ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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License No.:	NPF-47
Report No.:	50-458/97-14
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana 70775
Dates:	August 31 through October 11, 1997
Inspectors:	W. F. Smith, Senior Resident Inspector D. L. Proulx, Resident Inspector M. P. Shannon, Project Engineer L. E. Ellershaw, Reactor Inspector, Maintenance Branch, Division of Reactor Safety
Approved By:	Elmo E. Collins, Chief, Project Branch C
Attachment:	Supplemental Information

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EXECUTIVE SUMMARY

River Bend Station
NRC Inspection Report 50-458/97-14

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The performance of plant operators was professional and reflected a focus on safety as the plant coasted down on the approach to Refueling Outage 7. The normal shutdown on September 11 and 12, 1997, was well executed and error free (Section O1.1).

- Refueling Outage 7 refueling operations were consistently performed in a formal manner in accordance with procedures, which resulted in an error-free refueling. This was an improvement over the previous refueling in which errors were noted (Section O1.2).

- The licensee's suppression pool cleanup actions resulted in a significant improvement in overall pool cleanliness. The new pool cleanup system should reduce future sludge accumulation. Approximately 80 percent of the sludge was left in the weir wall area of the pool inside the drywell. However, based on emergency core cooling system (ECCS) strainer test data, the inspectors concluded that the suppression pool was sufficiently clean for startup and power operation in Fuel Cycle 8 (Section O2.1).

Maintenance

- The licensee completed installation of newly designed ECCS suction strainers. The installation and postmodification testing of the new strainers was well executed considering the difficulties associated with working under water (Section M1.1).

- The Division II emergency diesel generator (EDG) maintenance outage was properly performed in accordance with station procedures. The licensee's investigation and resolution of the cracked valve adjusting screw swivel pads (VASASPs) was thorough (Section M1.2).

- The replacement of reactor head vent Valve B21-MOVF002 was well executed. Work planning and execution kept radiation exposures as low as reasonably achievable (ALARA) (Section M1.3).

- Surveillance and postmodification testing observed during this inspection period, including significant end-of-outage testing, was properly conducted in accordance with regulatory requirements (Section M1.4).

- Test engineers applied weak testing practices by failing to configure a local leak rate test manifold to prevent leakage between the pressure source and the test boundary. While this lineup did not actually affect test results, it presented the potential to introduce nonconservative results (Section M1.5).

- During the conduct of control rod scram timing tests, the licensee identified that an existing half scram signal invalidated test results. The test procedure did not establish the requisite conditions for the test (Section M1.6).

- Improvements to material condition which were implemented in Refueling Outage 7 included a suppression pool cleanup system, cleaning of the suppression pool, upgraded ECCS suction strainers, cleaning of Division II residual heat removal (RHR) heat exchangers, repairing approximately 150 valves, replacing recirculation pump seals, and overhaul of Reactor Feedwater Pumps A and C. No cracks were found in the reactor core shroud (Section M2.1).

Engineering

- The licensee's actions in response to degraded capacity of the Division II RHR heat exchangers were appropriate to the circumstances and corrective actions were well executed (Section E2.2).

- The licensee's evaluation of the short-duration overload of the Division II Transamerica DeLaval EDG was comprehensive and thorough. The licensee's bases for determining the crankshaft inspection requirements were appropriate (Section E2.3).

Plant Support

- Housekeeping was very good due to strong day-to-day management support throughout Refueling Outage 7 (Section O1.1).

- Problems were identified involving the failure to properly maintain high radiation area (HRA) barriers. The licensee's corrective actions were effective in preventing further problems (Section R1.1).

- There were two incidents where locked high radiation area (LHRA) barriers were not properly controlled because of inattention to radiation protection (RP) requirements. One of these incidents could have been prevented if timely corrective actions had been implemented subsequent to a similar incident in November 1996 (Section R1.2).

- The licensee demonstrated excellent performance in reducing radiation exposures ALARA. Even with an expanded work scope and an extended outage duration, radiation exposures were less than goal (Section R1.3).

- The security department's preparations for opening the temporary protected area may not have been thorough, in that they failed to identify a darkened area underneath a wooden porch; however, the response to this issue was timely and proper (Section S1.2).

Report Details

Summary of Plant Status

At the beginning of this inspection period, the plant was operating at approximately 92 percent power and was coasting down as Refueling Outage 7 approached. On September 12, 1997, the reactor was shut down and placed in Mode 4 (cold shutdown) to commence the refueling outage. The plant entered Mode 5 (refueling) on September 13 and remained in Mode 5 until October 5 when the reactor head fasteners were tensioned signifying re-entry into Mode 4. The plant remained in Mode 4 until the end of the inspection period.

On September 13, while the plant was in Mode 4, shutdown cooling was secured to accommodate a test of the new alternate decay heat removal portion of the suppression pool cleanup system. During this test, the plant inadvertently heated up and transitioned to Mode 3 (hot shutdown) for approximately 30 minutes, while conditions required by the Technical Specification (TS) for Mode 3 were not met. This issue, combined with a 17-minute loss of shutdown cooling that occurred on October 4, was discussed in detail in NRC Special Inspection Report 50-458/97-015.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations including control room observations, attendance at plan-of-the-day meetings, and plant tours. In general, the performance of plant operators was professional and reflected a focus on safety as the plant coasted down to Refueling Outage 7. Three-way communications were frequently utilized and operator response to alarms were observed to be prompt and appropriate to the circumstances. The shutdown on September 11 and 12 from 88 percent power was well executed and error free.

Housekeeping before and during the refueling outage was appropriate to the circumstances. However, during tours in both the auxiliary and turbine buildings, the inspectors found a number of areas where tools, electrical extension cords and general clutter were laying around in areas not being actively worked. The fuel and reactor buildings were in good condition. Minor discrepancies identified by the inspectors were promptly corrected. Licensee management placed emphasis on managers touring the plant to keep housekeeping under strong controls. Each day a different manager reported his findings to the general plant manager, operations, and his staff at the plan-of-the-day meetings. These actions appeared to have a positive effect on plant cleanliness.

