Manager (APM), Operations, he stated that he did not consider the log entries to have satisfied the licensee's expectations, and he was still in the process of improving log keeping practices. This response was acceptable.

Clear communications were evident between operators, and between operators and supporting organizations. Each time the inspectors questioned the presence of new or old annunciator lights, the operators were knowledgeable and provided clear explanations.

3.2 Plant Tours

Throughout the inspection period, the inspectors toured various accessible areas of the plant and found the following: (1) a pressure gauge (aneroid barometer) labeled nonradiological controlled area (non-RCA) was in the fuel building, which was within the RCA; (2) a Fluke digital meter with an expired calibration due date was also in the fuel building, contrary to the licensee's administrative

controls; (3) two ladders were not being stored in a designated storage area when not in use, one additional ladder was left unattended and unsecured. During inservice testing of the service water recirculating pumps (Section 5.2), a weakness was identified by the inspectors on how the operators controlled the use of a ladder in proximity of safety-related equipment during the surveillance test. The operators failed to follow the memorandum issued by the plant manager. The ladder was not secured at all times when in place and the ladder was not stored in a designated location when it was not in use; (4) two red plastic bags containing wrenches and a shirt were left unattended and not labeled on ventilation ductwork in the "T" Tunnel; (5) assorted tools were left in a pile on the 141 foot elevation for at least 2 days with no work in progress; (6) the funnel under the inlet of Air Compressor LSV*C3A was clogged and overflowing on the auxiliary building passageway floor; (7) there was a scaffold plank installed against Class 1E Panel 1EHS*MCC2C; (8) loose and missing fasteners in the hub of Security Door AB070-04 were found with no deficiency tag; (9) the Division I safety-related battery was found to have a buildup of corrosion products on one terminal of Cell Number 43, and a dust cover on the breather for Cell Number 32 was broken. The dust cover was replaced, and the corrosion was evaluated as acceptable in view of near-term plans to clean and apply antioxidant to all terminals during Refuel 5. The shift supervisor was informed of the above items and took appropriate actions to correct the inspectors' observations. These observations were indications that all plant staff are not yet on board with the licensee's expectations in housekeeping.

Procedural controls are required by TS 6.8.1 for ensuring that M&TE are properly controlled and calibrated. Administrative Procedure ADM-0029, "Control of M&TE," Revision 11, states that the user shall insure that M&TE issued from the cold tool room is not used in the radiological controlled area. The system engineer that checked out the gauge from the cold tool room explained to the inspectors that he had expressed his intent to use the gauge first outside the RCA, then inside. He could not explain why he placed M&TE labeled "non-RCA" into the RCA. The failure of the user to keep the pressure gauge out of the radiologically controlled area is an example of a failure to follow procedures and is considered a violation (458/9406-01).

Procedure ADM-0029 further stated that the M&TE Issue Facility had the responsibility to ensure that all M&TE due for calibration is recalled and removed from use in the field. A recall notice was issued for a Fluke digital meter, but the meter was not removed from the field. Failure to remove the digital meter from the field with the overdue calibration date is the second example of a failure to follow procedures (458/9406-01).

While both examples were of minor safety significance and did not result in contamination of the gauge, nor use of M&TE that was out of calibration, they did demonstrate an apparent lack of attention to detail on the part of plant staff members to ensure that administrative requirements were being met.

3.3 Security Observations

The inspectors observed various security officers at their post and, in particular, those performing their duties at the primary access point for the Protected Area. They appeared to be alert and attentive to their responsibilities.

3.4 Radiation Protection Activities

On February 27, during a plant tour, the inspectors noted that there were repeated alarms from Plant Stack Monitor RMS*RE126, with the horn frequently sounding at the unit. Alternate radiation Monitor RMS*RE125 had been inoperable with a failed sample pump. Two days later, the Radiological Engineering Supervisor found that the foil on the detector on Monitor RMS*RE126 had a pinhole causing spurious high radiation readings, thereby causing the alarms. TS operability requirements were met, and the TS limits for gaseous effluents were not exceeded. By March 1, Monitor RMS*RE125 was restored to service and, subsequently, the detector on Monitor RMS*RE126 was repaired. On March 10, the inspectors reviewed the alarm status of Monitor RMS*RE126 and found that it no longer was indicating an alarm state. The actions taken by the licensee were appropriate.

The inspectors also noted during tours of the RCA that contaminated area control points were being maintained in an improved condition. No bags overstuffed with anticontamination clothing were found, as had been reported previously.

3.5 Overtime

On February 5, 1994, while reviewing the CRs generated on the previous day, the inspectors noted that two operators had worked greater than 24 hours in a 48-hour period by approximately 2 hours (CR 94-0163). Authorization had not been obtained from the Plant Manager or his designee as required by TS 6.2.2.4. The licensee did not consider it to be a TS violation because the individuals spent the 2 hours in a holding station waiting for inert fission gases to decay off of their clothing. Because they were not performing work, the inspectors discussed the issue with NRR and Region IV management. The results were that, as long as the operators were not engaged in licensed activities, and provided they had a break of at least 8 hours thereafter, which they did, being at rest for gas decay could be construed to add no more to fatigue than shift turnover time. The inspector questioned the licensee as to what controls were in place to make sure this interpretation would not be abused. On March 8, the Operations Superintendent issued a memorandum amplifying the procedural guidance for overtime to ensure that, if an operator is held over for gas decay, he will have at least 8 hours of rest between work periods. If not, the individual's work schedule would be changed to provide at least 8 hours of rest. The licensee has placed adequate controls on this issue.

