ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-458
License No.:	NPF-47
Report No.:	50-458/97-013
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana 70775
Dates:	July 20 through August 30, 1997
Inspectors:	W. F. Smith, Senior Resident Inspector D. L. Proulx, Resident Inspector T. H. Andrews, Radiation Specialist, Division of Reactor Safety
Approved By:	Elmo E. Collins, Chief, Project Branch C

Attachment: Supplemental Information

9709300047 970926
PDR ADOCK 05000458
G PDR

EXECUTIVE SUMMARY

River Bend Station
NRC Inspection Report 50-458/97-013

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

Operations

- In general, the performance of plant operators was professional and reflected a focus on safety (Section O1.1).

- Plant operators failed to properly restore a clearance. Consequently, the neutral breaker for the Division I emergency diesel generator (EDG) was inappropriately left open after completion of maintenance (Section O1.2).

- Overall performance of receipt inspection and storage of new reactor fuel was very good. Personnel involved demonstrated excellent ownership and teamwork. Quality Assurance and licensee management provided effective oversight. However, the licensee identified one case where a fuel assembly was not properly controlled as it was being seated (Section O1.3).

- The shift superintendent's decision to shut down the plant when a 0.5 gpm step change in unidentified leakage occurred was conservative and in the interest of plant safety. The shutdown, cooldown and restart were conducted without incident and in accordance with licensee procedures (Section O2.1).

- The operators and support personnel responded well to the main turbine trip and resultant reactor scram of August 22. After repairs, the plant was started up in a controlled, error-free manner (Section O2.2).

- Plant staff failed to identify that safety relief valves lifted due to high pressure, despite available data that should have permitted discovery. The posttrip review checklist contained incomplete information with respect to safety relief valve (SRV) actuations during the trip, when needed data was available but not used. The Facility Review Committee (FRC) demonstrated poor performance by not challenging the information prior to approving the report for startup. As a result, the licensee failed to perform an engineering evaluation prior to startup after the SRVs lifted in the self-actuated safety move (Section O2.2).

- The licensee established a comprehensive and effective program for the control and authorization of overtime in response to a previous violation. The licensee identified an isolated failure to comply with Procedure RBNP-086, "Control and Authorization of Overtime," Revision 0 (Section O8.2).

<u>Maintenance</u>

- Plant material condition has continued to be very good based on the normal response to the scram on August 22, 1997 and the plant shutdown on July 24, 1997. Also, the start-up from the two outages were free of significant equipment problems except for the failure of reactor feed Pump B (Sections O2.1, O2.2).

- The forced outage of July 24-29 was well coordinated and executed. Necessary work and testing was satisfactorily accomplished during the plant shut down (Section O2.1).

- Maintenance activities observed were conducted satisfactorily. The intent of the instructions were properly followed and the technicians demonstrated a good questioning attitude (Section M1.1).

- In general, the establishment of freeze seals and replacement of standby service water (SSW) system valves were performed well (Section M1.2).

- Plant staff failed to perform a proper safety evaluation when performing EDG maintenance on line. The system engineer identified this issue and plant staff performed a good investigation and root cause analysis (Section M1.3).

- The licensee failed to focus sufficient attention on the potential safety impact of allowing structural work in the suppression pool area while the reactor was at power. As a result, foreign material exclusion controls were inadequate (Section M1.4).

- The surveillance tests observed were properly performed in accordance with the applicable procedures. However, the inspector noted an isolated example of poor physical separation between the independent verifier and the initial verifier. The licensee took appropriate corrective action (Section M1.5).

- The licensee failed to properly consider the design basis of the Residual Heat Removal (RHR) Pump Room A water tight door when the door was blocked open to stage instrument cabling for thermal performance testing of the RHR heat exchangers for the September 12, refueling outage (Section M1.6).

- While conducting operational testing of the fire pumps, test personnel failed to obtain the proper approvals to proceed after obtaining unexpected results for the sequential cranking test (Section M1.7).

- The licensee's actions in response to the repeated failures of the Division II EDG intake air adapter weld were appropriate to the circumstances (Section M2.1).

- Maintenance personnel overgreased the fan motor bearings of the standby gas treatment system (SGTS) (Section M2.2).

Engineering

- The system engineer demonstrated a good, questioning attitude by challenging the FRC-approved posttrip review which concluded that the SRVs lifted in the relief mode rather than the safety mode (Section O2.2).

- Design engineers identified nonconservative values in the design basis for Division III battery load profiles. The inspectors concluded that the licensee had taken good corrective action in response to previously identified errors in the calculations for the Divisions I and II batteries (Section E1.1).

Plant Support

- Housekeeping was good (Section O1.1).

- Reactor fuel receipt inspection personnel were not appropriately trained on fire protection requirements. This issue was similar to a finding in a recent NRC fire protection functional inspection (Section F1.1).

Report Details

Summary of Plant Status

At the beginning of this inspection period, the plant was operating at 100 percent power. On July 24, 1997, the plant was shut down and cooled down to ambient conditions to replace a degrading seal on Reactor Recirculation Pump A. On July 31, the plant was restored to 100 percent power. On August 7, the reactor began to coast down. On August 22, while operating at 93 percent power, an automatic reactor scram with a turbine trip occurred because of a failure in the turbine electrohydraulic control system. After repairs, power was restored to 93 percent by August 24. At the end of this inspection period, power had decreased to 92 percent.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors visited the control room and toured the plant on a frequent basis including periodic backshift inspections. In general, the performance of plant operators was professional and reflected a focus on safety. The utilization of three-way communications continued to improve and operator responses to alarms were observed to be prompt and appropriate to the circumstances. Human errors continue to appear as discussed below; however, self-checking and peer-checking were used effectively. The inspectors also attended the licensee's Plan-of-the-Day meetings on a routine basis to evaluate communications between departments. The inspectors noted strong management awareness of developing and on-going problems during these meetings. Teamwork and cross-discipline cooperation was evident, as demonstrated in the excellent performance of site personnel in response to the forced outages discussed below.

During tours of the facility, the inspectors found that housekeeping was generally good, with some exceptions. Licensee outage preparations resulted in some housekeeping deficiencies, such as a scaffolding cart left unrestrained near safety-related equipment. Condition Reports (CRs) were written when appropriate and the licensee corrected the problems expeditiously.

O1.2 EDG Neutral Breaker Found Open

a. Inspection Scope (61726)

During surveillance testing of the Division I EDG, an operator discovered that the EDG neutral breaker (EGS-ACB11) was open when it should have been closed. The inspectors reviewed the licensee's root cause determination and corrective actions in response to the incident.

b. Observations and Findings

On July 17, 1997, a licensed operator assisting with the Division I EDG operability test identified a control room indication that the generator neutral breaker was open. The operator directing the test and the Shift Superintendent were promptly notified and the test was halted.

Prior to the test of the EDG, two clearances had been implemented (Protective Tagouts 97-0725 and 97-0728). The restoration portion of Protective Tagout 97-0725 specified "neutral after closed" for the generator neutral breaker control switch in the main control room. The inspectors reviewed the documentation for the clearance and noted that the required position for the breaker was clearly stated, signed off as positioned as required and then independently verified. Before proceeding with the test of the EDG, the main control room and the local EDG control panels were verified to be in the correct lineup. The operators also reverified the restored positions of valves and breakers listed on the two clearances. No additional problems were found.