O1.2 Refueling Activities

a. Inspection Scope (60710)

The inspectors observed refueling operations from September 22 through 26, 1997. These observations included evaluating the licensee's procedure adherence and foreign material controls.

b. Observations and Findings

The inspectors observed the refueling crew using self-checking and peer-checking techniques to conduct refueling operations. The bridge operators consistently used three-way communications while moving fuel. The licensee followed good foreign material controls during this evolution and no debris was unintentionally dropped into the reactor cavity. The inspectors noted that quality assurance personnel were frequently monitoring refueling activities. Quality assurance personnel identified minor issues that were appropriately dispositioned via the condition reporting process. In addition, licensee management monitored the refueling activities to ensure that requirements were met. Following completion of core alterations, the licensee performed a full core verification. No errors were identified during this verification.

c. Conclusions

Refueling operations were consistently performed in a formal manner in accordance with procedures, which resulted in an error-free refueling. This was an improvement over the previous refueling in which errors were noted.

O2 Operational Status of Facilities and Equipment

O2.1 Review of Suppression Pool Cleanup Activity

a. Inspection Scope (71707)

The inspectors evaluated the licensee's actions pertaining to suppression pool cleanliness to ensure that there was no foreign material present that could clog the ECCS suction strainers during a design basis loss of coolant accident.

b. Observations and Findings

The licensee engaged the services of divers to clean the suppression pool near the end of the refueling outage. The inspectors observed video tapes of this activity and noted that the stainless steel surfaces of the pool outside of the drywell were clearly visible and had been vacuumed to remove all sludge. Foreign objects were removed, which comprised mainly of scaffold knuckles, pens, small fasteners, and tie wraps. None of the objects appeared to have had any effect on the past fuel cycle operability of the ECCS suction strainers.

The inspectors noted that, although the vent portals in the drywell wall appeared to be clean, the bottom of the weir wall area in the drywell had a layer of soft, wet sludge with an approximate thickness of 1 inch. The licensee explained that approximately 80 percent of the sludge in the weir wall region was left in place. The window of opportunity during Refueling Outage 7 had expired before the licensee could complete the cleaning process because of delays installing the new ECCS strainers and breakdowns of vacuuming equipment. Based on the previous accumulation rate experienced, the licensee estimated that no more than 300 pounds of sludge would accumulate in the suppression pool over the next fuel cycle. The licensee produced correspondence and test data from General Electric that indicated that, with the design maximum of 633 cubic feet of fibrous insulation dislodged from the drywell and up to 10,000 pounds of sludge, there was sufficient margin for strainer differential pressure. The presence of sludge had minimal effect on the new ECCS strainers. Therefore, it was acceptable to leave a small amount of sludge in the suppression pool. The inspectors noted that, with the new suppression pool cleanup system in service, further accumulations of sludge should be reduced.

c. Conclusions

The licensee's actions resulted in a significant improvement in overall suppression pool cleanliness. The new suppression pool cleanup system should reduce future sludge accumulation. Approximately 80 percent of the sludge was left in the weir wall area of the pool inside the drywell. However, based on ECCS strainer test data, the inspectors concluded that the suppression pool was sufficiently clean for startup and power operation in Fuel Cycle 8.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Installation of ECCS Suction Strainers

a. Inspection Scope (62707)

Between September 16 and 19, 1997, the inspectors observed portions of the installation of new higher capacity suppression pool suction strainers for low pressure core spray and high pressure core spray in accordance with MAIs 311138 and 311136, respectively.

b. Observations and Findings

This work activity involved removal of the original ECCS strainers and installation of a foundation to support the outboard end of the new General Electric stacked disk type strainers. The base plates for the strainer supports were fitted and welded in place. The strainer was then bolted up to the pipe flange and the strainer support welded and bolted in place. All of this work was performed by divers underwater in the suppression pool. Visibility was good and the inspectors viewed the work on a video monitor.

The MAI instructions were followed by the diving coordinator who signed off each step as it was performed. The divers appeared to be well briefed and knowledgeable of the tasks to be undertaken. The diving coordinator and the divers performed as a team in a professional and orderly manner under the supervision of River Bend management's staff.

Each of the new low pressure ECCS strainers was tested with a 2-hour run of the respective ECCS pumps utilizing the appropriate inservice testing surveillance test procedure. In addition to the pump vibration data, which was normally taken during inservice testing, vibration readings were obtained from the suction piping adjacent to the containment penetration to ensure that there was no abnormal vibration set up by the new strainer configuration. The inspectors reviewed the completed data and found that the new strainers improved the net positive suction head; however, there was not enough difference to affect the inservice reference data. As such, it was not necessary to establish new baseline inservice test data as permitted by ASME Code, Section XI. The high pressure core spray pump suction strainer was tested by obtaining pressure and vibration data in accordance with MAI 311136 while running the pump for 2 hours in accordance with the system operating procedure. The inservice test procedure could not be utilized because the pump took suction from the condensate storage tank during inservice testing. The system operating procedure provided direction to take suction via the suppression pool strainer. The postmodification test results were satisfactory.

c. Conclusions

The licensee completed installation of newly designed ECCS suction strainers. The installation and postmodification testing of the new strainers was well executed considering the difficulties associated with working underwater.

M1.2 Division II EDG Maintenance

a. Inspection Scope (62707, 37551)

The inspectors witnessed performance of MAIs P594128 and ME03304-03 associated with the Division II EDG. This MAI involved inspection, cleaning and reinstallation of the fuel injectors, inspection of the cylinder subcovers, and inspection and replacement of the VASASPs for the Division II EDG. The inspectors also evaluated the licensee's response to the identification of cracked VASASPs.

b. Observations and Findings

On September 28-29, 1997, the inspectors witnessed the inspection and cleaning of the Division II EDG fuel injectors. The inspectors noted that the mechanics used good self-checking techniques and carefully performed the task in accordance with the MAI.

