APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-458/90-29 Operating License: NPF-47

Docket: 50-458

Licensee: Gulf States Utilities Company (GSU)
P.O. Box 220
St. Francisville, Louisiana 70775

Facility Name: River Bend Station (RBS)

Inspection At: RBS, St. Francisville, Louisiana

Inspection Conducted: October 17 through November 27, 1990

Inspectors: E. J. Ford, Senior Resident Inspector
D. P. Loveless, Resident Inspector
D. A. Powers, Reactor Engineer

Approved: P. H. Harrell, Chief, Project Section C 12/26/90 Date

Inspection Summary

Inspection Conducted October 17 through November 27, 1990 (Report 50-458/90-29)

Areas Inspected: Routine, unannounced inspection of onsite followup of events, operational safety verification, maintenance and surveillance observations, installation and testing of modifications, engineered safety feature system walkdown, followup of regional requests, and followup of previously identified items.

Results:

- At the end of this inspection period, the licensee had essentially completed an approximately 2-month refueling outage, with an absence of the kind and number of problems experienced during the previous refueling outage (RF-2), as a result of management implementation of lessons learned from RF-2.

- Three new categories of problems experienced during the current outage, while not as severe as the problems of the previous outage nor of the same type, are cause for concern in that they indicate a lack of attention to detail by operators performing operational functions, a lack of respect for radiological barriers by plant personnel, and control of modifications to the plant. Examples of operator inattention to detail are discussed in paragraphs 3.b, 3.c, 3.d, 3.g, and 3.h. Paragraph 4.d provides further information on problems involving radiological barriers.

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- ESF actuations caused by modification implementation were experienced. The reason appeared to be that the licensee had not designated a department within their organization to review the impact on plant systems during installation of modifications (paragraph 7).

- Although there are no Technical Specification requirements for suppression pool chemistry, the licensee made voluntary efforts to clean and purify suppression pool water.

- The inspector noted that an 18-month emergency core cooling system test, although complicated and requiring rapid response, was well controlled and had extensive management involvement. The licensee's program for implementation of individual surveillance procedures appeared to be strong.

- The licensee formed an attrition task force in response to concerns regarding personnel losses. This issue is further discussed in paragraph 4.b.

Open Items: During this inspection period, the inspection findings listed below were identified:

- Two violations were identified.

  Violation 458/9029-02: Inadequate posting and barricade of a very high radiation area on the 85-foot elevation of the drywell (paragraph 4.d).

  Violation 458/9029-04: Five fuel bundles were misoriented when placed in the core (paragraph 9.a.(8)).

- One unresolved item was identified.

  Unresolved Item 458/9029-03: Review of three engineered safety feature actuations caused by implementation of modifications in the plant (paragraph 7).

- Three inspector followup items were identified:

  Inspector Followup Item 458/9029-01: Review the application of insulation and the operational conditions surrounding the fire on the Division I diesel generator exhaust (paragraph 3.a).

  Inspector Followup Item 458/9029-05: Review the licensee's plans for replacement of three Rosemount transmitters (paragraph 9.b).

  Inspector Followup Item 458/9029-06: Inspection of the feedwater nozzle to safe-end weld indication (paragraph 9.c).

Note: Acronyms and initialisms used in this report are defined in an alphabetical listing in an attachment at the end of this report.

DETAILS

1. Licensee Personnel Contacted

R. E. Barnes, Supervisor, Codes and Standards
R. A. Blose, Supervisor, Instrumentation & Controls
#T. D. Burnett, Jr., Chemistry Foreman
#E. M. Cargill, Director, Radiation Programs
*#J. W. Cook, Technical Assistant
*#T. C. Crouse, Manager, Administration
*N. L. Curran, Site Representative, Cajun
@*#J. C. Deddens, Senior Vice President, River Bend Nuclear Group
D. R. Derbonne, Assistant Plant Manager, Maintenance
#S. V. Desai, Senior ISEG Engineer
L. L. Dietrich, Supervisor, Nuclear Licensing
#L. A. England, Director, Nuclear Licensing
*#C. L. Fantacci, Supervisor, Radiological Engineering
P. E. Freehill, Assistant Plant Manager, Outage
@*#P. D. Graham, Plant Manager
*J. R. Hamilton, Director, Design Engineering
*#G. K. Henry, Director, Quality Assurance Operations
#K. C. Hodges, Supervisor, Chemistry
*T. L. Hunt, Senior ISEG Engineer
#D. E. Jernigan, Supervisor, General Maintenance
#L. G. Johnson, Site Representative, Cajun
*#G. R. Kimmell, Director, Quality Services
#L. A. Leatherwood, Supervisor, Core Analysis
*#D. N. Lorfing, Supervisor, Nuclear Licensing
I. M. Malik, Supervisor, Quality Operations
J. F. Mead, Supervisor, Electrical Design
@#W. H. Odell, Manager, Oversight
R. L. Roberts, Supervisor, Electrical Maintenance
@*M. F. Sankovich, Manager, Engineering
*#J. P. Schippert, Assistant Plant Manager, Operations, Radwaste and Chemistry
#J. E. Spivey, Quality Assurance Engineer
*#K. E. Suhrke, General Manager, Engineering and Administration
J. E. Venable, Assistant Operations Supervisor
#M. L. Wittenburg, Nuclear Fuels Engineer
S. L. Woody, Supervisor, Nuclear Security
#G. S. Young, Supervisor, Reactor Engineering