Operations management performed an investigation into the root cause(s) of this configuration control problem. The licensee had implemented several corrective actions in response to a notice of violation in NRC Inspection Report 50-458/96-015, that identified four examples of configuration control problems. Operations management found that the individuals involved with the restoration of the breaker did not properly determine the position. The individuals verified the remote handle was in the neutral position but failed to note the mechanical flag was green, which indicated open and failed to note the indicating light, which also indicated the breaker was open. The individuals involved were disqualified from clearance work, disciplinary action was taken and all of the operators were counseled on the importance of clearance configuration control and specific lessons learned from this incident.

Section 7.10 of Administrative Procedure ADM-0027, "Protective Tagging," Revision 16, requires that the operator designated to remove Danger-Hold tags shall be responsible to perform tag removal and component positioning in the sequence shown on the Clearance Removal Sheet. In addition, Section 7.10 requires the independent verifier to verify restoration of the clearance and initial each step. Failure of the individuals responsible to perform these functions during the removal of Protective Tagout 97-0725 resulted in Breaker EGS-ACB11 not being closed, as required, for operation of the Division I EDG. Although the breaker being out of proper position was identified by the licensee, which demonstrated good attention to detail by the operator who found the problem, the NRC criteria were not met for an NCV. Corrective actions implemented for past configuration control problems could reasonably have been expected to prevent the violation. Therefore, failure to properly remove or verify removal of the tag, as required by Procedure ADM-0027, is a violation of the T.S. 5.4.1.a requirement to adhere to procedures (50-458/97013-01).

c. Conclusions

The inspectors concluded that plant operators, fully qualified to administer clearances, failed to properly focus attention on the details involved in restoring a clearance. Consequently, the neutral breaker for the Division I EDG was inappropriately left open after completion of maintenance. A violation of TS 5.4.1.a was identified for failure to follow protective tagout restoration procedures.

O1.3 Receipt Inspection of New Fuel

a. Inspection Scope (60705)

The inspectors observed the receipt inspection and storage of new reactor fuel assemblies to be loaded in the reactor during the approaching refueling outage. In addition to the inspection procedure, the inspectors focused on the deficiencies identified with fuel receipt inspection activities during the Fuel Integrity and Reactor Subcriticality (FIRS) inspection conducted in 1996 (NRC Inspection Report 50-458/96-001).

b. Observations and Findings

On July 30, 1997, the inspectors observed portions of the training and qualification activities conducted with the first new fuel assemblies that were unloaded. The qualification was being conducted under the supervision of both the General Electric (GE) fuel vendor representative and licensee supervision. These activities were conducted in an efficient and professional manner. Portable criticality monitors were in the area and evacuation drills were held as required by 10 CFR 70.24.

On July 31 through August 13, the inspectors observed new fuel receipt inspection, assembly of the fuel bundles to the channels and storage of the fuel assemblies in the spent fuel pool. The personnel involved in the activities demonstrated good teamwork and coordinated the various parts of the process in an effective manner. Lessons learned from the 1996 FIRS Inspection were incorporated into the process. For example, the requirement to verify that the maximum dimension between the outer surface of the channel fastener guard and the channel was less than 0.208 inch was implemented by a procedural requirement to use a go-no-go measuring tool. During the FIRS Inspection, the licensee had identified that one fuel inspector was accepting this dimension through visual observation rather than taking a direct measurement.

The fuel assembly misorientation problem identified during the FIRS Inspection was resolved by placing all assemblies in the same orientation in the spent fuel pool. There were no orientation problems noted by the inspectors during this activity. A third issue identified during the FIRS Inspection was damaged channel fastener springs caught on the spent fuel rack, because the springs were not inspected by the fuel vendor or the licensee. An inspection step was incorporated to ensure the springs were not sprung out of the channel fastener guard groove, or were otherwise damaged.

On August 4, while lowering Fuel Assembly HGE274 into spent fuel pool location GG-10, the spotter and the Quality Assurance inspector noted that the assembly lowered the last 2 to 4 inches faster than normally observed and a cloud puffed out. The mast full down light was energized and the assembly appeared fully seated. Normally, the mast full down light is not energized upon seating assemblies. In this case, the mast position was indicating approximately 1/2 inch lower than normally seen. The fuel handler attempted to ungrapple the assembly, but could not, although the slack cable light was energized and there was no load on the load cell. Subsequently the assembly was reseated and the grapple released normally. With the assembly in a safe condition, new fuel receipt inspection and storage activities were halted and CR 97-1146 was written to enter the problem into the licensee's corrective action program.

On August 5, the team held a meeting to discuss the incident and determine a corrective action plan. The team reviewed Fuel Handling Procedure FHP-0002, "Fuel Handling Platform Operation," Revision 10, to determine if there were any questions or clarifications to address. The fuel handling platform was exercised using a blade guide and there were no malfunctions. The technical surveillance requirement was performed on the platform in accordance with the applicable portions of Surveillance Test Procedure STP-055-0702, "Refuel Platform Hoist Operability," Revision 9B, with satisfactory results.

The licensee concluded that the platform and hoist functioned properly. The fuel assembly apparently met sufficient resistance from the spent fuel pool rack as it was being lowered, to partially unload the hoist cable until it dropped by its own weight with a slack cable. The fuel handler did not maintain appropriate cognizance over the load cell indication as he lowered the assembly. The load cell normally provided the first indication of assembly binding. The inspectors considered load cell monitoring to have been fundamental; however, Procedure FHP-0002 did not list any precautions or action steps to instruct the fuel handler to monitor the load cell indication concurrent with the mast position. Also, there was an inconsistency as to when each hoist operator shifted to the "jog" mode for slower, more controlled insertion of the fuel assemblies into the seated position. The licensee posted an operator aid that identified key vertical position indications for specific transition points on the hoist and provided coaching on lessons learned from this event. Because of the possibility of binding, the licensee also initiated a revision to Procedure FHP-0002 to incorporate specific precautions with regard to appropriate use of the "jog" mode for speed control when seating a fuel assembly and to maintaining cognizance over load cell indication when handling fuel. The appropriate training request was also generated for future evolutions.

On August 13, Fuel Assembly HGE274 was withdrawn from the spent fuel pool rack and dechannelled for inspection to determine if damage occurred. The inspectors witnessed the inspection, which was thorough and conducted in the presence of a GE representative. No damage was found, as expected.

Failure to maintain adequate instructions in Procedure FHP-0002 to control the insertion of fuel assemblies in the spent fuel pool rack is a violation of TS 5.4.1.a. This non-repetitive, licensee-identified and corrected violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-458/97013-02).

c. Conclusions

Overall performance of receipt inspection and storage of new reactor fuel was very good. Personnel involved demonstrated excellent ownership and teamwork. Quality Assurance provided effective oversight, as did licensee management. However, the licensee identified one case in which a fuel assembly was not properly controlled as it was being seated. An NCV was identified for an inadequate fuel handling procedure.