On September 29, the inspectors observed the inspections of the Division II EDG cylinder subcovers. The licensee identified cracking in three of eight subcovers on one of the load bearing bolt holes. The licensee initiated Condition Report 97-1647 to enter this item into the corrective action system. The vendor supplied new subcovers with strengthened bolt holes and reinstalled them on the Division II EDG. The inspectors concluded that these tasks were completed satisfactorily.

Earlier on September 15, during inspection of the Division I EDG, the licensee identified that one of the four VASASPs for the Cylinder 5 was cracked. The licensee initiated Condition Report 97-1647 and performed an initial operability assessment. The system engineer's initial operability assessment stated that this cracked VASASP would likely remain in place and would not affect the ability of Division I EDG to meet its intended safety function. Therefore, the operability of the Division II EDG was not questioned at this time. The cracked VASASP was replaced and the Division I EDG outage work was completed.

However, on September 26, the licensee performed the postmaintenance run of the Division I EDG and identified two additional cracked VASASPs. Cylinders 7 and 8 had cracks in one of four VASASPs. The licensee identified that all of the VASASPs (64 total) for Division I and II EDGs were procured from the same lot number (VV64). The licensee performed a metallurgical analysis of the cracked VASASP for the Cylinder 5 of the Division I EDG and determined that the VASASP was of an incorrect material composition. In addition, the licensee noted that the ball of the VASASP contained a machined edge that impeded proper movement of the swivel pad. The metallurgical analysis determined that the VASASP was composed of American Iron and Steel Institute (AISI) 8660 steel while the vendor information indicated that the proper material was AISI 8620. AISI 8660 steel is a brittle alloy steel and more susceptible to cracking.

Based on this information, the licensee's operability assessment was revised. The licensee noted that, with the existence of the cracked VASASPs and the potential for the formation of additional cracking due to the incorrect material, the EDG would likely start and run; but the licensee did not have reasonable assurance that the EDG would run for 30 days per the design basis. Therefore, the licensee declared the Division I EDG inoperable. In addition, the licensee concluded that, because the VASASPs for the Division II EDG were from the same lot number as the cracked

VASASPs of the Division I EDG, the Division II EDG was susceptible to the same failure mode. Therefore, at 5:22 p.m. on September 26, the licensee declared the Division II EDG inoperable. The licensee suspended core alterations as required by the TSs and reported this event to the NRC Operations Center per 10 CFR 50.72(b)(2)(iii)(D).

The licensee procured 65 new VASASPs from the vendor. The new VASASPs were of Lot PP56 and were not susceptible to the same failure as Lot VV64. The licensee performed a metallurgical analysis of the one extra VASASP from Lot PP56 and found that its material properties were consistent with those of AISI 8620 steel. The licensee replaced all 32 VASASPs on the Division I EDG, performed the applicable TS surveillances, and declared the Division I EDG operable on September 27 at 3:44 p.m. After the Division I EDG was restored to operable status, the licensee commenced the Division II EDG outage. Upon inspection of the VASASPs for the Division II EDG on September 28, the licensee identified cracks on VASASPs for the Cylinders 1, 2, 4, 5, and 8. A total of 10 of the 64 VASASPs between the two EDGs were cracked. The inspectors examined the cracked VASASPs and noted that the VASASPs contained thru-wall cracks. Most of the cracks were 180° in circumference although two of the VASASPs were cracked such that small pieces of the swivel pads were missing. The inspectors witnessed the replacement of the VASASPs for the Division II EDG, which was performed with no problems.

The licensee took action to address the generic implications of this problem by determining from the vendor where else Lot VV64 VASASPs were installed. The vendor stated that the only other nuclear station that received these VASASPs was Catawba. The Catawba system engineer responsible for the EDGs was contacted and he reported that they were in their warehouse and not installed in the EDGs. A Nuclear Network Bulletin was issued on October 1 alerting the industry to this problem.

The licensee's investigation revealed that the vendor procured the VASASPs for Lot VV64 from a subcontractor. The vendor had noted the above material and manufacturing deficiencies but evaluated these problems as inconsequential. For corrective action associated with Condition Report 97-1647, the licensee assigned the Entergy Operations, Inc. material requirements department to take appropriate actions to verify that the vendor took effective corrective actions for the nonconformances and generic implications discussed above by April 30, 1998. The inspectors will evaluate the licensee's closure of Condition Report 97-1647 during review of Licensee Event Report 97-007.

c. Conclusions

The Division II EDG maintenance was performed well and in accordance with procedures. The licensee's investigation and resolution of the cracked VASASPs in the EDGs was thorough and corrected the problem.

M1.3 Replacement of Reactor Vessel Head Vent Valve

a. Inspection Scope (62707)

On October 11 and 12, 1997, the inspectors observed portions of work activities associated with the replacement of Valve B21-MOVF002 covered by MAI 304462.

b. Observations and Findings

The inspectors found the work performed to be professional and thorough. Maintenance technicians demonstrated good foreign material exclusion practices and good attention to detail by following the work instructions and peer checking. The technicians were experienced and knowledgeable of their assigned tasks. Appropriate clearances were utilized for personnel and equipment safety, and the operators entered the correct TSs limiting conditions for operation.

The inspectors found that all personnel involved in this work wore the proper industry safety equipment (face shields for grinding). High efficiency particulate air filtered ventilation was appropriately used and positioned during work on contaminated surfaces. Supervision and engineering personnel were appropriately involved in monitoring and providing guidance to the workers during this task. Difficulty was encountered in gaining access for one of the welds, which resulted in unsatisfactory radiography results. The licensee disconnected the mechanical joints and moved the assembly to the hot machine shop. This action facilitated good welds with satisfactory radiography results and kept radiation exposures ALARA.