3.6 System Engineering Presentation

On February 28, 1994, the licensee implemented the first of a series of periodic System Engineering presentations where the assigned system engineer for a given system conducted a meeting with key plant staff managers to give: (1) a brief system overview and operating history, (2) an overview of system testing, preventive maintenance and surveillance, and (3) a review of system performance problems, corrective action, and status. The inspectors attended the first session, which was on the reactor recirculation system. There was good interaction between the attendees and the presenter, and the presentation was informative. This process appeared to be beneficial to plant management and the assigned system engineers in that plant management received performance data on the subject system, and were given an opportunity to evaluate the system engineer's cognizance over his system. It also appeared to promote system ownership on the part of the system engineers.

3.7 Conclusions

Control room operations continued to be conducted in a formal, professional manner with crisp, accurate communications demonstrated between operators, and between operators and supporting organizations.

Housekeeping appeared to be degrading slightly with the influx of supplementary personnel to support the refueling outage scheduled for April 16, 1994. In addition, MT&E was found where it should not have been. A violation was identified with two examples of failure to follow administrative controls related to MT&E.

The licensee's System Engineering presentation process appeared to be beneficial in promoting ownership on the part of system engineers for their assigned systems and, in addition, provided valuable information to plant management with respect to system problems and system engineering performance.

4 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 TS, and NRC Regulations.

4.1 Overhaul of Safety-Related Motor Operated Valve

On January 31, 1994, the inspectors observed a scheduled overhaul of Valve 1E12*MOVF096 in accordance with MWO R173852. This valve was an emergency cross-connect between low pressure core injection Path B and service water. The inspectors verified that the safety-related motor-operated valve motor pinion was properly installed and locked in place. This was a followup to a previous issue documented in Section 2.3 of NRC Inspection Report 50-458/93-026, regarding a

motor-operated valve failure to function, which was originally identified by Cooper Nuclear Station, because a motor pinion key and set screw had become disengaged.

The inspectors verified that the craftsmens' training records were up to date and that their foreman signed the training sheets in the MWO package. The work package was found to be adequate and sufficiently detailed, and the instructions were followed by the craftsmen.

4.2 Maintenance on Penetration Valve Leakage Control System (PVLCS) Compressor LSV*C3B

During the period of January 18-23, 1994, the licensee implemented a design modification to PVLCS Compressor B to prevent seal water from constantly draining to the liquid radioactive waste system. Both Compressors A and B were significant contributors to waste when they were not running, because of a constant service water makeup and rejection while maintaining separator level at the required level. The modification was completed on January 23, but the operational test was unsuccessful because, in part, of foaming in the compressor and separator tank. Because the TS 7-day shutdown action statement was about to expire, the licensee reversed the modification process and restored the compressor to its premodification configuration and successfully tested it. The foaming issue was discussed in NRC Inspection Report 50-458/93-31.

On February 4, the inspectors observed maintenance work being done on the separator level control valve in accordance with MWO R200615. The inspectors verified that the correct TS action statement was entered and that Division I was operable. The purpose of the work package was to remove, inspect, and replace, if necessary, the level control valve. The licensee was not confident that foaming was the only problem with the compressor, because there was a slight air leak on the level control valve. The leak was repaired and the valve seat was replaced by February 8, after approximately 4 days of work and delays in obtaining parts. The inspectors noted that the technicians used good work practices and the MWO had sufficient detail to accomplish the task.

On February 8, the compressor was operationally tested and again failed to maintain proper separator level. Licensee representatives stated that they believed the separator was not being properly vented, so a modification was implemented to install a constant vent with a small orifice that would not measurably affect compressor capacity. On February 10, the inspectors observed the mechanical maintenance technicians installing the vent in accordance with MWO R200629. The MWO was followed, and the inspectors found no problems with the technicians' performance. Later on February 10, the compressor was tested, but still could not maintain separator level as required for operation. After extensive troubleshooting and analysis, the licensee removed the constant vent.

Still later on February 10, several successful runs of Compressor B were completed. The TS action statement was exited at 5:50 a.m. on February 11. The

licensee then decided to assure reliability of the compressor by performing the monthly operability test on a daily basis for the first week, then on a weekly basis for the next 3 weeks.

On February 12, the compressor tripped on low separator level during the daily surveillance test. Low level conditions in the separator tank were believed to have been caused by foaming of the water, malfunctioning of the separator level control valve, and loss of separator water through the air intake. Although the compressor had been run successfully since this occurred and the separator level control valve had been repaired, Engineering determined that the inlet check valve should be reinstalled and the unloader valve should be restored to service.

On February 17, the licensee requested enforcement discretion from the NRC staff to allow time for proper modifications of the compressor as originally planned in January. The discretion was not to exceed 21 days from February 12, which was consistent with the 30 day out-of-service period permitted by the Improved TS. The request and supporting information was reviewed and approved by the River Bend Facility Review Committee. The enforcement discretion was verbally granted by the NRC staff and, on February 28, a Notice of Enforcement Discretion was issued.