O2 Operational Status of Facilities and Equipment

O2.1 Forced Shutdown Caused by Reactor Recirculation Pump Seal Leakage

a. Inspection Scope (93702)

The inspectors responded to the control room to monitor the licensee's actions in response to increased unidentified leakage and decreasing pressure on the second stage of the shaft seal on reactor recirculation Pump A.

b. Observations and Findings

On July 24, 1997, at 11:00 p.m. the licensee commenced a reactor shutdown because of decreasing second stage pressure on the reactor recirculation Pump A seal and increasing drywell unidentified leakage. Reactor power was decreased to approximately 30 percent and the shutdown was completed by a manual reactor scram at 11:16 a.m. per the licensee's normal shutdown sequence. At the time of the shutdown, the second stage seal pressure of recirculation Pump A was 440 psig and the drywell unidentified leak rate was 3.24 gpm.

The licensee had been tracking a slow increase in unidentified leak rate since June 29, 1997. From June 29 through July 19, 1997 the leak rate increased from approximately 0.10 to 0.88 gpm. From July 19 through July 23, the leak rate accelerated such that on July 23 the leak rate was 1.59 gpm. Also during this time period, the licensee noted a sharp increase followed by a slower decrease in second stage pressure of the recirculation Pump A seal. Based on this information, licensee management had planned a controlled shutdown to commence on July 25 at 7 p.m. However, on July 24 at 11 p.m., the licensee experienced step changes in both drywell unidentified leakage and second stage seal pressure on recirculation Pump A. Unidentified leakage increased from 1.9 to 2.4 gpm in a short period of time. Therefore, the shift superintendent commenced a controlled reactor shutdown. At the time of the manual scram to complete the shutdown, drywell unidentified leakage had reached a peak of 3.24 gpm. The Technical Specification limits for unidentified leakage are 5 gpm or a 2 gpm rate increase in 24 hours. The inspectors noted that neither limit was exceeded during this event and all systems responded as expected during the shutdown. The licensee did not enter any emergency plan implementing procedures.

After the shutdown, the licensee entered the drywell to perform an inspection. The licensee found the reactor recirculation Pump A seal leaking and no other significant leaks in the drywell. Following the drywell inspection, the licensee commenced cooldown of the plant to Mode 4 (Cold Shutdown).

The inspectors responded to the control room and witnessed the shutdown and portions of the cooldown. Both of these evolutions were conducted carefully and in accordance with the applicable procedures. Self-checking and 3-way communications were evident throughout the shut down and cooldown. At times, licensee management was observed in the control room providing oversight.

During the forced outage, the licensee replaced the seal package on reactor recirculation Pump A, performed miscellaneous maintenance and surveillance items and performed the service discharge surveillance test on the Division III safety-related battery (discussed below in Section E1.1 of this inspection report). The licensee disassembled and inspected the failed seal to determine the failure mechanism. Inspection of the rotating seal faces revealed circumferential scoring and the stationary carbon seal faces had a washed, eroded appearance. The licensee considered this to be caused by particulates (corrosion products, etc.) between the seal faces. Such particulates would normally be excluded by a properly functioning seal mechanism.

The mating surface between the quad ring and the balance sleeve appeared to indicate that the quad ring was sticking, thereby not allowing the spring-loaded stationary seal to follow the rotating seal as it moved axially with thermal changes during startup. This could explain why the intermittent leakoff alarms annunciated during startups and power ascensions. If the stationary seal failed to maintain contact with the rotating seal, the seal probably opened enough to admit particulates which then remained trapped between the faces and caused the scoring described above.

The licensee stated that they were addressing the quad ring to balance sleeve interface as a problem with the vendor to determine any corrective actions that could be taken in the future to prevent a recurrence of this type of failure.

On July 29, the plant was started up and heated up to normal operating temperature and pressure. The drywell was inspected for leaks and none were found. The reactor recirculation pump seal performed as designed with no leakage. The inspectors observed portions of the startup activities and noted that the startup was accomplished error-free, in a well-controlled manner. By July 31, full power operation was restored and drywell unidentified leakage was stable at approximately 0.1 gpm, where it remained until the end of the inspection period.

c. Conclusions

The shift superintendent's decision to shut down the plant when a 0.5 gpm step change in unidentified leakage occurred was conservative and in the interest of plant safety. The shutdown, cooldown and restart were conducted without incident and in accordance with licensee procedures.

The forced outage of July 24-29 was well coordinated and properly executed. Necessary work and testing was satisfactorily accomplished as planned, as well as utilization of the opportunity to complete other maintenance and surveillance items with the plant shut down.

O2.2 Reactor Scram Caused by Main Turbine Trip

a. Inspection Scope (93702)

The inspectors reviewed the licensee's response to an automatic reactor scram that occurred on August 22, 1997 and observed portions of the startup and restoration of full power operation.

b. Observations and Findings

On August 22, at 12:26 a.m., while operating at 93 percent power, an automatic reactor scram occurred because of a main turbine-generator trip. The operators were in the process of conducting control rod operability surveillances and no work was ongoing that might have perturbed the plant. Offsite power was not lost and the Division III EDG was nearing completion of a 24-hour loaded surveillance run. All systems responded properly, except that reactor recirculation flow control Valve B failed to run back and instead locked up as designed. This was of no consequence under the circumstances, because the runback was a nonsafety-related feature that facilitated recovery from a feedwater pump failure. In this case the reactor scram had already occurred. Because of shrink, reactor vessel level reached low Level 3 and the suppression pool cleanup system automatically isolated, as designed. When the safety-relief valves (SRV) lifted, the resultant water swell caused a Level 8 trip of the feedwater pumps; however, the operator placed one feedwater pump back in service before reactor water level returned to Level 3. By 12:50 a.m., reactor water inventory was stable at the normal operating level and pressure was being maintained by the turbine bypasses. The licensee elected to remain in Mode 3 (hot shutdown) pending determination of the cause of the reactor scram. The inspectors concluded that the event was handled in an excellent, error-free manner by the operating crew. They stabilized the plant quickly and in accordance with applicable procedures.

The licensee formed a Significant Event Response Team (SERT) to determine the causes of the reactor scram and establish corrective actions. The SERT determined that a partial short circuit occurred in the connector supplying power to a normally energized solenoid valve in the main turbine emergency trip system. This caused the solenoid valve to change position releasing the emergency trip system dump valve, which in turn fast-closed the turbine control valves and stop valves. An anticipatory signal was sent to the reactor protection system, scramming the reactor. The connector was promptly repaired and tested satisfactorily.

The inspectors noted that the August 22, 12:26 a.m. operator log entry stated that 12 SRVs lifted. The inspectors questioned whether the SRVs lifted at their setpoints. In response, the licensee stated that the lift pressures could not be obtained, because the plant computer data points from the pressure transmitters were out of service for repairs. However, the highest recorded pressure from the control room recorder was 1084 psig, which was below the lowest SRV relief setpoint of 1103 psig. There was a blank place in the recorder trace indicating that there was a pressure spike that may have been too rapid for the ink to flow onto the recorder paper. Based on the SRV tailpipe temperature traces and the knowledge that it was expected for the SRVs to lift during this transient as discussed in the Updated Final Safety Analysis Report (UFSAR), the licensee concluded that there was an automatic relief lift (not a self-actuated safety lift) of all 16 SRVs. The SRV tailpipe temperature traces indicated that 6 SRVs lifted for a much shorter interval than the remaining 10 SRVs. The Post Trip Review Checklist (Enclosure 1) of General Operating Procedure GOP-0003, "Scram Recovery," Revision 11, contained a footnote that indicated the SRV lift was expected, that the maximum pressure sensed by the plant computer was 1084 psig and this instrument was not calibrated and could possibly read as high as 1123 psig, the pressure corresponding to all SRVs opening. The report was reviewed and approved by the FRC for startup.