The inspectors observed the setup for radiography of the valve welds and verified that the radiological controls and boundaries for the work were appropriate. No problems were identified by the inspectors.

c. Conclusions

The inspectors concluded that the replacement of reactor head vent Valve B21-MOVF002 was well executed. Work planning and execution kept radiation exposures ALARA.

M1.4 Surveillance and Modification Testing Observations

a. Inspection Scope (61726)

The inspectors observed all or portions of the following test procedures during this inspection period:

- Postmodification Test 91-0074-PMT-03, Revision 4, "Functional Check of the Division II EDG Synchronization Check Device," performed on October 7, 1997.

- Surveillance Test Procedure STP-309-0614, Revision 7A, "10-Year Simultaneous Start of Divisions I, I, and III EDGs," performed on October 9, 1997.
- Surveillance Test Procedure STP-050-0702, Revision 01, "Refueling Outage Reactor Pressure Vessel Inservice Leakage Test," performed on October 11, 1997.

b. Observations and Findings

The inspectors found that the surveillance tests listed above were conducted properly such that meaningful results were obtained. Self-checking and peer-checking were evident when it was appropriate to do so. During independent verification, the verifiers demonstrated a conscious effort to maintain independence from the performers. TS limiting conditions for operation were entered when required. Measuring and test equipment was verified to have been in calibration. The inspectors reviewed the completed test documentation and noted that it was legible and all acceptance criteria were met.

c. Conclusions

In general, surveillance and postmodification testing observed during this inspection period was conducted properly and in accordance with regulatory requirements.

M1.5 Local Leak Rate Testing of Main Steam Isolation Valves (MSIV)

a. Inspection Scope (61726)

The inspectors observed portions of the local leak rate testing of the inboard and outboard MSIV A in accordance with Surveillance Test Procedure STP-208-3601, Revision 3, "Inboard and Outboard Main Steam Isolation Valves and Outboard Drain Valve 'A' Steam Line Leak Rate Test."

b. Observations and Findings

On September 17, 1997, the inspectors observed the test of Main Steam Line A between the inboard and outboard MSIVs. The inspectors noted that the cross-connect tubing between the air source and the test boundary, used to initially pressurize the test boundary, did not have a vent valve to enable the test engineer to isolate and vent the section of tubing to atmosphere. As a result, there was a potential undetected leakage path between the pressure source and the test boundary. This could have caused nonconservative test results. The inspectors questioned this condition and the test engineer responded by acknowledging the concern and altering the manifold to provide a vent valve in between the cross-connect tubing isolation valves.

The inspectors questioned the validity of testing already completed. The licensee responded that this was a unique test manifold and others were constructed with a suitable vent that was appropriately used. To resolve the question pertaining to the MSIV test manifold, the test engineer performed a tightness test on the crossover isolation valves and found no leakage. This provided reasonable assurance that the previous tests were valid.

The inspectors reviewed Surveillance Test Procedure STP-208-3601 and noted that there was no direction in the procedure to ensure that the test manifold was properly configured. The licensee stated that use of the manifold was within the skill of the craft, and this was an isolated case where the test engineer overlooked the need for a vent path as described above. The inspectors acknowledged that the test engineer immediately recognized his error when the inspectors identified the deficiency; however, this was considered a poor testing practice that could have resulted in an invalid test. The licensee acknowledged the inspectors comment.

c. Conclusions

Test engineers applied weak testing practices by failing to configure a local leak rate test manifold to prevent leakage between the pressure source and the test boundary. While this line up did not actually affect test results, it presented the potential for nonconservative results.

M1.6 Control Rod Scram Timing Test

a. Inspection Scope (61726, 37551)

The inspectors observed portions of the reactor control rod scram timing test conducted in accordance with Surveillance Test Procedure STP-052-3701, Revision 12, "Control Rod Scram Testing."

b. Observations and Findings

On October 12, 1997, the inspectors observed portions of the control rod scram timing test. The test was performed in a deliberate, well-controlled manner. The personnel participating in the test utilized good three-way communications.

During the test, the reactor engineer noted that on some control rods the recorder chart indicated the time of the first notch occurred before the initiation signal. All other data indicated normal performance of the rods. The system engineer was consulted, and there were no deficiencies identified with the rod control and indication system. Having decided that this was an anomaly with the recorder, the test was continued to near completion on the basis that those rods would have to be retested. When the reactor engineering manager arrived to check on the status and performance of the test, the anomaly was brought to his attention. Knowing that the first notch must not precede the initiation signal, plant conditions were reviewed. During this review, the licensee identified that there was an existing half scram signal in the reactor protection system because of work on the nuclear instruments. With a half scram, one of the two scram pilot solenoid valves was already de-energized. This invalidated the test results because the individual rod scram test switches were connected in series for the initiation signal, and each switch independently opened its respective scram pilot solenoid valve. With one solenoid valve already open, the control rod would be set in motion before the second test switch was actuated.