The licensee proceeded with the modification of the compressor and continued to troubleshoot and analyze the compressor performance. By February 28, the modifications were completed. The separator unloader was reactivated, a check valve was placed in the compressor inlet, and the solenoid valve controlling makeup seal water was set up to be open during compressor operations and to respond to separator level demands while the compressor was shut down, such that separator level would be always maintained.

The licensee conducted the operability surveillance test during the morning of February 28, but level could not be sustained in the separator again. It was apparent that the only possible cause was the level control valve being stuck open. This valve was a standard float valve. The valve was disassembled, and the licensee found that the valve stem had sufficient clearance with the float arm such that when the level decreased, and the float lowered the valve to the valve seat, the pointed end of the valve could miss the seat orifice completely, coming to rest to the side of the seat. This would cause overdraining of the separator, resulting in a loss of level.

The licensee consulted with the valve vendor and added a flat washer to the valve stem, thus keeping the valve in alignment with the seat for proper operation of the valve.

On March 1, repeated operational tests were successfully completed and the TS action statement was exited.

In order to better assure reliability and early identification of problems, the licensee increased the frequency of the monthly operability surveillance test to weekly until the refueling outage of April 16, except that on two occasions they would not run the test because a Division I outage was in progress.

To completely eliminate the potential of foaming in the compressor and/or separator, and to improve overall service water system water chemistry, the licensee completed a feed-and-bleed operation followed by connecting a reverse osmosis purifier to the system, thereby reducing total organic content from 1300 parts per million to about 20 parts per million.

The licensee's performance in resolving the many problems associated with this maintenance challenge was mixed. Delays were experienced because of the complexity of the MWO process and difficulties in obtaining safety-grade parts. The licensee stated that they intended to critique the process to identify all of the weaknesses and has made some assignments to implement the Long Term Performance Improvement Plan items related to maintenance process improvements.

4.3 Troubleshooting of Residual Heat Removal (RHR) Electrical Breaker

On February 7, 1994, the inspectors observed troubleshooting and repair of the electrical breaker that supplied power to the RHR Pump C miniflow valve. When RHR Pump C was started, the breaker tripped unexpectedly, causing the miniflow valve not to function as designed. The work was being accomplished in accordance with MWO R202891. The RHR C system was declared inoperable and the operators entered the required TS action statement.

Throughout the maintenance process, the inspectors noticed that the foreman in charge provided good oversight in the shop and in the field. The inspectors verified that the electricians were qualified and that the calibration of MT&E was current and appropriately logged in the work package.

The electricians removed the breaker from the radiologically controlled area and performed all troubleshooting activities in the electrical shop. During the removal of the breaker, the electricians noticed a broken spring clip in the breaker cubical. The job plan was revised to include the replacement of the spring clip. In the shop, the craftsmen determined that the trip current was not correct, therefore, the trip coil was replaced. After further testing, the trip current was still found to be incorrect. The electrical foreman decided to replace all of the breaker internals to make certain that the problem was resolved. Just prior to installation of the repaired breaker, the electricians tested the visual trip signal one more time, and the visual indication failed to work. The work package was revised to either fix or replace any necessary parts. The craftsmen found the trip indicator linkage was improperly manufactured without the proper curve in the linkage. The trip indicator linkage was replaced. The visual trip signal was retested and found to work properly.

RHR C was successfully verified operable within the 7-day shutdown TS action statement. This maintenance activity was well planned and executed in the repair of the electrical breaker, but the licensee did not determine the cause of the breaker malfunction, i.e., why the breaker tripped when the miniflow valve started to close. The inspectors questioned why, and the licensee responded that the evidence of failure, if any, was lost when the breaker internals were removed for replacement. While developing the response, the licensee reviewed the history of failures of this type and found no adverse trends. In addition,

licensee representatives stated that they were revising the training for electricians and were considering changing the planning guidelines for troubleshooting to capture the evidence of the causes of breaker failure causes whenever possible. This action will be reviewed and evaluated by the inspectors when completed.

4.4 Correction of Reactor Vessel Level Indication Divergence

On February 14, 1994, while the plant was operating at full power, the inspectors observed portions of the reactor vessel water level instrument reference leg backfilling process in accordance with MWO R202896.

The inspectors reviewed the procedure implemented by the MWO, Maintenance Calibration Procedure MCP-4189, "Reactor Vessel Reference Leg 1B21*TKD004B Isolation, Filling, and Purging," Revision 5. The procedure had just been revised and human factored. The inspectors noted a few minor discrepancies but, after the technicians completed their walkdown and review, a 32-page change notice was written to correct editorial errors in the 56-page procedure. This demonstrated good attention to detail on the part of the technicians, but did not reflect well on the procedure writers and the procedure review process.

The operators and technicians conducted an appropriate prejob briefing in the control room to ensure that all involved personnel were familiar with the evolution and its impact on plant conditions.