After completing startup preparations and a few necessary work items, the plant entered Mode 2 (Startup) on August 22, at 6:25 p.m. Later that evening, while the SRV system engineer was collecting data for a report relative to the SRV lift, the system engineer questioned the validity of the assumption that there was no safety mode lift during the transient. Plant computer data was obtained that indicated that none of the SRV solenoid air valves had energized and none of the slave relays from the SRV trip units had changed state, thus confirming that there was no automatic relief lift. However, since SRV tailpipe temperature recorder traces and plant computer traces providing main steam flow data indicated that the SRVs had actuated, the actuation must have been in the safety mode. This was further supported by the fact that SRVs actuated in the safety mode in 1986 and in 1993

(CRs 86-0677, 86-0752 and 93-0621B) under comparable circumstances. In a letter dated August 7, 1986, GE stated that SRVs lifting against their springs in the safety mode with reactor pressure below the nominal setpoint of the SRVs could have been caused by a pressure wave produced by main steam isolation valve or turbine stop valve closure.

The system engineer initiated CR 97-1268, to identify noncompliance with the posttrip review checklist. The checklist required an engineering evaluation of any observed premature SRV lifts in the safety mode prior to restart.

The inspectors questioned licensee management about the extent the SRV lift was discussed at the FRC meeting that reviewed the posttrip review checklist. The licensee responded that the SRV lift was not discussed at length, because the lift was expected during a load reject transient. The inspectors concluded that the basis for the statement in the posttrip review regarding the status of SRVs was inadequate and should have been challenged by the FRC. As discussed above, sufficient information was retrievable to determine if the SRVs lifted in the safety mode.

Failure to identify SRV lifts in the safety mode and perform an engineering evaluation of the event prior to restart on August 22 as required by Procedure GOP-0003, Enclosure 1, is a violation of TS 5.4.1.a (50-458/97013-03).

Failure to identify that the SRVs lifted in the safety mode for evaluation prior to startup was not safety significant in this instance, because the lift of SRVs during a load rejection was addressed in UFSAR Section 5.2.2.2.2.2. The licensee has continued its evaluation of these issues as of the end of this inspection period. Actions such as revising Procedure GOP-0003 to more clearly articulate the need for an engineering evaluation prior to startup if an SRV lift occurred during a reactor scram event are/were being considered. The licensee was also developing an analysis to better support the concept of pressure waves in the steam headers on a load rejection.

The inspectors observed portions of the startup evolution on August 23 and noted that the operators were limiting access to the control room to prevent unnecessary distractions and that the Control Room supervisor demonstrated good command and control practices. The startup procedure was followed closely as were the applicable system operating procedures. In general, the operators and supporting organizations demonstrated good performance throughout the startup and ascension to power. The only significant challenge was the unavailability of feedwater Pump B which was out of service because of overheated pump bearings. However, maintenance personnel proceeded to implement timely repairs. The inspectors noted that the pump may not be needed until after the refueling outage because the reactor was coasting down to a power level that could be achieved with the remaining two feedwater pumps.

c. Conclusions

The operators and supporting plant personnel responded well to the main turbine trip and resultant reactor scram of August 22. After repairs, the plant was started up in a closely controlled, error-free manner.

Plant staff failed to identify that safety relief valves lifted due to high pressure, despite the availability of data that should have permitted discovery. The Facility Review Committee also failed to detect the inadequate posttrip review. In addition, the posttrip review checklist contained incomplete information with respect to SRV actuations during the event. A violation was identified because an engineering evaluation required when SRVs lifted in the self-actuated safety mode was not performed prior to startup.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) 50-458/96-016: control building chiller timer defeat switch left in test position. This event was addressed in NRC Inspection Report 50-458/96-015. Failure to properly align the test switch in accordance with the system operating procedure was identified as one of four examples of a violation regarding configuration control failures. The LER was accurate and adequately described the event and its safety implications, which were minor for the specific switch positioning, but more than minor in terms of the overall problem of configuration control deficiencies. Corrective actions will be evaluated during a future inspection when the violation closure review is performed.

O8.2 (Closed) Violation 50-458/97006-01: failure to establish and maintain adequate controls over personnel overtime as required by TS 5.2.2.e. As of March 1997, licensee procedures did not include specific controls for plant manager approval of overtime extensions or monthly reviews of overtime usage for Maintenance, Radiation Protection or Plant Engineering personnel who were performing safety-related functions. Consequently, a number of such personnel exceeded the specified overtime limits without proper consideration and approval from the appropriate management.

On May 19, 1997, the licensee issued and implemented River Bend Nuclear Procedure RBNP-086, "Control and Authorization of Overtime," Revision 0. The procedure was comprehensive and applied to all River Bend personnel engaged in safety-related or nonsafety-related work other than those engaged in administrative or managerial duties. The procedure provided a uniform method for overtime control.

Information on the new procedure was disseminated to all affected individuals and organizations. A reminder was sent out prior to the forced outage of July 24. Inspector reviews identified only one minor discrepancy in implementing the new procedure.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on Maintenance Activities

a. Inspection Scope (62707)

The inspectors observed portions of work activities covered by the following maintenance action items (MAI):

- MAI P593935: Inspect, clean, test and lubricate 4160-Volt Breaker ACB 3 for the 480-Volt high pressure core spray bus (August 19, 1997).
- MAI 305544/6: Repair cracks in the Division III bus support seals by applying silicone cement in accordance with vendor instructions (August 19, 1997).

b. Observations and Findings

The inspectors found the work performed under the above listed MAIs was performed in a professional manner and in compliance with the intent of the work instructions. Maintenance technicians demonstrated good foreign material exclusion practices. The inspectors frequently observed the presence of supervision and system engineers monitoring job progress and resolving questions. Appropriate clearances were utilized for personnel and equipment safety and the operators entered the correct TS limiting conditions for operation (LCO).

c. Conclusions

Maintenance activities observed during this inspection period were conducted satisfactorily. The intent of the instructions were followed and the technicians demonstrated a good questioning attitude, which resulted in additional improvements to the instructions for future use.

M1.2 Replacement of SSW Valves Using Freeze Seals

a. Inspection Scope (62707)

The inspectors observed the establishment of the freeze seals and valve replacement in accordance with MAI 308963. In addition, the inspectors reviewed Corrective Maintenance Procedure CMP-9186, "Freeze Seals," Revision 8C.

b. Observations and Findings

On August 5, 1997, the licensee commenced establishment of two freeze seals to replace manual Valves SWP-V71, -V72 and -V74 because these valves were leaking excessively. Mechanical maintenance personnel conducted a good prejob briefing and walked down the work area prior to starting. After personnel began injecting nitrogen into the freeze boots, the inspectors walked down the area to ensure that the licensee was appropriately implementing Procedure CMP-9186. The inspectors had the following comments:

- The contingencies for freeze seal failure recommended that the normally blocked open fire doors between the two trains of control room air conditioning be closed. However, during the prejob walkdown, engineering personnel stated that these doors need only be closed if a freeze seal failed. The inspectors questioned the mechanical maintenance supervisor as to why the contingency plan had not been revised to reflect actual practice. The mechanical maintenance supervisor obtained a revision to the plan.