NRC Personnel

#R. E. Baer, Senior Reactor Health Physicist
@G. L. Constable, Chief, Technical Support Section
@#E. J. Ford, Senior Resident Inspector
@P. H. Harrell, Chief, Project Section C
*#D. P. Loveless, Resident Inspector
#D. A. Powers, Reactor Inspector

The inspectors also interviewed additional personnel during this inspection period.

#Denotes those persons that attended the exit interview conducted on November 16, 1990, to discuss the findings of the review of the licensee's fuel problems (paragraph 9.a).

*Denotes those persons that attended the exit interview conducted on November 27, 1990, to discuss the overall results of this inspection.

@Denotes attendance at the performance review provided on November 19, 1990 (paragraph 11).

2. Plant Status

At the beginning of this inspection period, the reactor was shut down for refueling, and the licensee had completed approximately 153 steps out of approximately 1100 needed to complete fuel movement.

The licensee completed the refueling, replaced 24 control blades, replaced 16 hydraulic control units, and sipped 66 fuel assemblies to identify leaking fuel. On November 20, 1990, the reactor studs were tensioned, placing the reactor in Mode 4.

At the end of this inspection period, the reactor was in cold shutdown (Mode 4) with the new core loaded and preparations in progress to restart the unit.

3. Onsite Followup of Plant Events (93702)

a. Fire in the EDG Exhaust Stack

At 7:08 a.m. (CDT) on October 20, 1990, the licensee discovered a fire on the Division II EDG exhaust stack. At 7:10 a.m., the fire was reported out. The fire reflashed once and was rapidly extinguished.

The fire was apparently caused by hot fumes from the exhaust manifold expansion joint impacting on the paper jacket of the insulation on the stack. The paper began to burn and was supplied air by the normal building ventilation fans. The EDG had been running in idle for an extended period, which provided a richer than normal exhaust mixture. The licensee believed that this was a contributing factor to the fire.

The inspector questioned the use of paper-jacketed insulation for this specific application and whether operators should have been more cautious during an extended run of the EDG at idle speed.

The licensee has removed the paper jacket up to 6 feet above the expansion joint and replaced the insulation with one made of stainless steel; therefore, the fire hazard does not currently exist. Additionally, the licensee reconfigured the new insulation to remove the gas trap that had allowed hot exhaust fumes to accumulate around the expansion joint. At the end of the inspection period, the inspector was not aware of why paper-jacketed insulation had been used in this application.

This item will be reviewed further by the inspector and will be tracked as an inspector followup item (458/9029-01).

b. EDG Synchronized to Grid Out of Phase

On October 21, 1990, the licensee was conducting postmaintenance testing of the Division II EDG (1EGS*EG1B) following scheduled vendor inspections.

The licensee was preparing to fully restore the Division II electrical system to an operable status. A reactor operator attempted to synchronize the EDG to the Division II vital switchgear (ENS*SWG1B) and incorrectly closed the generator output breaker when the ac signal was out of phase with the grid. The normal feeder breaker to the vital bus tripped, leaving the EDG tied to the vital boards. The licensee reported that, after a surge estimated at approximately 6000 kW, the EDG picked up the Division II load of approximately 1000 kW and ran for approximately 10 minutes with no operational impact on the plant. The licensee initiated CR 90-0976 to document the event.

The inspectors discussed the event with several responsible licensee personnel and determined that preliminary searches did not disclose any abnormal mechanical or electrical damage. The surge suppressor (selenium rectifier) that protects the silicon control rectifiers in the exciter circuitry was destroyed in performing its normal suppression function. The licensee replaced the suppressor and conducted further testing on the generator and associated electrical components. The onsite vendor representative assisted the licensee with their investigation.