The inspectors observed implementation of that part of the procedure that aligned the equipment that had the potential to respond to the Channel B reference leg and generate a false trip. The work observed was done carefully in a step-by-step manner. The operators subsequently inserted a 1/2 scram and 1/2 of a main steam and balance of plant isolation within 1 hour, pursuant to the requirements of TS 3.1.1 and 3.1.2, respectively, because the alignment process rendered the affected channels inoperable.

The backfill process went smoothly and the postmaintenance test was appropriate for the work done and was satisfactorily completed.

4.5 Conclusions

Maintenance activities observed during this inspection period were generally good. Work instructions, though complex and time-consuming to generate, usually provided the necessary procedures appropriate to the circumstances. Delays were experienced in obtaining properly certified parts for safety-related applications; however, licensee management was made aware of each delay and was addressing the problem as a long term improvement.

5 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.

5.1 Inservice Testing of Division II Standby Liquid Control (SLC)

On February 10, 1994, the inspectors observed the inservice testing of SLC Pump B in accordance with Surveillance Test Procedure (STP) 201-6312, "SLC Quarterly Valve Operability and Pump Flow Test Division II," Revision 1.

The test was first performed on January 11, which was documented in NRC Inspection Report 50-458/93-031, Section 5.4. The licensee stated that the pump suction pressure reading of "5+ psig," when the gauge was pegged high, was adequate because the suction pressure met the acceptance criterion of greater than, or equal to, 1.7 psig. The inspectors questioned whether the licensee was meeting the requirements of Section XI of the ASME Boiler and Pressure Vessel Code which includes the suction pressure as one of several parameters to be measured and used for trending. The purpose of repeating part of the inservice test was to obtain the running suction pressure data.

The licensee performed a pretest briefing and marked all nonapplicable steps "N/A." After the briefing, the operators received the shift supervisor's permission to begin the test as required. The inspectors observed the operators as they installed test instrumentation and performed the partial test. The inspectors verified that the MT&E was in calibration and properly documented in the official copy of the test procedure.

The procedure had been changed to include a second isolation valve before the pressure gauge. The purpose of the second isolation valve was to prevent the suction pressure problem observed on January 11. The second isolation valve performed its intended function and the operators were able to obtain a satisfactory value for suction pressure.

Because the test was completed a month after its originally scheduled date, the inspectors verified that the test was completed within the required surveillance interval.

5.2 Inservice Testing of Division II Service Water Recirculation Pumps

On February 16, 1994, the inspectors observed the inservice testing of the Division II control building air conditioning service water recirculation valves and pumps. The test was conducted in accordance with STP 256-6322, "Control Building Chilled Water System Service Water Recirculation Quarterly Valve Operability and Pump Flow Test Division II," Revision 2. The purpose of this observation was to observe the licensee's progress in correcting procedure inadequacies related to inservice testing.

The day before conducting the test, the operators walked down the system, using the procedure to mark the placement of test gauges and connection points for the gauges. The labeling of gauge placement and connection points was to help collect consistent data from the gauges where location was important for data collection. This was an improvement over previous observations.

The operators performing the surveillance obtained proper authorization from the shift supervisor and established proper communications between the operators and the main control room. The test was performed in a step-by-step manner, with good communications between operators. The operators appeared very knowledgeable of the surveillance procedure.

After the operators obtained the data, it was determined that the pump was performing outside the acceptance criteria. The pump did not appear to be abnormal; however, when the operators checked all measurements a second time, the results were still unacceptable. The system engineer, who was present during the test, indicated that the operators may not have obtained accurate measurements from the gauge. The system engineer opened the instrument valve to obtain more accurate measurements; however, he did not close the valve after he was finished. Upon obtaining the data, the system engineer exited the area to retrieve the previous procedure revision (Revision 1) performed on the pump. When the system engineer returned and compared Revision 2 with Revision 1, he noted that the placement of the test gauges with respect to elevation had been changed. He then temporarily relocated the gauge to the position used during the previous test and concluded that inconsistent gauge location between tests was the problem. The test was stopped due to the pump not meeting the acceptance criterion for differential pressure, and the pump was declared inoperable. The test gauge valve was closed.

The licensee reviewed the procedure for any other problems and discovered that the procedure did not contain correct acceptance values for the vibration measurements. The procedure was revised again (Revision 3), incorporating the correct test gauge locations and vibration acceptance values.

On February 17, the operators performed Revision 3 of the test procedure with a one time change notice. The change notice allowed the operators to collect data to re-baseline the pump so that consistent values would be obtained in the future, based on consistent test gauge placement. The procedure allowed the operators to first gather data to determine the pump's operability status, then collect data to re-baseline the pump. The pump was declared operable with data taken from the gauges at the previous elevation. Another procedural problem was identified when the idle suction pressure of the pump could not be obtained due to the system's configuration. A procedure change notice was incorporated into the procedure and the test was continued without problems.

The inspectors questioned the above practice of an engineer manipulating a valve and then walking away without returning the valve to its original configuration. Administrative Procedure ADM-0022, "Conduct of Operations," Revision 16, did not allow this practice without permission from the Shift Supervisor or Control Operating Foreman, except during authorized testing using approved procedures.