- Procedure CMP-9186, Section 6.2, contained personnel safety precautions for personnel handling liquid nitrogen equipment to wear long sleeve shirts, face shields and leather gloves. The inspector noted that some of the mechanical maintenance personnel involved with handling of the liquid nitrogen equipment were not wearing long sleeved shirts or face shields. The inspector notified the mechanical maintenance supervisor of these safety practices. The problems were corrected.

- Procedure CMP-9186, Section 8.3.3.5 contained instructions covering when personnel should replace the liquid nitrogen tanks. This section originally contained instructions to replace the tank when the weight of its contents decreased to a given level. This required calculations to be frequently performed. Due to the inconvenience associated with this process, Procedure CMP-9186 was revised to allow replacement of the tanks based on tank level or pressure. The inspectors noted that because the nitrogen tank manifold was operated at saturated conditions, tank pressure would not have indicated low level in the nitrogen tank until the tank was nearly empty. In addition, Attachment 2 of Procedure CMP-9186 stated that tank pressure did not provide an effective correlation to the amount of liquid nitrogen remaining in the tank. Therefore, the revised Section 8.3.3.5 was incorrect. This procedural deficiency had no effect on the establishment and maintenance of the freeze seals because personnel used a tank level of approximately 1/4 full based on a frost line on the tank as the tank replacement criterion. Following the inspectors comments the licensee corrected Procedure CMP-9186.

After the freeze seals were fully established, water was drained from the applicable portion of the SSW piping and danger tags were hung on the freeze seals and other work isolation valves. The inspectors noted good coordination between operations and maintenance personnel in establishing the work boundaries. The replacement of Valves SWP-V71, -V72, and -V74 were performed in accordance with the MAI without any problems.

c. Conclusions

The establishment of freeze seals and replacement of SSW valves were performed generally well with some minor exceptions.

M1.3 Prohibited EDG Inspections Performed While Operating at Power

Inspection Scope (62707)

The inspectors evaluated the licensee's response to CR 97-1075, which discussed the performance of EDG preventive maintenance (PM) with the plant at power.

b. Observations and Findings

On July 24, 1997, the system engineer discovered that the licensee was performing web deflection testing on the EDGs during power operation, contrary to the Technical Requirements Manual (TRM). The licensee initiated a CR to enter this item into the corrective action program.

TRM Section 3.8.1.21 required, in part, that the licensee subject the EDGs to a PM program as described in the vendor manual every 18 months, but crankshaft web deflection measurement should not to be performed during Modes 1 or 2. The vendor manual recommended that the licensee measure the EDG crankshaft web deflection every 18 months. In December 1995, licensee maintenance personnel noted that the vendor manual contained a caveat that stated that it was unnecessary to perform the required PM tasks during refueling outages, but just every 18 months. Despite wording to the contrary in TRM Section 3.8.1.21, the licensee decided to perform the web deflection measurements during power operation in December of 1995. This PM task was performed for the EDGs in December of 1995 and in July of 1997. Licensee investigation of this issue revealed that the process for evaluating moving maintenance activities from refueling outages to on-line needed improvement.

The inspectors noted that the licensee has performed an increasing amount of maintenance on-line to improve the material condition of the plant. However, the inspectors had not noted any other recent examples in which work items were inappropriately performed on-line. The inspectors determined that, because the crankshaft web deflection measurement was not a very intrusive task, this item could be safely performed on-line if the licensee followed the appropriate processes.

The licensee performed the following corrective actions: (1) revised the TRM to allow certain PM tasks to be performed during power operation, (2) performed a review to determine if any other maintenance or surveillance activities were inappropriately performed during an incorrect operational mode and (3) reviewed the program that evaluated moving tasks from an outage.

The failure to perform a proper safety evaluation of a change to the TRM prior to performing the web deflection measurements during power operation is a violation of 10 CFR 50.59. This non-repetitive, licensee-identified and corrected violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-458/97013-05).

c. Conclusions

An NCV was identified for the failure to perform a proper safety evaluation prior to performing EDG maintenance on line, contrary to the TRM. The system engineer exhibited good attention to detail in identifying this issue and the licensee performed a good investigation and root cause analysis.

M1.4 Failure to Meet Foreign Material Exclusion Requirements for Suppression Pool

a. Inspection Scope (62707)

The inspectors toured the plant to verify that maintenance activities and refueling outage preparations would not impact plant operational safety.

b. Observations and Findings

The inspectors toured the plant to evaluate the effectiveness of maintenance activities and refueling outage preparations to ensure that plant safety was not being impacted or degraded as a result of work. In general, staging of materials and erection of scaffolds were not adverse to safety. Welding machines, power supplies and scaffolds were secured to appropriate structures.

On August 11, 1997, the inspectors entered the suppression pool area where Plant Modification and Construction personnel were working on a modification to expand the floor grating in the containment equipment hatch area. Most of the area was within a radioactive contamination zone. During this tour the inspectors identified an overflowing bag of used anti-contamination clothing (approximately 6 cubic feet) which was laying uncontrolled at the suppression pool step-off-pad. The inspectors concluded that this uncontrolled material could clog multiple ECCS stainers if there was a loss of coolant accident. While the inspectors were observing this activity, radiation protection personnel removed the bag of clothing. The inspectors alerted the radiation protection office and the Operations Manager of their concerns over potential suction strainer clogging, in view of a past related violation in NRC

Inspection Report 50-458/96-001 and relative to the safety concerns addressed in NRC Bulletin 93-02, "Debris Plugging of Emergency Core Cooling Suction Strainers."

The licensee suspended the work on the suppression pool grating modification until all foreign material was removed or secured and workers participated in a briefing which emphasized foreign material exclusion and the consequences of ECCS suction strainer clogging. CR 97-1186 was initiated to enter the problem into the licensee's corrective action program.

Administrative Procedure ADM-0081, "Cleanliness Control," Revision 4, required workers to minimize the use of temporary flexible material such as plastic sheeting, drop cloths and rags when in containment below the 141 foot elevation and the reactor is at power. Allowing used protective anticontamination clothing to accumulate in a large bag at the 95 foot elevation was not in compliance with this requirement and is a violation of TS 5.4.1.a (50-458/97013-05).

c. Conclusions

The licensee failed to focus sufficient attention on the potential safety impact of allowing structural work in the suppression pool area while the reactor was at power. As a result there were inadequate foreign material exclusion controls implemented. A violation was identified for failure to comply with the licensee's cleanliness control procedure.

M1.5 Surveillance Observation

a. Inspection Scope (61726)

On August 19 and 20, 1997, the inspectors observed performance of portions of Procedure STP-302-1604, which was the high pressure core spray loss of voltage channel calibration and logic system functional test.

b. Observations and Findings

The inspectors found that the surveillance was conducted properly and meaningful results were obtained. Self-checking and peer checking were evident and the test director demonstrated a strong focus on the proper performance of the test. The test director rebriefed each segment of the test immediately prior to actual performance, which was viewed by the inspectors as a strength. During independent verification, however, the verifiers demonstrated a less than optimum independence at times. The independent verifier did not maintain physical separation from the worker performing the initial verification. The inspectors observed that the test steps were properly performed and after the inspectors raised the issue, maintenance supervision took action to counsel the individuals. This action was appropriate to the circumstances. The inspectors noted that this was an isolated example of a weak independent verification. TS LCOs 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

The surveillance test observed during this inspection period was performed properly and in accordance with the applicable procedures. However, the inspector noted an isolated example of poor physical separation between the independent verifier and the initial verifier. The licensee took appropriate corrective action.