The inspectors conducted a walkdown of the EDG and held discussions with testing personnel present. The licensee performed a mechanical inspection of the EDG including the crankshaft through the NO. 8 cylinder, the bearing between the NO. 7 and 8 cylinders, the gear train, the main governor drive coupling, the diesel base, the rotor shaft, the engine grid grout, the generator flywheel coupling bolts, and the foundation bolts. Additionally, electrical inspections were performed that included generator stator resistance checks, rotating element rolling impedance and voltage drop tests, excitation cabinet checks, and relay actuations.

No damage was identified, other than to the selenium rectifier discussed above. The licensee successfully conducted postmaintenance and the TS-required surveillance tests, and returned the EDG to service.

c. Loss of Shutdown Cooling

On November 4, 1990, the licensee experienced a loss of shutdown cooling for approximately 6 minutes. The loss occurred when RHR Pump B tripped on low suction pressure as a result of its suction flow being isolated by Valve 1SFC*MOV-121 (spent fuel pool cooling to RHR isolation) inadvertently closing. The operators took action to have the problem corrected, reopen the valve, and restart the pump. The reactor and upper cavity water temperatures exhibited no change and the cavity level decreased approximately 1/4 inch during the event.

At the time of the event, the plant was in the refueling mode, with greater than the TS-required 23 feet of water in the upper cavity. RHR was lined up in the alternate shutdown cooling mode (spent fuel pool cooling assist) to support outage activities. Electricians were installing a modification that added additional indication to the main control panels for nuclear steam supply shutoff system actuations.

Previous research by engineering personnel noted that, during this work, a Division I half main steam line isolation, along with MSL drain, BOP, RHR, RWCU, and RWS isolations, would occur. This information was documented in the modification request and presented to the shift supervisor. Based on this information, the operators took action, prior to the planned modification, to prevent the RWCU system isolation. Division 1 RHR, MSL, MSL drains, and RWS systems were out of service at the time. However, the BOP isolation was overlooked. During the work, the anticipated BOP isolation occurred and closed Valve 1SFC*MOV-121.

The licensee initiated CR 90-1065 and the preliminary findings indicated that the shift supervisor should have been cognizant of the potential ESF actuation and prevented the BOP isolation prior to authorizing the work.

This event will be reviewed further during routine followup of the LER to be issued by the licensee.

d. Loss of Shutdown Cooling

On November 9, 1990, with the plant in the refueling mode, the licensee experienced a Division I isolation and received an RPS half-scram signal. The signals occurred when an operator inadvertently deenergized the load center supplying the RPS B MG set. The isolation caused a loss of suction flow to RHR Pump B and a loss of the RWCU system. All isolations occurred, as expected, for the current plant conditions, and all systems were restored to their previous configuration with no abnormalities. Shutdown cooling was lost for approximately 6 minutes. No change in refueling pool water temperature or level was noted.

At the time of the event, the operator was restoring a 480-volt load center (NJS-LDC1D) to its normal power supply through Breaker NJS-ACB062. This breaker, from the low side of the supply transformer, was closed and the cross-tie breaker (NJS-ACB042) was opened. However, the high-side breaker (NPS-ACB033) for the supply transformer was open, causing a loss of power to the load center and, subsequently, to the RPS B MG set.

Also, at the time of the event, the plant was lined up for shutdown cooling utilizing Train B of RHR in the fuel pool cooling assist mode. This lineup included an RHR suction path through the spent fuel cooling system. The Division I isolation caused Valve SFC*MOV121 to close, interrupting the suction path to the Division II RHR pump. The plant had alternate decay heat removal available through the control rod drive hydraulic system.

The licensee documented the event in CR 90-1096 and is currently reviewing the event. This event will be reviewed further during routine followup of the LER to be issued by the licensee.

e. Inadvertent Start of an EDG

On November 10, 1990, the plant experienced an ESF actuation when the Division III HPCS EDG inadvertently received an emergency start signal. The diesel ran for approximately 3 minutes unloaded. All systems functioned as expected.

At the time of the actuation, a recorder was being installed on the EDG start relay to provide an accurate start time for surveillance testing. The procedure called for placing the recorder across relay Contacts 1 and 2. However, the terminal points were not labeled and the technician proceeded to connect the recorder across Wires 1 and 2, which were connected to Terminals 1 and 13. While connecting the recorder to Terminal 13, which goes to the negative side of the relay, a screwdriver temporarily contacted Terminal 11. Terminal 11 is connected to the positive supply. This caused the K-1 relay to energize and start the Division III EDG.

The licensee initiated CR 90-1097 and an investigation of the event is ongoing. The inspector will review licensee actions during routine followup of the LER to be issued by the licensee.

f. Inadvertent Trip of the EDG Output Breaker

On November 19, 1990, the Division I EDG output breaker tripped during its required 24-hour run. The generator had been fully loaded and tied to the grid. No electrical transient occurred, and the diesel remained running.