The licensee initiated Condition Report 97-1816 and determined that the test was invalid; however, the testing accomplished provided confidence that there were no other problems with the control rods for startup. The licensee scheduled a repeat of the test prior to exceeding 40 percent power as permitted by the TS. The reactor engineers were counseled on the proper performance of this test. The licensee identified that Procedure STP-052-3701 did not contain any precautions or prerequisites that addressed any requirement to not have scram signals present during the test. The licensee indicated plans to revise the procedure to address this requirement. Failure to maintain Procedure STP-052-3701 adequate to ensure that the correct plant conditions exist to properly conduct the scram timing test is a violation of TS 5.4.1.a. However, this nonrepetitive, licensee-identified and corrected violation is being treated as a noncited violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy (50-458/9714-01).

c. Conclusions

During the conduct of control rod scram timing tests, the licensee identified that an existing half scram signal invalidated test results. The test procedure did not establish the requisite conditions for the test. An NCV was identified for failure to maintain procedures adequate to ensure that the correct plant conditions exist to properly conduct control rod scram time testing.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 General Comments on Plant Materials Condition

Inspectors noted the following improvements which were made to plant material condition:

- A suppression pool cleanup system was installed and tested satisfactorily. River Bend was not originally designed to have a suppression pool cleanup system. The addition of this system is expected to significantly improve suppression pool water quality. Also, significant suppression pool clean up activities were completed (See Section O2.1).

- ECCS suction strainers were upgraded (see Section M1.1).

- The reactor core shroud inspection was satisfactory, i.e., no cracks were found (see Section E2.1).
- The Division II RHR heat exchangers were chemically cleaned, restoring the design heat transfer capability (see Section E2.2).
- Approximately 150 valves were repaired, including the previously leaking service water/standby service water interface valves.
- Both the reactor recirculating pump shaft seals were replaced.
- Extensive overhaul work and balancing was accomplished on Reactor Feedwater Pumps A and C.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Core Shroud Weld Inspection

a. Inspection Scope (37551)

The inspectors reviewed the licensees actions in response to ultrasonic testing indications found on the reactor core shroud welds.

b. Observations and Findings

On September 19, 1997, the licensee was in the process of inspecting the reactor core shroud pursuant to NRC Generic Letter 94-03, "Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors." The inspectors were informed by the licensee that indications were detected at Welds H6A and H4 using a 45° shear-wave probe. This was unexpected because the metallurgical properties of the River Bend shroud and the combination of conditions at River Bend that influenced the shroud's susceptibility to intergranular stress corrosion cracking were well below the threshold of those experienced at facilities which have identified cracks. The results using 60° longitudinal wave probes were negative. Industry experience indicated that actual cracking produced strong and clear responses when examined using the 60° probes.

To resolve the indications, General Electric performed manual ultrasonic examinations of Welds H6A and H4 in the unused Unit 2 shroud. The examinations were performed using probes identical to those that were used on the Unit 1 shroud. The instrument delay, range, and gain settings were adjusted to provide the same screen display and sensitivity as was present in the Unit 1 data. The 45° shear-wave responses obtained from the Unit 2 shroud matched those recorded from the Unit 1 shroud. The 60° beam produced essentially no response from the weld area.

General Electric's Level III examiner concluded that the 45° shear-wave responses that were present in the Unit 1 shroud were not related to defects but were unusually strong, though benign, reflections of the weld fusion line. This better explained the uniformity of the depth of the indications over the entire length of the accessible welds.

On September 21, the licensee obtained an independent review of the General Electric resolution from the Electric Power Research Institute Nondestructive Examination Center which concurred with the General Electric disposition.

On September 25, the licensee, NRC Region IV, and NRC Headquarters technical experts met on a teleconference to discuss the matter; and all questions were answered to the satisfaction of the NRC representatives.

c. Conclusions

The licensee resolved the reactor core shroud weld ultrasonic indications in an excellent manner.

E2.2 Fouling of Shutdown Cooling Heat Exchangers

a. Inspection Scope (37551)

The inspectors reviewed the licensee's actions in response to Division II RHR heat exchanger low heat transfer test results.

b. Observations and Findings

On September 12, 1997, the licensee conducted a performance test on Division II RHR Heat Exchangers B and D pursuant to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The test was performed using Plant Engineering Procedure PEP-0240, Revision 1, "Performance Monitoring Program for the Residual Heat Removal Heat Exchangers E12-EB001B and E12-EB001D (Div II)," to verify the heat transfer capability of the RHR heat exchangers. The test results showed that the heat transfer capability of the Division II RHR heat exchangers was 121.8×10^6 Btu/hr, which was less than the design minimum requirement of 126.4×10^6 Btu/hr. The Division I RHR Heat Exchangers A and C test results showed a heat transfer capability of 136.1×10^6 Btu/hr. The licensee initiated Condition Report 97-1451 on September 16. The licensee's operability assessment determined that the heat exchangers were operable for shutdown cooling in Modes 4 and 5 for the remainder of Refueling Outage 7; however, they were considered inoperable for suppression pool cooling in Modes 1, 2, or 3.

The inspectors reviewed previous Division I and II RHR heat exchanger test data. The Division II RHR heat exchangers had been tested once previously during Refueling Outage 6 (January 1996), and those test results showed a heat transfer capability of 128.3×10^6 Btu/hr. The Division I RHR heat exchangers had been tested during Refueling Outage 5 and Refueling Outage 6 with the results being 139.1×10^6 Btu/hr and 139.5×10^6 Btu/hr, respectively.

The licensee formed a significant event response team to evaluate the heat exchanger test results. Since many heat exchanger problems can be traced to the service water (tube side), the initial review effort focused on the heat exchanger tubes, which were fabricated from a 70/30 copper-nickel alloy. Visual examination revealed that the inside diameter of the tubes exhibited some fouling but not to the extent that would have been expected based on the test results. A boroscope inspection was performed in the shell side of Heat Exchanger B. The tubes appeared to be covered with a uniform layer of material. Samples of the material were sent to a laboratory, which determined that approximately 8 percent was organic and approximately 66 percent was iron oxide, by weight. Examination of a sample from the Division I RHR heat exchangers revealed that the organic composition was nearly 40 percent less by weight than the Division II RHR heat exchangers, while the iron oxide content was virtually the same. The significant event response team concluded that the shell side of the Division II RHR heat exchangers required cleaning. The decision was also made that, since the test results for the Division I RHR heat exchangers were acceptable and their tube sides had been hydrolazed and inspected during this outage, they would not undergo a chemical cleaning of the shell side at this time.