M1.6 ECCS Pump Room Water Tight Door Blocked Open

a. Inspection Scope (71707)

The inspectors reviewed the causes of the water tight door to RHR Pump Room A being blocked open during power operation of the plant, when the UFSAR indicated that the door was kept closed to protect the room from flooding.

b. Observations and Findings

On August 19, 1997, the inspectors identified that the water tight door (A95-6) to RHR Pump Room A was blocked open to allow test cables to be routed from the RHR heat exchangers to processing equipment outside the room. Section 3.4.1.1.3 of the UFSAR states that these doors are required to be closed to prevent any adverse effect from flooding. The inspectors learned that the cables were staged for use during the plant cooldown for the September 12 refueling outage, in accordance with Plant Engineering Procedure PEP-0239, "Performance Monitoring Program for Residual Heat Removal Heat Exchangers E12-EB001A and E12-EB001C (Div I)," Revision 1. However, blocking the water tight door open was not addressed in the procedure, nor could the licensee produce any documentation that evaluated the condition.

The test cables were promptly rolled back and the water tight door closed. The door had been open from August 11 through August 19. CR 97-1231 was initiated to enter the problem into the licensee's corrective action program. The licensee's preliminary investigation revealed that the operators had authorized the door to be open on the basis that it was a fire door. They had not realized that the door also provided flood protection. Drawings detailing plant door functions were provided to the operators on August 20. Engineering indicated that a database was being developed to show door, hatch and penetration functions as a long term corrective action. The licensee initiated a past operability assessment and a reportability determination.

Failure to adequately translate the design basis requirement to maintain closure of the water-tight doors into procedures is a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (50-458/97013-06).

c. Conclusions

The licensee failed to properly consider the design basis of the RHR Pump Room A water tight door when the door was blocked open to stage instrument cabling for thermal performance testing of the RHR heat exchangers during the September 12, refueling outage. A violation was identified for failure to translate the design basis into procedures.

M1.7 Failure to Meet Surveillance Program Requirement

a. Inspection Scope (61726)

Following a fire in a control box on Diesel Fire Pump A, the inspectors questioned what activities preceded the event to determine a possible cause and to verify that regulatory requirements were being met.

b. Observations and Findings

On August 21, 1997, the inspectors responded to a fire announcement that indicated that there was a fire in diesel fire pump Room A. Upon arrival, the inspectors noted that the operator had extinguished the fire with a portable fire extinguisher. A blocking diode in a control box mounted on Diesel Fire Pump A engine had burned. The inspectors questioned what evolution was in progress at the time of the fire. The operator was conducting an annual fire pump functional test in accordance with Procedure STP-251-3602, "Fire Pump Functional Test," Revision 9.

Upon reviewing the previous steps performed by the operator, the inspectors noted that Section 7.2.15, the sequential cranking test, had unexpected results recorded. In this test, the diesel was disabled from starting and it was allowed to crank 6 times for 15 seconds each with a 15 second rest. Each successive crank was to be alternated between the two batteries. On August 21, only one battery supplied power for all 6 cranks. This was unexpected and abnormal. The operator stated that he questioned the system engineer about this problem and understood the engineer to instruct him to proceed on, because the procedure was a new revision and the engineer needed to know if there were any other problems with the procedure. The operator proceeded with the problem unresolved and without obtaining Shift Superintendent or Control Room Supervisor direction, as required by Administrative Procedure ADM-0015, "Station Surveillance Test Program," Revision 18, Section 8.9.

Failure to immediately notify the Shift Superintendent or Control Room Supervisor that a problem was encountered during a surveillance procedure is a violation of TS 5.4.1.a (50-458/97013-07) and procedure ADM-0015.

The licensee investigated the cause of the burned diode and found that Procedure STP-251-3602 inappropriately directed the positive cable to be lifted from one battery to simulate a failed battery without disconnecting the battery charger. When the diesel fire pump attempted to start, it resulted in high current in the starting and charging circuits, thus overheating the blocking diode. The diode was replaced and the procedure was corrected to require both the battery charger and the battery to be disconnected. An operational retest was performed successfully.

c. Conclusions

While conducting operational testing of the fire pumps, test personnel failed to obtain the proper approvals to proceed after obtaining unexpected results for the sequential cranking test. A violation was identified for failure to comply with the surveillance test program procedure.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Weld Failure on the Division II EDG Intake Air Adapter

a. Inspection Scope (62707, 37551)

The inspectors reviewed CR 97-1155 and observed the licensee's actions in response to a weld failure on the Division II EDG intake air adapter that occurred during a 24-hour surveillance run.

b. Observations and Findings

On August 6, 1997, the outboard vertical weld failed on the carbon steel air adapter located on the inlet (bottom) of the intake air aftercooler. This occurred approximately 2 hours into the 24-hour operability run of the Division II EDG, which was being performed in accordance with Procedure STP-309-0612, "Division II Diesel Generator 24 Hour Run." The failure was a crack that ran along the weld for about 1/2 of the vertical weld length (5 inches). During the last hour of the run, the inspectors noted that, although a small amount of air escaped through the crack, it was not enough to affect combustion air pressure or cause any significant increase in fuel consumption. The 24-hour run was completed satisfactorily.

The licensee indicated that this weld cracked in the same location in 1989 (CR 89-0173) and again in 1990 (CR 90-0752). The other 3 sides of the weld attaching the adapter plate did not crack at any time and the crack observed on

August 6 was in the vicinity of the previous cracks, even though a doubler plate was installed to facilitate a larger weld on that side. The inspectors noted that the Division I EDG has not had this problem.

Plant Engineering, with support from Design Engineering, declared the EDG operable on the basis that the crack would not propagate any further and the added fuel consumption that might occur would be well within the fuel storage capacity margin. The engineers stated that the crack was monitored during the run and for the last 15 hours there was no sign of growth. In addition, the remaining weld attaching the adapter had sufficient strength to withstand the design loads. This position appeared reasonable to the inspectors for the short term until a repair could be made. On August 8, the weld defect was ground out and the weld was repaired in accordance with the information contained in the disposition in CR 90-0752 and MAI 312979. This was the interim disposition for CR 97-1155 until a long term repair could be implemented. The licensee informed the inspectors that engineering was evaluating the best course of action to prevent a recurrence of the failure. As of the end of the inspection period the licensee was considering replacing the entire adapter to preclude any resident repair stresses.

c. Conclusions

The licensee's actions in response to the repeated failures of the Division II EDG intake air adapter weld were appropriate to the circumstances.

M2.2 Lubrication of Safety-Related Motors

a. Inspection Scope (62707)

During the plant tours described in Section O1.1 of this report, the inspectors observed the lubrication of selected safety-related motors.

b. Observations and Findings

The inspectors noted that, in general, safety-related motors were properly lubricated. However, on August 6, 1997, the inspectors found excessive grease inside the motor casing of the SGTS fan motors. The B SGTS fan motor had grease only on the bell cap of the motor, but the A SGTS has grease on the motor windings as well. This as-found condition indicated that maintenance personnel had overgreased these motor bearings. The inspector notified the shift supervisor and CR 97-1167 was initiated to enter this item into the licensee's corrective action program.