The individual and the operators conducting the test indicated that they were under the impression that the exception applied in this case. The inspectors took exception to such a broad interpretation and expressed concern to licensee management. The individual was counseled and, to reinforce expectations, the System Engineering Manager wrote a memorandum to all system engineering personnel reinforcing the existing requirement that they were not to manipulate valves without specific permission from the Shift Supervisor or the Control Operating Foreman. This was not considered a violation of Procedure ADM-0022 but, rather, a nonconservative interpretation by individuals conducting the test. The licensee's actions to prevent future similar problems from system engineers was appropriate to the circumstances.

The events discussed above demonstrate the licensee's continued weaknesses in the IST area. The licensee's corrective actions for previous violations in this area have not been fully implemented. The inspectors will continue to observe the licensee's IST activities to evaluate progress on the improvements promised by the licensee.

5.3 Functional Test of Low Pressure Core Injection (LPCI) Pump A Discharge Pressure Instrument

On February 23, 1994, the inspectors observed the monthly channel functional test on the LPCI Pump A discharge pressure instrument in accordance with STP 204-4221, "Emergency Core Cooling System-LPCI Pump A Discharge Pressure-High Monthly Channel Functional," Revision 6. This functional test was required by TS 4.3.3.1 and 4.5.1.e.1.

While the technicians were preparing to perform the surveillance, the inspectors observed the technicians checking and logging the calibration dates of the M&TE in their procedure. The shift supervisor entered the appropriate TS action statement, which allowed 2 hours for the components of Division I emergency core cooling systems to be inoperable. During the test, the technicians maintained communications with the control room operators, informing them of alarms to be annunciated. All of the measurements obtained during the surveillance were found to be within the acceptance criteria, and then the system was restored to its original configuration. The shift supervisor then exited the TS action statement well within the 2-hour time allowance. The operator's performance during the conduct of this surveillance was good.

5.4 Surveillance Test of PVLCS Air Compressor LSV*C3B

On March 1, 1994, the inspectors observed the postmodification, channel functional test and operability test of PVLCS Air Compressor LSV*C3B in accordance with STP 255-4218, "PVLCS-Air Compressor C3B Auto Stop/Start, Monthly Chfunct, 18 Month Chcal (1LSV*PT22B, 1LSV*ESX22B, 1LSV*ESY22B)," Revision 5B. Proper communications were established between the test personnel at the compressor skid and the control room. When the compressor started, the water level was maintained in the separator and there was no evidence of foaming. Throughout the 1-hour run, the compressor performed well. The procedure was performed in a step-by-step manner by the technicians, and satisfactory results

were obtained. Based on the test results and instrument indications observed by the inspectors, the modifications to the compressor were successful.

5.5 Calibration of the Cooling Tower Blowdown Line Radiation Monitor

On March 10, 1994, the inspectors witnessed portions of the cooling tower blowdown line radiation monitor (1RMS-RE108) channel calibration as required by TS 4.3.7.10. The calibration activity was performed in accordance with STP 511-4281, "RMS-Radiation Monitor Cooling Tower Blowdown Line 18 Monthly Channel Calibration," Revision 5.

The technicians obtained the shift supervisor's permission prior to starting the surveillance and notified the control room operators of all expected alarms that would be received during the surveillance. The technicians established proper lines of communications with the control room during the surveillance. All test equipment used in this surveillance was verified by the inspectors to be currently calibrated.

5.6 Conclusions

Weaknesses continued to appear in the performance of IST surveillances on safety-related pumps, further confirming the need for the licensee to implement the IST Program Improvement Strategy in a timely manner. The inspectors considered it inappropriate for the system engineer to manipulate a gauge valve without specific permission from the shift supervisor or the control operating foreman; however, the licensee's action to prevent a recurrence was appropriate to the circumstances.

Other surveillance tests observed during this inspection period were performed well and with satisfactory results. The test performers followed procedures and the procedures were adequate.

6 PREPARATION FOR REFUELING (60705)

The purpose of this inspection was to ascertain the adequacy of licensee procedures and administrative controls for receipt of new fuel.

6.1 Procedure Review

The inspectors reviewed the procedures listed in Attachment 2, prior to observing the receipt, inspection, and storage of the new fuel assemblies in the spent fuel pool. The procedures were comprehensive, covered a thorough receipt inspection process, and included all of the precautions necessary to insure that the fuel assemblies were properly handled.

6.2 Observation of Fuel Receipt, Inspection, and Storage

On February 26, 1994, the inspectors observed the fuel vendor representative as he trained the fuel receipt inspection team on the first two fuel assemblies. The licensee utilized both maintenance personnel and quality assurance inspectors

for this process. Although maintenance personnel did the majority of the inspections, quality assurance personnel inspected some fuel assemblies on a random basis.

On March 8, the inspectors observed the entire process of new fuel receipt on at least five assemblies, starting with removal from the truck to storage in the spent fuel pool. This was the sixth truckload of fuel out of seven.

Procedures were followed and appropriate care was exercised in the handling of the fuel. Good teamwork was evident.

The inspectors found no problems with the fuel receipt process, except that there was no requirement to independently verify the torque applied to the single fastener that attached the fuel channel to the fuel rod bundle. Although the mechanics were using reasonable care, failure to properly tighten the fasteners could lead to loose parts in the reactor with potentially significant consequences. The licensee accepted the comment as an improvement item, and implemented a second verification with the remaining assemblies. Based upon the care being exercised, the inspectors did not consider it practical or necessary to reverify the torque on completed fuel assemblies that were already stored in the spent fuel pool.