The inspectors learned that the main steam safety relief valves had seat leakage since about January 1993. The steam leakage was routed to the suppression pool thus causing elevated temperatures in the suppression pool. In order to maintain the suppression pool within its design temperature parameters, the Division II RHR heat exchangers were selected to be used almost exclusively in the suppression pool cooling mode until approximately January 1996 when the leaking safety relief valves were modified to prevent seat leakage. Because a suppression pool biofouling program had not been established and cleaning was limited, a mechanism was in place which had the potential for causing biofouling on the shell side of the RHR heat exchangers. The inspectors noted that the Division I RHR heat exchangers were rarely used in the suppression pool cooling mode, and thus the percentage difference in organic composition amounts between the two divisions was credible.

The licensee initiated Engineering Request 97-0716 dated September 29, which evaluated the fabrication and installation of permanent piping and valves to facilitate chemical cleaning, and Engineering Request 97-0718 dated October 1, which evaluated installation of the chemical cleaning equipment. A 10 CFR 50.59 safety evaluation was performed on each of the engineering requests to address the technical issues. The safety evaluations determined that the changes did not constitute an unreviewed safety question, there was no impact on the plant technical specifications and the probability of occurrence of an accident previously evaluated was not increased.

The licensee contracted with Hydro-Chem, Inc. for engineering services and PN Services, Inc. for performance of chemical cleaning. The inspectors were informed by the licensee that each of the vendors had considerable experience regarding chemical cleaning of heat exchangers. The inspectors determined that the vendors were not on the approved suppliers list; however, the licensee had made provisions to control each vendor under the River Bend Station quality assurance program.

In conjunction with the above activities, Temporary Procedure 97-0007, Revision 0, "RHR Heat Exchanger Chemical Cleaning Procedure (Shell Side)," was developed to define and implement the chemical cleaning process. The chemical cleaning process was a two-step evaluation where Step 1 was an alkaline permanganate flush performed for destruction of organics and corrosion film conditioning. The Step 1 process continued with a sodium hydroxide solution to release the bulk of the organic biomass deposit, followed by the addition of potassium permanganate to dissolve the remaining organisms by oxidation. These flushes were completed at a temperature range of 185°F to 205°F. Upon completion of Step 1, the remaining active ingredients were removed from the system using ion exchange. Step 2 consisted of citric and oxalic acid flushes in combination for metal oxide dissolution. The system was again cleaned by ion exchange.

The results of the above flushes were effective. During Step 1, two heavily loaded bag filters were plugged and had to be replaced. During Step 2, approximately 91 pounds of iron were removed along with 1.4 curies of radioactivity. Contact dose rates were reduced by a factor as high as 7. However, inspection of the tubes after the flushes revealed a blue-white residue on the tubes which was determined to be copper oxalate. The licensee removed the residue by performing additional flushes with a weak solution of ammonium hydroxide. Water quality was restored by ion exchange.

The inspectors questioned the licensee to understand their basis for declaring the Division II RHR heat exchangers operable until the next fuel cycle. The licensee responded that postcleaning visual inspections showed that the heat exchanger shell side had been restored to a clean condition, which in turn restored excess capacity margin based on past successes with shell side cleaning of other heat exchangers. Baseline postmaintenance testing could not be accomplished with meaningful results until the beginning of Refueling Outage 8 when decay heat rates will be high enough to provide a sufficient heat load. The licensee stated that the RHR heat exchangers will be performance tested at the beginning of Refueling Outage 8. The inspectors considered this to be an acceptable approach.

Although the Division I RHR heat exchangers exhibited similar shell side fouling, but to a lesser degree, performance testing trends indicated that these heat exchangers could be safely tested and cleaned during a subsequent refueling outage. Therefore, the licensee decided not to clean the Division I RHR heat exchangers during Refueling Outage 7.

On October 10, a teleconference was held between the licensee, Region IV, and NRC headquarters personnel to discuss the licensee's actions and intended plans in response to RHR heat exchanger fouling and performance. All questions were resolved except for the licensee's long-term plans to address the source of the biofouling, which appeared to have been the suppression pool. This item will be tracked as an IFI (50-458/9714-02).

c. Conclusions

The inspectors concluded that the licensee's actions in response to degraded capacity of the Division II RHR heat exchangers was appropriate to the circumstances and corrective actions were well executed. An IFI was identified to follow the licensee's approach to the mitigation of future biofouling in the RHR heat exchangers.

E2.3 Overload of the Division II EDG During Testing

a. Inspection Scope (37551)

The inspectors reviewed the licensee's response to Condition Report 97-1784 where it was identified that the Division II EDG was momentarily overloaded during testing.

b. Observations and Findings

On October 8, 1997, during postmaintenance governor adjustments, the Division II EDG was inadvertently overloaded beyond its licensing basis rating of 3130 kilowatt (kW) for 20.4 seconds. The maximum load achieved was 3375 kW and the 3200 kW limit was exceeded for 18.8 seconds. Attachment 3 to the River Bend operating license requires that a crankshaft inspection be performed at the next refueling outage for indicated engine loads in the range of 3200 kW to 3500 kW for a period of less than 1 hour.

The Division II EDG is a Transamerica DeLaval, Incorporated Model DSR-48. The manufacturer's ratings for the machine are 3500 kW continuous with an allowable overload rating of 3850 kW. Engineering performed an operability evaluation. The evaluation stated, in part, that the loading transient was acceptable from a fatigue standpoint because the maximum stress was below the endurance limit. The inspectors reviewed the basis for the evaluation and found it excellent.