The licensee performed operability assessments of the as-found condition of the SGTS fan motors. The licensee noted that although the motors were degraded, the system remained operable. However, the inspectors noted that the existence of the grease could affect the cooling of the motor windings and the long term life expectancy of the motors. In addition, this issue indicated that maintenance personnel attention to detail required improvement. The licensee noted that a similar CR was written concerning overgreasing of motors had been addressed over 2 years previously.

The licensee's corrective actions included: (1) planning to install relief plugs for the grease on safety-related motors, (2) calculating the proper amount of grease using vendor instructions and (3) evaluating changes to equipment qualification records for the frequency of lubricating the motor bearings.

c. Conclusions

Maintenance personnel overgreased the motor bearings for the SGTS, such that the life of the motor windings would be affected. A similar issue was identified approximately two years earlier. The licensee responded to this issue appropriately.

M8.1 (Closed) LER 50-458/96-014: missed surveillances due to human errors. This event was addressed in Special NRC Inspection Report 50-458/96-026, Enforcement Action 96-329 and the subsequent Notice of Violation dated November 7, 1996. Six violations were identified, constituting a Severity Level III problem. These violations are being tracked separately and will be closed during a future inspection when the licensee's corrective actions are essentially completed and evaluated for effectiveness. The LER was timely, accurate and adequately described the problems.

M8.2 (Closed) LER 50-458/96-015: inadvertent bumping of recently installed power supply fuse resulting in isolation valve closure. This event was addressed in NRC Inspection Report 50-458/96-015. No violations or deviations were identified; however, the inspection report stated that the inspectors would evaluate the licensee's corrective actions during the closure review of this LER.

The inspectors found that the licensee promptly attached caution labels over the power supply fuses in question, plus the other similar fuses in the control room. In addition, safety tape was attached to the adjacent floor of each of the fuses. Plant staff members questioned by the inspectors were aware of the fuses and of the care that must be taken, demonstrating that plant staff was informed as described in the LER. MAI 311059 was written to install plastic covers over the fuses and was due for completion in September 1997.

The LER was timely, accurate and adequately described the problem. The corrective actions were appropriate to the circumstances.

III. Engineering

E1 Conduct of Engineering

E1.1 Engineering Identified Inadequate Battery Surveillance Requirement

a. Inspection Scope (37551, 61726)

The inspectors reviewed the licensee's actions in response to CR 97-1079 and CR 97-1111, documenting that design engineering identified a nonconservative discrepancy in the specified test loads for the Division III battery service discharge surveillance test.

b. Observations and Findings

On July 24, 1997, the licensee's design engineers were in the process of resolving inconsistencies noted in the standard methodologies employed in determining the design basis load profiles of the safety-related batteries. The engineers identified a problem with the Division III battery, in that the load profile specified for the battery service test of TS Surveillance Requirement 3.8.4.7 was nonconservative. The values specified in the TRM were ≥53.6 amperes for the first 60 seconds and ≥15.8 amperes for the next 119 minutes. These values were used for all previous tests. The revised values were calculated to be ≥84.24 amperes and ≥16.11 amperes respectively. In addition, the revised calculation changed the battery size, such that the 80 percent minimum capacity specified in TS Surveillance Requirement 3.8.4.8 became nonconservative. The minimum capacity for the presently installed Division III battery was 91 percent.

The primary cause for this problem was that the original vendor-supplied calculation for the Division III battery duty cycle failed to consider momentary loads such as inrush, motor starting currents and plant-specific cable lengths. The licensee informed the inspectors that inconsistencies were resolved previously in 1996 on the Division I and II batteries and there were no nonconservative values indicated by the revised calculations. The licensee identified the errors in the calculations for the Division III battery as a result of the corrective actions they initiated for the errors identified in the calculations for the Division I and II batteries.

With the plant operating at full power, the operators declared the Division III battery inoperable. The limiting action required by TS 3.8.4.B was to declare the HPCS system inoperable, which allowed 14 days for restoration or shut down. However, within 2 hours, the Shift Superintendent decided to shut down in response to increasing drywell unidentified leakage as described in Section O2.1 above.

The licensee had no reason to believe the battery capacity was near or below the 91 percent value. Capacity discharge test results on June 12, 1994, were

105.9 percent. On July 28, 1997, a battery service discharge test was completed using the higher calculated minimum loads. The inspectors reviewed the completed test data and found the results to be satisfactory.

For corrective action, the licensee updated the TRM, the UFSAR and the battery service discharge test procedure with the correct battery profile and acceptance criteria. In addition, the engineering calculation procedure was revised to provide guidance to ensure that the basis for calculation assumptions was provided within the calculation.

This issue is not safety significant, because the July 28 battery service discharge test demonstrated that the battery was capable of performing its intended safety function from the time the battery was replaced in 1994. The licensee was reviewing test results prior to 1994 to determine past performance capability. The inspectors concluded that the licensee had taken good corrective action in response to the errors in the calculations for the Divisions I and II batteries.

c. Conclusions

The design engineers demonstrated good attention to detail in identifying nonconservative values in the design basis for Division III battery load profiles.

E8 Miscellaneous Engineering Issues (92700)

E8.1 (Closed) LER 50-458/96-010: reactor safety limit minimum critical power ratio (MCPR) calculation found nonconservative. During the core design work for Grand Gulf Nuclear Station, GE calculated a value for the safety limit MCPR at greater than the GE11 fuel generic value of 1.07. River Bend personnel were informed of this by Grand Gulf personnel, because of plant similarities. River Bend also had GE11 fuel. The LER provided a detailed explanation of the root causes and reported that the safety limit MCPR should have been 1.10 in lieu of 1.07 specified in TS 2.1.1.2. The safety significance of this discrepancy is that if the plant had operated at the core operating limit, the safety limit could have been challenged during anticipated operational occurrences. However, the licensee demonstrated to the inspectors and indicated in the LER, that the plant was operated with sufficient margin during the period the specified safety limit MCPR was 1.07, which was the first few months of Fuel Cycle 7. Therefore, there would not have been a challenge to the safety limit and the correctly calculated MCPR was not violated. The inspectors concluded that there were no licensee violations of regulatory requirements.

The licensee promptly implemented administrative limits on reactor operating parameters to ensure that the safety limit MCPR would not be challenged. Subsequently, in August 1996, the licensee revised the Core Operating Limits Report to reflect the corrected safety limit MCPR. In November 1996, the licensee submitted a TS change to reflect the new values. As described in the LER, GE implemented comprehensive corrective actions to prevent a recurrence and issued a 10 CFR Part 21 notification.

IV. Plant Support

P7 Quality Assurance in EP Activities

P7.1 Conduct of Pager Test Augmentation Drills

a. Inspection Scope (71750)

The inspectors reviewed the licensee's actions in response to CR 97-1204, where an emergency response organization team's participation was poor during an augmentation pager drill.

b. Observations and Findings

During an emergency preparedness program audit, quality assurance observed that an after-hours augmentation drill had not been performed in several years. Quality assurance requested that this drill be performed to test the response of the on-call emergency response organization team.