At the time of the event, the licensee was performing a retest of the LPCS system. This followed a failure of the system during the

Division I, 18-month ECCS testing. The engineers performing the test had evaluated the retest and failed to realize that the testing activities would cause EDG 1A output breaker to open. Additionally, the RHR A system realigned from the shutdown cooling mode to the low pressure coolant injection mode, but it did not inject any water.

All systems operated as expected for the condition. The inspectors will review this event during routine followup of the LER to be issued by the licensee.

g. Inadvertent Isolation of Division II Valves

On November 19, 1990, an SRO inadvertently deenergized the B train, 120-Vac vital distribution panel. This caused an isolation of Division II valves and dampers for the various systems in service. These included RHR reject to radwaste, containment drains, and various HVAC systems.

At the time of the event, operations personnel were installing a clearance on the RPS Train B alternate supply breaker to take the breaker out of service for maintenance. Drawing EE-9PZ-7 was utilized to write the clearance request. However, this drawing was red-lined in 1989 to reflect a change in cubicles between Breaker 1RPS*XRC10B1 (power supply for the RPS Train B power line conditioner) and Breaker 1SCM*XRC14B1 (power supply for the line conditioner on the 120-Vac distribution panel). The licensee's drawing control program only makes red-lined changes to the control room drawings. It was the responsibility of individuals utilizing controlled drawings to check the control room copy for any red-lined changes prior to using the drawing for safety-related work. The drawing utilized was a shop drawing and had not been checked for these red-lined changes.

This error could have been corrected by the individual installing the tag, who stated that he failed to notice that the cubicle number was wrong. Additionally, the SRO installing the clearance should have identified the error. However, he stated that the identification tags were not completely clear, and the designations were very similar, so he utilized the cubicle number to determine which breaker to open. As stated before, this cubicle number was wrong, and opening the breaker caused the ESF actuation.

The licensee initiated CR 90-1154 to document the event and initiate corrective action. This item will be reviewed by Region IV inspectors and documented in NRC Inspection Report 50-458/90-33.

h. Inadvertent Realignment of HPCS Suction Valves

On November 21, 1990, the HPCS system automatically swapped its suction from the CST to the suppression pool on a high SP-level signal. The swapover included the opening of the SP suction valve

(E22*MOV-F015) and the closing of the CST suction valve (E22*MOV-F001). On November 20 operations personnel had raised the SP level to 20.4 feet per STP-057-3603, "Drywell Bypass Leakage Rate Test." The setpoint for the swap over is 20 feet 5 inches. The licensee hypothesized that the level instrumentation was so close to the setpoint that a slight perturbation caused the event.

Operators stated that the suction swap was simply overlooked in preparation for the testing. A procedure change was initiated to caution against such an event during future outages. The SP is the safety-related source of water to the system, and operations personnel decided not to realign the HPCS system until the drywell leakage testing was complete.

The inspectors will review this event during routine followup of the LER to be issued by the licensee.

Conclusions

The inspectors were concerned by the number of events occurring during this period, especially because of the large number of procedural and personnel errors. The types of events experienced indicated a lack of attention to details by personnel.

4. Operational Safety Verification (71707)

a. Routine Plant Observations

The inspectors toured the control room on a routine basis to observe operational activities, review and discuss plant status, and observe the operators in performance of their duties. The inspectors noted that, during times of heavy workloads in the control room, the shift supervisor continuously supported a slow controlled approach to evolutions and relieved the operators of the burden of outage schedule pressures.

The inspector noted, throughout this inspection period, a high level of licensee management presence in the plant. Specifically, the inspector noted the Plant Manager; Assistant Plant Manager for Operations, Radwaste, and Chemistry; Assistant Operations Supervisor; and Director of Radiation Programs in the plant with a high level of regularity.

Routine observations of safety system alignments were performed throughout the inspection period from both the control room indications and local position checks. No problems were noted with the alignments.

b. Attrition at the RBS

In response to concerns raised internally and externally about attrition, an attrition task force was formed to study the factors related to attrition. The task force provided the results of this study to the CEO, on October 23, 1990, itemizing nine areas where improvements might be achieved that could control the attrition rate. The recommendations provided by the task force have been either approved for implementation or are being reviewed for further action, study, or implementation. Those items approved for immediate implementation were assigned to a responsible manager to take the lead and develop/implement action plans. Some of these plans are continuing in nature and some are designed to address single issues.

c. SP Cleaning Activities

During routine tours, the inspector observed licensee actions to clean and purify the water in the SP. This program was designed in three phases. Phase 1 involved vacuuming the floor and cleaning of the sides of the SP. Phase 2 included filtering and deionization of the water utilizing a filter/demineralizer system. Phase 3 of the cleanup required divers to enter the pool, inspect for and remove foreign objects from the bottom of the pool, and inspect the ECCS strainers for integrity and foreign particle blockage.