Inspectors questioned if the operating license required a crankshaft inspection during Refueling Outage 7. The licensee determined that the next refueling outage was the appropriate time to conduct the inspection and in compliance with Attachment 3 of the operating license. This conclusion was based on (1) the graded approach in required actions in Attachment 3, (2) the engineering operability evaluation, and (3) the NRC's safety evaluations establishing the license's condition. The inspectors found no problems with the licensee's position on this matter.

c. Conclusions

The licensee's evaluation of the short-duration overload of the Division II Transamerica DeLaval EDG was comprehensive and thorough. The licensee's bases for determining the crankshaft inspection requirements were appropriate.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 HRA Barrier Controls

a. Inspection Scope (71750)

The inspectors reviewed the licensee's actions in response to four instances during the refueling outage where HRA barriers were not maintained in place.

b. Observations and Findings

On September 10, 1997, the inspectors identified that the HRA rope barrier was down at the entrance to RHR Pump Room B; however, a backup gate which was properly posted was closed, therefore, TS 5.7.1 requirements were met. The inspectors restored the rope barrier and notified the RP personnel. The licensee wrote Condition Report 97-1362 to document and trend this event.

On September 14, the licensee identified that both the HRA rope barrier was dropped and the backup gate was open at the 131-foot elevation entrance to the drywell. The drywell was designated as an HRA. The barriers were promptly restored and the licensee wrote Condition Report 97-1399.

On September 16, workers entering the 141-foot elevation entrance to the main steam tunnel found the rope barrier down. The main steam tunnel was designated an HRA. Again, the backup gate was closed and thus TS 5.7.1 requirements were met. The rope barrier was restored by the workers and the licensee initiated Condition Report 97-1435.

On September 30, the licensee identified a rope barrier that was down at the 98-foot elevation entrance to the main steam tunnel, which was designated an HRA. However, the backup gate which was properly posted was closed, providing the barrier required by TS 5.7.1. The rope barrier was promptly restored and Condition Report 97-1681 was written.

In three of the four occurrences above, regulatory requirements were met to the extent that the HRA barriers were maintained intact with properly posted backup barriers. On September 14, however, both barriers were not in place. TS 5.7.1, in part, requires the entrances to HRAs to be barricaded and conspicuously posted as HRAs. The licensee revised the appropriate procedures to move all HRA barrier ropes from approximately 3 to 5 feet above the floor, so that personnel entering an area would not have to take the rope down to pass through. Additionally, backup barriers were modified to spring close after a worker passed through. All site supervisors reviewed HRA and locked HRA requirements with personnel. The licensee also included emphasis on radiation area barriers in the "Outage Update" publication on September 18 and September 24. The barrier changes appeared to have corrected the problem. No further barrier problems were identified as of the end of this inspection period. Failure to maintain the appropriate HRA barrier at the 131-foot elevation entrance to the drywell, which was an HRA, is a violation of TS 5.7.1. This nonrepetitive, licensee-identified and corrected violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-458/9714-03).

c. Conclusions

An NCV was identified involving the failure to properly maintain HRA barriers in accordance with the requirements of TS 5.7.1.

R1.2 LHRA Barrier Controls

a. Inspection Scope (71750)

The inspectors reviewed the licensee's actions in response to two incidents where LHRA barriers were not controlled as documented in Condition Reports 97-1492 and 97-1783.

b. Observations and Findings

On September 19, 1997, the LHRA boundary fence was found partially removed from around Valve E12 AOV41A. This valve was located in the drywell near safety relief Valve B21-VF041A. Workers were in the process of removing the safety relief valve. LHRAs were defined by the licensee's procedures as areas accessible to individuals, in which radiation levels could result in an individual receiving a deep dose equivalent in excess of 1000 millirem in 1 hour at 12 inches (30 centimeters) from the radiation source or from any surface that the radiation penetrates.

Prejob briefings were held by RP and the workers were briefed to contact RP when their work was impacted by an LHRA. However, without notifying RP for support, a worker climbed over a handrail that was posted as a LHRA to position the hoist and attempted to connect the hook to the rigging on the safety relief valve. Unable to make the connection, the worker climbed further down toward the valve until he was at the orange fence barrier surrounding Valve E12-AOV41A. He removed several tie wraps that secured the fence in place and rolled back approximately 4 feet of fence to make room for the rigging and the hoist hook. One of the LHRA posting signs was rolled up in the material and no longer visible. This was done without the knowledge of RP.

Approximately 30 minutes later, RP shift supervision became aware of the breach. RP technicians were directed to restore the barrier and control access to the area until the barrier was restored. The RP shift supervisor stopped work in the drywell to meet with the workers and debrief the event. Work was not resumed until personnel working in the drywell clearly understood the requirement for RP coverage and authorization when it became necessary to alter or move any radiological posting or barrier.

Disciplinary action was taken against the individual who breached the LHRA barrier. Additionally, the licensee conducted a root cause determination, which identified other coordination and communication problems associated with the replacement of the safety relief valve.

TS 5.7.3 states, in part, that individual HRAs with radiation levels of 1000 millirem per hour or greater that cannot be locked in an enclosure, shall be barricaded and conspicuously posted. Failure to properly maintain a LHRA barrier and posting is a violation of TS 5.7.3 (50-458/9714-04).

On October 8, an RP technician found the gate to Radwaste 136-foot elevation drum storage area unlocked. This area was designated as a LHRA. After verifying there were no personnel in the area, the RP technician locked the gate. The licensee initiated Condition Report 97-1783 and commenced an investigation. This gate was one of three LHRA doors in the radwaste building that did not automatically lock when latched, which may have contributed to the occurrence. A similar incident occurred on November 14, 1996, when one of the three doors was found unlocked by the licensee. This was documented in NRC Inspection Report 50-458/96-16. An NCV was identified because it was an isolated incident for which the licensee implemented appropriate corrective action. At that time, the licensee initiated an investigation to determine if the three doors that did not lock automatically could be modified so that all LHRA doors locked automatically when latched. However, because of the design effort involved, the doors did not get modified. If the licensee had completed this corrective action, it was credible that the gate to the drum storage area would not have been left unlocked on October 8.