The licensee configured the automated call-out system such that it would only address the on-call team. Normally, if there was not a response from an on-call team member, the system would telephone a member from one of the other duty teams. The intent of the drill was to determine what percentage of the team would actually respond and to determine how quickly the emergency response facilities could be staffed. Using this modified process, the drill was conducted on August 12, 1997, at 7 p.m. Only 27 of the 74 on-call emergency team reported to their assigned facilities. The licensee initiated a condition report to investigate this situation.

Some hardware problems were identified. Two pagers were found to be broken and were replaced. A number of people did not respond to the automatic call-out properly. These included not answering "yes" to all of the prompts, pressing the wrong key, incorrectly answering the questions and hanging up before all the message was completed. These problems were considered training issues since they indicated either improper technique or lack of understanding on the operation of the automatic call-out system. The remaining problems were personnel performance issues. These included people having their pagers turned off, not realizing they were on call, or when they heard it was a drill, they did not listen to the message to determine what response was required.

Following the August 12 drill, the licensee distributed a notice containing expectations for emergency response organization members carrying pagers.

Letters were sent to supervisors requesting that they discuss these expectations, document the discussion and forward the documentation to emergency planning. Emergency planning staff contacted specific team members to discuss the appropriate responses and expectations of what should have occurred during the drill.

On August 18, 1997, at 7 p.m., the licensee conducted a second after-hours augmentation drill. The results were much better than the August 12 drill. All facilities were staffed with minimum staffing within the goals stated in the licensee's emergency plan with the exception of the emergency operations facility. One minimum staffing position was not filled due to a problem with the individual's pager.

The inspectors recognized that the method used to conduct the drill was not consistent with the routine way the licensee would call out emergency response personnel. As such, emergency response organization personnel from other teams were not called when the on-call team members did not respond. The licensee recognized that this problem was generic and promptly initiated corrective actions following the identification of the problems. Additional pager drills and augmentation drills were scheduled. The corrective actions were still in process at the end of the inspection period.

The staff augmentation problem identified by the licensee was considered to be a matter that required further inspection because corrective actions and an evaluation of their effectiveness were pending. As such, the review of licensee corrective actions is an inspection followup item (IFI) (50-458/97013-08).

c. Conclusions

Conduct of after-hours, augmentation drills resulted in licensee-identified problems related to on-call emergency team response. Corrective actions were promptly initiated. An IFI was identified to review the effectiveness of corrective actions during a subsequent inspection.

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. During backshift inspections, the inspectors noted that the protected area was properly illuminated, especially in areas where temporary equipment was brought in.

F1 Control of Fire Protection Activities

F1.1 Inadequate Control of Transient Combustibles

a. Inspection Scope (71750)

The inspectors observed the licensee's fire protection controls during fuel receipt inspections, as discussed in Section O1.3 of this report.

b. Observations and Findings

During new fuel receipt inspections, the licensee had to bring the fuel assembly and fuel channels packing boxes into the vital area. These packing boxes were constructed from untreated wood. Fire Protection Procedure FPP-0040 Section 5.2.4 was written such that the use of untreated wood was recognized and stated that packing materials shall not be left unattended during lunch breaks, shift changes, or similar periods unless stored in approved containers. 10 CFR Part 50, Appendix R, contains similar requirements.

On August 7, 1997, the inspectors noted that the truck bay of the 95 foot elevation of the fuel building contained several wooden fuel shipping containers that had apparently been there for several shifts. The licensee stated that this was an approved combustible storage area, thus Section 5.2.4 of FPP-0040 was not applicable. The inspectors reviewed the licensee's listing of designated combustible storage areas and determined that this practice was satisfactory.

However, the inspectors noted that the wooden packing boxes for the fuel channels had been left at the 113 foot elevation of the fuel building. This material was left unattended during breaks and overnight. This condition existed from July 30 through August 7, 1997. This area was not a combustible storage area. The reactor engineer stated that they interpreted the requirements for storage of combustible material as not applicable because the boxes were not empty. The inspectors discussed these observations with the fire protection engineer, who stated that the licensee's procedures did not support the reactor engineer's interpretation. The fire protection engineer initiated CR 97-1164 to enter this item into the licensee's corrective action program. Leaving combustible materials unattended in safety-related areas is a violation of Procedure FPP-0040 and an additional example of a violation of TS 5.4.1.d (50-458/97013-07).

The licensee's investigation revealed that leaving fuel channel shipping boxes unattended was the normal practice during previous fuel cycles. The inspector noted that because leaving combustible materials unattended during new fuel receipt inspection activities was a common practice, it was indicative that the receipt inspection team was not appropriately familiar with fire protection requirements. The recent NRC fire protection functional inspection identified similar concerns with combustible material controls. Licensee management acknowledged the inspectors comments.

c. Conclusions

A violation was identified for leaving untreated wood unattended during fuel receipt inspection activities. Fuel receipt inspection personnel were not appropriately trained on fire protection requirements. This issue was similar to a finding of the recent NRC fire protection functional inspection.

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 September 8, 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
J. R. Douet, Manager, Maintenance
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
A. D. Wells, Superintendent, Radiation Control

INSPECTION PROCEDURES (IP) USED

IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Followup - Operations

ITEMS OPENED AND CLOSED

Opened

50-458/97013-01	VIO	Failure to follow protective tagout restoration procedure (Section O1.2)
50-458/97013-03	VIO	Failure to evaluate SRV lift prior to startup (Section O2.2)
50-458/97013-05	VIO	Failure to implement foreign material exclusion near suppression pool (Section M1.4)

50-458/97013-06	VIO	Failure to maintain ECCS room water tight door closed (Section M1.6)
50-458/97013-07	VIO	Failure to comply with surveillance program requirement (Section M1.7) and failure to control combustibles in fuel building (Section F1.1)
50-458/97013-08	IFI	Followup on pager test augmentation drills (Section P7.1)

Closed

50-458/97006-01	VIO	Failure to establish adequate controls over overtime (Section O8.2)
50-458/96-010	LER	MCPR calculations found nonconservative (Section E8.1)
50-458/96-014	LER	Missed surveillances (Section M8.1)
50-458/96-015	LER	Bumping of power supply fuse (Section M8.2)
50-458/96-016	LER	Chiller timer defeat switch left in test (Section O8.1)

Opened and Closed

50-458/97013-02	NCV	Failure to maintain adequate fuel handling procedure (Section O1.3)
50-458/97013-04	NCV	Performing prohibited EDG inspections at power (Section M1.3)

LIST OF ACRONYMS USED

CR	condition report
ECCS	emergency core cooling system
EDG	emergency diesel generator
FIRS	fuel integrity and reactor subcriticality
FRC	Facility Review Committee
GE	General Electric Company
gpm	gallons per minute
IFI	inspection followup item
IP	inspection procedure
LCO	limiting condition for operation
LER	licensee event report
MAI	maintenance action item
MCPR	minimum critical power ratio
NCV	noncited violation
PDR	Public Document Room
PM	preventive maintenance
psig	pounds per square inch gauge
RHR	residual heat removal
SERT	Significant Event Response Team
SGTS	standby gas treatment system
SRV	safety relief valve
SSW	standby service water
TRM	Technical Requirements Manual
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
VIO	violation