6.3 Conclusions

The receipt, inspection, and storage of the new fuel assemblies in the spent fuel pool was accomplished in an excellent manner. Procedures were followed and the licensee's staff worked as a team exercising care to insure there were no problems with the fuel to be used in Refueling Outage 5.

7 IST OF PUMPS AND VALVES (73756)

7.1 Review of Pump and Valve Dispositioning

The inspectors conducted a focused review of the licensee's IST Program to determine if the licensee was meeting the requirements of Section XI of the ASME Boiler and Pressure Vessel Code when acceptance criteria were not met. The inspectors requested a listing from January 1993 to present of all pumps and valves subject to Code requirements that did not meet the inservice test acceptance criteria. The inspectors also requested information on what corrective action was taken for each component. During the review, the inspectors identified seven examples where a safety-related pump or valve was placed in an alert status and subsequently removed from alert status, 1-7 months later, without corrective action taken. Section XI, Articles IWV-3230 and IWV-3417, for pumps and valves, respectively, require that corrective action be implemented or the results be evaluated for acceptability before removing the components from the alert status.

When the inspectors questioned licensee representatives concerning why corrective action was not taken or an engineering evaluation performed before removing the pumps and valves from the alert status, the licensee stated that they increased

the test frequency as required by the Code but, when subsequent test results were satisfactory, the components were simply removed from the alert status and returned to the normal test frequency.

The following list of pumps and valves were removed from increased testing frequency to normal testing frequency without corrective actions being taken:

COMPONENT	NUMBER	FUNCTION
Centrifugal Pump	1SWP*P3D	Control Building HVAC Service Water Recirculating Pump
Centrifugal Pump	1E21*PC002	Division I Emergency Core Cooling System Line Fill Pump
Positive Displacement Pump	1C41*PC001B	Division II Standby Liquid Control Pump
Motor Operated Valve	1E12*MOVF064B	"B" RHR Pump Miniflow Valve
Air Operated Valve	1C11*AOVF180	Control Rod Drive Scram Discharge Volume Vent
Air Operated Valve	1SWP*AOV51B	Cooling Water Return from Air Compressor LSV*C3B
Air Operated Valve	1SWP*AOV51B	Cooling Water Return from Air Compressor LSV*C3B

Air Operated Valve 1SWP*AOV51B was removed from an alert status twice during the period considered, without corrective action having been taken in either case.

The River Bend Station has had a history of problems with the IST Program. Violations and weaknesses have been documented in NRC Inspection Reports 50-458/92-26, -92-35, -93-05, -93-25, -93-27, and -93-31. To permanently correct these problems, the licensee implemented an IST Program Improvement Strategy which set up a dedicated IST team under System Engineering. In the short term, the licensee wrote a CR to address the six components above that were identified by the inspectors. The licensee revised Administrative Procedure ADM-0015, "Station Surveillance Test Program," Revision 15, to require that System Engineering provide written concurrence prior to equipment being removed from an alert status. Also, System Engineering commenced engineering analyses on the above components to address removal from the alert status.

The failure to implement corrective actions when removing equipment from the alert status is a violation (458/94006-2) of Section XI of the ASME Boiler and Pressure Vessel Code.

The Quality Assurance Program identified a weakness in the IST Program during an audit conducted between January 28 and February 6, 1992. The audit,

92-01-I-IIPG, identified a concern that removing a component from increased frequency following the first test that yielded acceptable results was not in accordance with the requirements of ASME Code Section XI. A response to the concern was written that attempted to justify why it was unnecessary to take corrective action to remove a component from alert status. The response stated that evaluations have not been performed each and every time the normal frequencies of testing are resumed after a component had been in alert. The response further made the assumption that, if the test results on the most recent test was acceptable, then the previous alert test results were either due to instrument inaccuracies or variances in operator/test engineer test techniques. The response concluded by stating that, since the second test results were acceptable, it demonstrated that increased monitoring was not warranted since a failure trend was not indicated. The inspectors did not consider that to be a valid conclusion.

7.2 Conclusions

A violation was identified for failure of the licensee to take corrective action prior to restoring pumps and valves from an alert status as required by ASME Code Section XI.

8 FOLLOWUP (92701)

8.1 Verification of Plant Staff Qualifications

The inspectors selected, on a sampling basis, recently appointed managers at the River Bend Station for review to verify that their qualifications met the requirements of TS 6.3, "Unit Staff Qualifications." This was a followup on the violation identified in NRC Inspection Report 50-458/93-12, where the replacement radiation protection manager did not meet these requirements. The following managers were evaluated.

8.1.1 Plant Manager

The inspectors reviewed the Plant Manager's resume of employment and experience, compared with ANSI/ANS 3.1-1978, "For Selection and Training of Nuclear Power Plant Personnel," as implemented by TS 6.3. ANSI/ANS 3.1-1978 required the Plant Manager to have acquired the experience and equivalent training normally required to be eligible for a senior reactor operator's (SRO) license whether or not the examination was taken. The Plant Manager did not meet this requirement for the River Bend Station plant type (General Electric Boiling Water Reactor); however, he held an SRO license at a Westinghouse Pressurized Water Reactor in 1976, and was a Plant Manager at that plant type from 1990 to 1993.