On October 19, 1990, the licensee began Phase 1. Efforts were not successful in cleaning the outer wall because of poor equipment design. The effort in Phase 1 was stopped on November 5, 1990, when all accessible areas of the SP had been vacuumed and the majority of surface foreign objects had been removed.

Phase two was started on November 12, 1990. This effort utilized three trains of filter/demineralizer systems. At the beginning, the pool water had a turbidity reading of approximately 13 NTU, a radioactivity of approximately 6.5E-3 microcuries per milliliter, and a conductivity of approximately 12.5 microsiemens per centimeter. At the end of the Phase 2 effort, the turbidity had been reduced to 1.5 NTU, the radioactivity to 2.3E-4 microcuries per milliliter, and the conductivity to 2.5 microsiemens per centimeter. This was accomplished despite numerous operational activities which stirred, added, and drained water in the SP. At the end of the outage, the inspector noted, with a high-intensity underwater light, that the bottom of the suppression pool (20 feet) could be seen. Approximately 3.2 million gallons of water had been processed.

It should be noted that there are no requirements for suppression pool chemistry. However, this voluntary effort by the licensee will allow for better chemistry in the ECCS systems during routine testing, lower dose rates, and better ability to assess the ECCS strainers.

d. Review of RP Activities

Generally, the RP organization functioned well as a unit. The inspector noted that RP technicians were thorough and accurate in their preentry briefings. Entries made into VHRAs were well controlled, and stay times were set conservatively. Technicians did not hesitate to move dosimetry, add additional dosimetry, set alarms at conservative settings, or require additional precautions, as necessary, to protect the individuals entering high radiation areas.

However, on November 16, 1990, while entering a VHRA under RWP 90-3030 to observe licensee work practices, the inspector observed that the barrier with an attached sign stating "Danger - Very High Radiation Area" to the entrance was down. The rope was designed to be hooked over the stairway railing to block access to the 85-foot elevation of the drywell. Additionally, a flashing red light had been positioned at the entrance as a warning device. However, the batteries had worn and the intensity was such that the effectiveness was reduced. The inspector had passed the light before noting that the flashing light was present. This event was documented by the licensee on CR 90-1136.

Although the surveys, considered current at the time, did not show area radiation levels to be greater than 1000 mrem per hour, personnel had been removing shielding from the RCS and RWCU systems for 2 days. The licensee stated that RP personnel had not performed a new survey because the dose expenditure would be too high to perform interim surveys while the shielding was being removed. The inspector noted that preshielding surveys showed 18-inch dose rates that were greater than 1000 mrem per hour. Additionally, some 18-inch doses were greater than 2000 mrem per hour.

Following the event, the licensee performed a survey of the area, after all the shielding had been removed, and identified 18-inch dose rates greater than 1000 mrem per hour. In lieu of a current survey, it was conservative to assume that dose rates, in some areas, were such that a whole body dose greater than 1000 mrem could have been received in 1 hour. The inspector also noted that the most conservative survey had not been used to brief the individuals entering the subpile room for the work on the IRMs.

TS 6.12.2 requires that an area, where a dose of greater than 1000 mrem could be received in 1 hour, be provided with locked doors or, if no enclosure can reasonably be constructed, the area shall be roped off, conspicuously posted, and a flashing light activated as a warning device. Because the barrier was down, the entrance to the area was neither roped off nor conspicuously posted. This is a violation (458/9029-02).

During outage and preoutage work, individuals, on three occasions, entered high radiation areas either inadvertently or without the TS-required dosimetry. The three events were documented in the following CRs:

- CR 90-1077: Two contractor people entered a high radiation area without TS-required monitoring.

- CR 90-0890: Two contract workers entered a high radiation area without alarming dosimetry.

- CR 90-0804: An operator was observed in a high radiation area without the proper dosimetry and without knowing the dose rates in the area.

These events were reviewed by the NRC and documented in NRC Inspection Report 50-458/90-30. Prior to the outage, four other events occurred this year involving individuals inadvertently in high radiation areas. These are documented in CRs 90-0236, 90-0395, 90-0413, and 90-0576. Additionally, the NRC has documented a minor misuse of a magenta and yellow rope in NRC Inspection Report 50-458/90-13.