TS 5.7.2 states, in part, that areas with radiation levels of 1000 millirem per hour or greater, shall be provided with locked or continuously guarded doors to prevent unauthorized entry. Failure to maintain the radwaste drum storage area gate locked is a violation of TS 5.7.2 (50-458/9714-05).

c. Conclusions

There were two incidents where LHRA barriers were not properly controlled because of inattention to RP requirements. One incident could have been prevented if timely corrective actions had been implemented subsequent to a similar incident in November 1996.

R1.3 ALARA Activities

a. Inspection Scope (71750)

The inspectors reviewed the licensee's ALARA performance during Refueling Outage 7.

b. Observations and Findings

The licensee had projected a Refueling Outage 7 radiation exposure goal of 245 person-rem. This was based on a 22-day outage. Minor delays in scheduled work and added emergent work, i.e., chemically cleaning the RHR heat exchangers, extended the outage to 39 days. However, the licensee still only expended 207 person-rem for the entire outage, which was 38 person-rem under the projection.

The inspectors noted, throughout the outage, that there was a strong awareness of radiation exposures and maintaining exposures ALARA. Prior to the outage, the licensee implemented initiatives to reduce the source term. For example:

- The main turbine rotors were replaced.
- Main steam isolation valve anti-rotation modification.
- Nonstellite control rod blades were installed.
- Zinc injection chemistry in reactor coolant (Began June 25, 1997)

The licensee accomplished the following initiatives during Refueling Outage 7 to help reduce the source term:

- Flush of the reactor water cleanup strainers in the valve nest room.
- Chemical cleaning of the Division II RHR heat exchangers.

- Flush of reactor water cleanup line for penetration work in the 95-foot elevation reactor core isolation cooling system room.

Improved materials condition of the plant contributed to exposure reduction for the outage. A number of ECCS valves typically requiring work had passed their inservice tests. MSIVs required no internal work.

Other initiatives, such as lowering the work package exposure review threshold for the ALARA committee, improved use of low dose waiting areas, remote video monitoring of equipment in HRAs, and prompt removal of high radiation trash from work areas, helped contribute to the licensee's success.

c. Conclusions

The licensee demonstrated excellent performance in reducing radiation exposures ALARA. A scheduled 22-day refueling outage goal of 245 person-rem was established. Even though the outage was extended to 39 days, the total outage exposure was only 207 person-rem.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

During routine tours, the inspectors noted that the security officers were alert at their posts, security boundaries were being maintained properly, and screening processes at the primary access point were performed well.

S1.2 Inadequate Lighting in Extended Protected Area

a. Inspection Scope (71750)

The inspectors performed night tours of the protected area to determine if the protected area was properly illuminated.

b. Observations and Findings

On August 29, 1997, the licensee extended the protected area boundary to include the contractor temporary trailer area to facilitate outage preparations. On September 3 at 11:45 p.m., the inspectors performed a night tour of the extended protected area to ensure that this area was being maintained in accordance with the physical security plan. The inspectors noted that between Trailers 39 and 40, there was a porch with a ramp for entry into these trailers. The inspectors noted that it was dark underneath this porch and no temporary lighting had been installed. The inspectors informed the security shift superintendent who performed a survey of the area with a light meter. This area was found to be illuminated to less than 0.2 foot-candles as required by the physical security plan. The licensee installed temporary lighting under the porch which is a compensatory measure required by the security plan.

Although the lighting was degraded in the area of the temporary trailers, the security shift superintendent stated that he could see a person hiding underneath the temporary porch. The inspectors determined that this was not a significant degradation of physical security. Subsequently, the security superintendent had a wooden skirt installed around the porch to prevent personnel entry underneath.

c. Conclusions

The security department's preparations for opening the temporary protected area may not have been thorough, in that they failed to identify a darkened area underneath a wooden porch. The licensee's response to this problem was satisfactory.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 17, 1997. The licensee acknowledged the findings presented.

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

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. P. Dimmette, General Manager, Plant Operations
M. A. Dietrich, Director, Quality Programs
D. T. Dormady, Manager, System Engineering
H. B. Hutchens, Superintendent, Plant Security
D. N. Lorfing, Supervisor, Licensing
J. R. McGaha, Vice President-Operations
M. G. McHugh, Licensing Engineer III
W. P. O'Malley, Manager, Operations
D. L. Pace, Director, Design Engineering
R. L. Roberts, Acting Manager, Maintenance
A. D. Wells, Superintendent, Radiation Control
C. L. Young, Acting Superintendent, Chemistry

INSPECTION PROCEDURES (IP) USED

IP 37551	Onsite Engineering
IP 60710	Refueling Activities
IP 61726	Surveillance Observations
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities

ITEMS OPENED AND CLOSED

Opened

50-458/9714-02	IFI	Long-term plans to address RHR biofouling (Section E2.2)
50-458/9714-04	VIO	Failure to properly maintain a LHRA barricaded and posted (Section R1.2)
50-458/9714-05	VIO	Failure to maintain a LHRA door locked (Section R1.2)

Opened and Closed

50-458/9714-01	NCV	Inadequate scram time test procedure (Section M1.6)
50-458/9714-03	NCV	Failure to maintain HRA barriers (Section R1.1)

LIST OF ACRONYMS USED

AISI	American Iron and Steel Institute
ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
ECCS	emergency core cooling system
EDG	emergency diesel generator
HRA	high radiation area
IFI	inspection followup item
IP	inspection procedure
kW	kilowatt
LHRA	locked high radiation area
MAI	maintenance action item
NCV	noncited violation
PDR	Public Document Room
RHR	residual heat removal
RP	radiation protection
TS	Technical Specification
VIO	violation
VASASP	valve adjusting screw swivel pad