ANSI/ANS 3.1-1978 does not require the Plant Manager to have SRO training, provided his designated principal alternate meets the nuclear power plant experience and training requirements for the plant manager. The APM, Operations and Radwaste met those requirements and, therefore, the Plant Manager's qualifications were acceptable. In addition, the Plant Manager informed the inspectors that he intended to obtain plant-specific SRO training in the future.

8.1.2 APM, Maintenance

Based on the inspector's review of the resume of employment and experience provided by the licensee for the APM, Maintenance, the individual met the qualifications requirements of TS 6.3.

8.1.3 Manager-Engineering/System Engineering

ANSI/ANS 3.1-1978 requires the individual holding this position to have 8 years of experience in responsible positions related to power generation, of which 3 years shall be nuclear power plant experience. The manager at River Bend Station was found to have a Baccalaureate Degree in Civil Engineering, a Master's Degree in Business Administration, and more than 18 years nuclear power plant experience consisting of construction engineering, technical services, planning and scheduling, maintenance management, and plant modifications. This individual met and exceeded the minimum qualification requirements.

8.1.4 Manager-SAQV

ANSI/ANS 3.1-1978 did not address the qualifications for this specific position, other than the general requirement that nuclear power plant personnel shall have a combination of education, experience, health, and skills commensurate with their functional level of responsibility. However, the USAR, Revision 6, Chapter 17, provides the licensee's commitment for the qualifications of the Manager-SAQV. The inspectors compared this information with the resume provided by the licensee pertaining to the individual holding this position and then interviewed the Manager-SAQV to obtain clarification of the resume. Later, the licensee developed, and submitted to the inspectors, an evaluation comparing the individual's background and experience with the USAR. There was no 10 CFR 50.59 or other formal evaluation completed prior to this inspection, according to the licensee.

Section 17.2.1.2.4.1 of the USAR requires, as a minimum, that the Manager-SAQV be a graduate of a college or university with a Baccalaureate Degree in engineering, a science, a related field, or equivalent capabilities. The Manager-SAQV did not hold a degree, but attended nearly 4 years of college, studying business and engineering technology, and was working toward a degree in psychology. He considered himself to have equivalent capabilities based on various past experience in nuclear power plant management positions. For example, he chaired a Quality Assurance (QA) Subcommittee, developed and implemented self-assessments, and was involved in the identification of problems and their corrective actions as part of the NRC's Diagnostic Evaluation Team inspection at Arkansas Nuclear One. He was a member of the offsite safety review boards at Fort Calhoun Station and Arkansas Nuclear One, and participated in audits. Overall, the inspectors found that, although the Manager-SAQV did not hold a college degree, he demonstrated equivalent capabilities by holding positions in the past 10 years that would normally be held by individuals with a degree.

Section 17.2.1.2.4.2 requires a minimum of 4 years in QA or a QA-related activity, with at least 2 of those years in the nuclear power industry as a manager or supervisor. The licensee's evaluation of this USAR commitment against the individual's actual background and experience provided a number of instances where he participated in QA-related activities. The Manager-SAQV appeared to have a background that was commensurate with his licensing and safety assessment responsibilities, but was marginal in specific QA organizational experience and training.

Sections 17.2.1.2.4.3, -4, -5, -6, -7, and -8 refer to less specific requirements and, thus, relate to the individual's demonstrated management skills and ability to maintain a good working relationship with the various organizations he would interface with. The licensee's evaluation showed that the Manager-SAQV met or exceeded those requirements.

8.1.5 Conclusions

The inspectors concluded that all of the new managers reviewed had met or exceeded the minimum qualifications of ANSI/ANS 3.1-1978, as implemented by TS 6.3. The inspectors also concluded that the Manager-SAQV met the qualification requirements in USAR Section 17.2.1.2.4, based on review of the licensee's evaluation submitted, an interview with the individual, and observation of his performance since he was appointed in September 1993.

8.2 Quality Concern Program (QCP)

The inspectors conducted a review of the licensee's QCP in August 1993, as documented in NRC Inspection Report 50-458/93-26, Section 4. While the review was an information gathering process in the absence of NRC guidance as to what constitutes an appropriate employee concern program, discussion over the inspectors' review at the September 30, 1993, exit meeting prompted the Vice President-Operations to indicate that the licensee was evaluating the QCP at River Bend Station.

8.2.1 Development of New QCP at River Bend Station

During this inspection period, the inspectors were informed that Entergy Operations, Inc. (EOI) was in the process of having independent contractor (Synergy Corp.) evaluations performed at all EOI sites. The purpose of the evaluation was, in part, to establish a consensus on philosophy and programmatic framework for EOI employee concern programs.

At River Bend Station, the licensee implemented plans to improve the QCP by elevating the program reporting chain such that objectivity and protection of the privacy of concerned individuals would be better assured by revising the applicable procedures and communicating the changes to the staff. A new QCP coordinator was appointed. This individual was the Supervisor, Performance Assessment, and reported directly to the Manager-SAQV.