These events, in conjunction with the above described event, cause concern for the high radiation area controls and indicates that additional management attention is necessary in this area.

e. Verification of the Position of Containment Isolation Valves

During this inspection period, the inspector determined that a selected portion of containment isolation valves were lined up as required for fuel movement containment integrity. The specific valves reviewed were all the isolation valves inside containment. All penetrations were lined up as required by the SOP and were in good physical condition.

f. Review of Emergency Lighting

Appendix R to 10 CFR Part 50 requires that emergency lighting units, with at least an 8-hour battery supply, be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes, thereto.

To determine if the emergency lighting would perform in accordance with the above requirements, on November 7, 1990, the inspector requested the assistance of a licensed operator to operate selected emergency lights. Emergency lights were manually tested in the main control room, the stairwells for exiting from the front and rear of the main control room to the remote shutdown rooms, the corridors used to travel to the shutdown areas and the vital electrical rooms, and other appropriate areas in the control building. Also, lighting along the two most probable routes of travel to the turbine and auxiliary buildings were tested. All the lights operated satisfactorily, except for one light in Tunnel T at Elevation 123 near the operator frisking station. The accompanying operator promptly initiated an MWO to have the problem corrected. No further problems were noted.

g. Review of NRC Postings

The inspector provided copies of the current NRC Form 3, "Notice to Employees," dated October 1989, to the Supervisor, Nuclear Licensing and requested that present postings be replaced to comply with the requirements of 10 CFR Part 19.11. The inspector [illegible] that NRC Form 3 was displayed on controlled bulletin boards on each of the three floors of the services building. The licensee also maintains boards in three other locations on site.

The inspector verified that the requirements of 10 CFR Part 21.6 were satisfied at the first three locations. A licensee representative stated that these requirements were also met at the other site locations. The inspector noted that an out-of-date NRC Form 3 was displayed in an uncontrolled manner at the protected area entrance. The licensee committed to either update the posting or remove it. Additionally, the licensee replaced Part 21 postings with larger, easier-to-read postings. No further problems were noted.

Conclusions

Generally, the plant was in good material condition, management efforts in the plant were good, and operators were in control of plant evolutions. One exception was the violation identified with the radiological barrier. Additional management attention is needed in the control of radiological barriers.

5. Maintenance Observations (62703)

On November 16, 1990, the inspector watched a partial performance of the following MWOs:

MWO Number	Equipment
R 140139	1C51*K601H (IRM H)
R 140138	1C51*K601G (IRM G)
R 140136	1C51*K601E (IRM E)
R 140141	1C51*K600C (SRM C)
R 140142	1C51*K600D (SRM D)

Each of the listed MWOs required the technician to inspect the cable and connector of the associated detector for possible damage incurred during under-vessel maintenance to the control rod drive hydraulic control units, and to rework, as required, to restore the cable and/or connector to normal.

These MWOs were initiated following an RPS actuation, on October 27, 1990, while the plant was in the refueling mode, with the reactor depressurized and all control rods fully inserted. An RPS actuation signal was generated by an upscale spike on IRM Channels F and G (RPS Divisions II and I, respectively). All systems responded as expected, and the scram was reset.

The licensee had previously completed the replacement of 16 control rod drive mechanisms and was wetting down the underside of the reactor vessel with a 100-psig source of water when the event occurred. Instrument maintenance technicians found that both IRM channels had loose connectors and had filled with water. This water shorted the conductors in the connectors, together with the vibrations caused by the water spray, appeared to have caused the spikes.

The inspector noted that a half scram had been received on IRM Channel F on October 24, 1990. A review of both events prompted the licensee to initiate action to inspect other under-vessel connections.

The inspector observed the inspections of the above listed IRMs and SRMs. During the inspections, moisture was found inside the connector housings, housings were discovered to be loose, connectors were found to be loose, incorrect cable routings were found, and a pressure boundary fitting was found to be loose. Following the initial inspections of these five detectors, the licensee replanned the work and corrected the problems.

Following the rework, the inspector observed licensee performance of a pressure test on the SRM/IRM drive and shuttle tubes. The pressure test could not meet the acceptance criteria. The licensee received a memorandum from GE stating that the leak test was not mandatory and that any measurable leakage would only leak to zero pressure anyway. The memo stressed that the important parameter was that the volume was dry. GE recommended that a resistance check be performed between the detector sheath housing and the drive tube, and that the resistance should not be less than 10,000 ohms. In all cases, the SRM/IRM resistance checks exceeded this value with a recorded resistance of infinity.

The inspector also noted that the position indication probes to each hydraulic control unit had electrical connections in the vicinity of the problem detector connections. The inspector questioned the integrity of these connections that were in the same environment as the neutron monitoring connections. The licensee agreed to perform checks of all under-vessel instrumentation.

The inspector reviewed MWO R 144565 that checked the integrity of the insulation on the LPRM strings. All LPRMs exceeded the acceptance criteria of greater than 1 E9 ohms by measuring the detector-to-ground resistance with a 10-Vdc source. The results of these tests showed ranges from 1 E10 to 1 E12 ohms. Additionally, the control rod position indication was functionally tested during the normal stroking of the control rods. One PIP and one PIP connector were identified as being deficient out of 290 PIPs. These were documented under MWOs and replaced. All the TIP system tubing was verified intact by successful operation of the TIP system.

The effort produced by the licensee following the inadvertent scram signal indicated a good attention to safety and gave a better understanding of the integrity of instrumentation that could have been damaged as a result of the extensive work performed under the reactor vessel during the recent outage.

6. Surveillance Observations (61726)

a. Station Battery Testing

On November 11, 1990, the inspector observed the performance of STP-305-1100, "Battery Weekly Surveillance Test for Battery 1ENB*BAT01A," and STP-305-1101, "Battery Weekly Surveillance Test for Battery 1ENB*BAT01B." These surveillances test the batteries for appropriate voltage, test cell voltage, electrolyte level, and test cell electrolyte density and temperature. The inspector observed that the electricians were following the procedure, were familiar with the procedure and the equipment, and that they were qualified to perform the testing. Instrumentation was determined to be within calibration dates. All acceptance criteria of the test were met.

b. ADS System Testing

On November 14, 1990, the inspector observed the performance of STP-202-0201, "ADS Inhibit Switch Channel Functional Test." The ADS system actuation is expected to be inhibited during several classes of accidents. This surveillance tests the circuitry required to provide this function.

The inspector noted that the operators performing the test were knowledgeable of their procedure and were utilizing it throughout the test. Appropriate checks and approvals were made prior to performing the test and no work was being performed on the opposite train that could have prevented the actuation of the ADS system. It was determined that test instrumentation was in proper calibration. The system was restored to normal status and was double verified to be in its correct lineup.

The inspector verified that the procedure met the requirements of TS 4.3.3.1, Table 4.3.3.1-1, Items A.2.g and B.2.g and that all acceptance criteria of the test were met.

c. Manual Scram Test

On November 16, 1990, the inspector observed the performance of STP-508-0201, "Manual Scram Channel Functional Test." The inspector verified that the test met the criteria of TS 4.3.1.1, Table 4.3.1.1-1, Item 13.

The inspector verified that the surveillance was completed within its required frequency and independently verified that the system was returned to service properly. The test met all acceptance criteria.

d. ECCS Testing

On November 16, 1990, the inspector observed a small portion of the performance of STP-309-0602, "Division II 18-Month ECCS Test." The portion observed involved the simulated loss of offsite power to Division II systems, and the starting and loading of the Division II EDG, as required by TS 4.8.1.1.2.f.4.a.1 and -2.

The inspector noted that, although the test was very complicated and required certain rapid responses, the testing personnel maintained control of the test, provided adequate coverage, collected appropriate data, and followed the procedure. Plant equipment responded as designed.

Conclusions

In addition to the observations discussed above, the inspector reviewed selected portions of the surveillance program to verify that surveillances, as a whole, were being performed within the required frequency. The licensee's program appeared to be strong in implementation of individual procedures, as evidenced by the observations made during this inspection period.

7. Installation and Testing of Modifications (37828)

During this inspection period, several operational events occurred as a result of modification activities in the plant. The inspector reviewed the following three events for generic significance within the licensee's modification program.

a. RWCU Isolation

On November 4, 1990, the licensee experienced an isolation of the RWCU system while the system was in service cleaning the upper cavity. The isolation occurred when the power supply (E31-K6008) for several RWCU trip circuits was inadvertently deenergized, during installation of MR 87-0837, causing a high differential flow isolation signal to be generated, and closing Valves G33-MOV-F040 and G33-MOV-F028 (the RWCU return and reject isolation valves). All valves required to isolate did so with the exception of two valves which were tagged open for maintenance. The power was restored, the isolation signal was reset, and the RWCU system was returned to operation.

At the time of the event, work under the MR was in progress to replace a turbine flowmeter with a magnetic flowmeter (1E31-FTN021) on a floor drain unit cooler condensate leakoff line. The modification required the removal of Fuse F7B from the circuit. The engineering review failed to identify that several other fuses were connected to Fuse F7B in a daisy-chain manner. The removal of Fuse F7B also disconnected Fuse F24, which deenergized Power Supply E31-K6008. This arrangement was clearly identified on Electrical Drawing 0242.424-000-659G. However, elementary Drawing 851E602AA, Sheet 4, Revision 20, did not indicate how the fuses were terminated.