As of the end of this inspection period, the licensee had accomplished the following actions toward developing a new QCP:

- An employee survey was performed to understand the perceptions and attitudes about the existing QCP and to characterize the overall climate for identifying and resolving potential nuclear safety and quality concerns.
- Preliminary themes were developed from the survey data.
- A workshop was held to validate the above survey themes and establish customer requirements and recommendations.
- A Quality Action Team was formed, which: (1) developed a new process flow chart, (2) established QCP performance measures, (3) developed short- and long-term action plans for new program implementation, and (4) identified training and communication issues.

The licensee was in the process of developing a QCP that would be standard throughout EOI plants and would provide high QCP Coordinator and program visibility. This effort was focused on encouraging concerned employees to identify safety concerns without fear of retribution.

8.2.2 Conclusions

The inspectors concluded that the licensee was working toward developing a good employee concerns program that will be a significant improvement over the existing program.

9 ONSITE REVIEW OF LICENSEE EVENT REPORTS (LERs) (92700)

9.1 (Closed) LER 458/92-021: Unidentified Leak Rate Inaccurately Determined for 6 Days Following Overflow of the Drywell Pedestal Floor Drain Sump

While operating the plant at power, both drywell pedestal floor drain sump pumps malfunctioned. This caused the sump level to slowly, but continuously, increase. Sump level was used to monitor unidentified reactor coolant leakage in accordance with TSs 3.4.3.1 and 3.4.3.2. For 6 days the sump was in an overflow condition which changed the calculation for leak rate; however, the operators and support personnel were unaware of it because of difficulties in interpreting the construction drawings. After review, it was determined that the properly calculated leak rate did not exceed the TS limit.

Corrective actions included revising the system operating procedure to manually calculate leak rate until the plant could be shut down. Subsequently, the pumps were repaired and satisfactorily tested. The alarm response procedure was revised accordingly, and the Loop Calibration Report was revised to provide information on the correct sump overflow level. The inspectors reviewed the

revised procedure and noted that the pumps have performed well for the remainder of the fuel cycle. The licensee's actions were appropriate on this issue.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

R. E. Barnes, Supervisor, ASME/ISI
J. B. Blakely, Director, Predictive Programs
*O. P. Bulich, Director, Licensing
*D. R. Clymer, Senior Human Performance Engineer
*R. E. Cole, Supervisor, Control Process Systems
*W. L. Curran, Cajun Site Representative
L. L. Dietrich, Supervisor, Nuclear Licensing
*J. R. Douet, Director, Plant Projects & Support
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
*J. R. Hamilton, Manager-Engineering
*W. C. Hardy, Radiation Protection Supervisor
*J. Holmes, Director, Chemistry
*H. B. Hutchens, Director, Nuclear Station Security
R. T. Kelly, Instrument and Controls Supervisor
G. R. Kimmell, General Maintenance Supervisor
*M. A. Krupa, Assistant Plant Manager, System Engineering
J. W. Leavines, Supervisor, Nuclear Safety Assessment Group
*T. R. Leonard, Manager, Engineering/System Engineering
*D. N. Lorfing, Supervisor, Nuclear Licensing
R. C. Lundholm, Supervisor, Mechanical Process Systems
I. M. Malik, Supervisor, Corrective Action & Reviews
C. R. Maxson, Supervisor, Performance Assessment Group
*R. M. McAdams, Senior Licensing Engineer
J. R. McGaha, Vice President, River Bend Nuclear Group
*J. H. McQuirter, Senior Licensing Analyst
J. F. Mead, Supervisor, Control Systems
W. H. Odell, Director, Radiological Programs
C. R. Coats, Electrical Maintenance Supervisor
*J. P. Schippert, Technical Assistant
*M. B. Sellman, Plant Manager
B. R. Smith, Mechanical Maintenance Supervisor
M. A. Stein, Director, Plant Engineering
*K. E. Suhrke, Manager, Site Support
W. J. Trudell, Assistant Operations Supervisor
*J. E. Venable, Assistant Plant Manager, Operations & Radwaste
*D. H. Williamson, Senior Nuclear Engineering Technologist
G. S. Young, Supervisor, Reactor Engineering
*K. F. Zimmermann, Senior Nuclear Communications Specialist
*G. A. Zinke, Technical Coordinator, Safety Assessment & Quality Verification

* 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 March 16, 1994. 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

1 DOCUMENTS REVIEWED

1.1 Procedures Related to New Fuel Receipt (Section 6)

QCI-3.1, "Receiving Inspection of Nuclear Fuel," Revision 5

QCI-3.5, "Receiving Inspection of Nuclear Fuel Channel/Channel Fasteners," Revision 4

REP-0002, "New Fuel Unpacking and Handling," Revision 5

REP-0003, "Fuel Channeling in the Fuel Inspection Stand," Revision 4

REP-0005, "New Fuel Receipt," Revision 3

REP-0010, "Special Nuclear Material (SNM) Movement and control Accounting," Revision 9

REP-0012, "Criticality Rules," Revision 1

GMP-0104, "Inspection and Assembly of New Fuel," Revision 0