The licensee initiated CR 90-1070 to implement corrective action for this event.

b. Loss of Shutdown Cooling

On October 27, 1990, the licensee experienced a loss of shutdown cooling for approximately 2 minutes. The loss occurred when the RHR Pump B, supplying shutdown cooling at the time, tripped on low suction pressure as a result of the suction line isolation valve (E12-MOV*F009) failing closed. The operators took prompt corrective action to correct the problem, open the isolation valve, and restart the pump. No change in the reactor or upper cavity water temperature was detected during the event.

At the time of the event, electricians were installing a portion of MR 87-0576 to add additional indication to the main control panels for nuclear steam supply shutoff system actuations. The current indication only provides a status of the Group 1 isolation (main steam line isolation valve closure). However, all the isolations utilize the same isolation reset pushbutton. This modification moved the indication for each isolation to the front panel, giving the operators a complete status.

The work was being performed in accordance with MWO R 126467, as specified by MR 87-0576. The electricians were performing Step 35 that required the craftsman to make wiring additions in Bay A, at J0005, Location 9F01, as required by Attachment 151. The attachment discussed the addition of six pins and eight wire connections. The electricians disconnected Jack Plug 5 (J0005) on control room Panel H13*P692, as required by this procedure, when the isolation occurred.

During a review of the event, the licensee determined that Pin T of the plug disconnected power through the Optical Oscillator AT-39 and to the K-129 relay in Division 2 of the RPS, causing it to drop out. This was shown on GE Elementary Drawing 828E445AA, Sheet 15. As shown on Drawing 828E445AA, Sheet 11, deenergizing this relay closed the contacts at M1 and R1, causing the closure circuit for Valve E12-MOV*F009 to energize. The valve responded as designed and isolated the suction path of RHR Pump B.

The licensee initiated CR 90-1013 and the findings indicated that the system engineer had failed to detect all of the circuits affected by jack Plug 5. The engineer stated that he reviewed the drawings prior to initiating the work and merely missed the Pin T circuit. The drawings did appear to be difficult to read, in that, all the pins from J0005 were not indicated clearly. The shift supervisor stated that he had relied on the engineer's research and probably should have done a more thorough review. The inspectors reviewed the circuitry and the associated drawings and performed interviews with the engineer and the licensed operators involved.

c. RPS Half-Scram Inadvertently Initiated

On November 8, 1990, with the plant shut down in the refueling mode, the licensee experienced a Division I isolation and received an RPS half-scram signal. The signals occurred when work in the plant caused a momentary interruption of the RPS A normal electrical supply. The isolation caused a loss of suction flow to RHR Pump B pump. All isolations occurred as expected for the existing plant conditions and all systems were restored to their previous configuration with no abnormalities. No change in refueling pool water temperature or level was noted.

At the time of the event, electricians were installing modification MR 89-0056 to add indication of the RPS A alternate electrical supply to the main control panel. A recent field change notice had, in part, incorrectly changed the terminal to be disconnected during the modification. The engineer stated that he had incorrectly read Drawing 0247.350-000-075J by mistaking a line representing the cabinet side for a line representing one of the conductors. The loosening of this terminal caused the interruption in the normal electrical supply.

Also at the time of the event, the plant was lined up for shutdown cooling utilizing the RHR Train B (Division II) in the fuel pool cooling assist mode. This lineup included an RHR suction path through the SFC system. The Division I isolation caused Valve SFC*MOV121 to close, interrupting the suction path to the Division II RHR pump. The plant had alternate decay heat removal available through the RWCU system. The licensee documented the event in CR 90-1091.

d. Overview

The inspector reviewed Procedures ENG-3-6, "River Bend Station Design and Modification Request Control Plan," and EDP-AA-58, "Design Verification," to verify that the design process was appropriately implemented with respect to these three modifications. The inspector noted that design engineering personnel and management stated that, although they are responsible for the impact that a modification will have when installed in the plant, design engineering is not responsible for the impact of the modifications while being installed.

Design engineering personnel also stated that they were responsible for certain detailed work instructions, and that maintenance planning often used these instructions verbatim in the planning of the modification installation. The inspector questioned the adequacy of this practice when design engineering does not review modifications for installation impact.

The inspector will review the licensee's maintenance planning procedures, and evaluate the above discussed events as related to proper planning. This review will include the appropriateness of the planning practices, design engineering/maintenance planning interface, planning for plant impact, and review of the specific planning activities surrounding these three events. The inspector will also determine if regulatory requirements were violated during the planning and implementation of these three modifications.

The review of these three events and the modification process is considered an unresolved item (458/9029-03).

Conclusions

Due to the nature of the problem experienced during the installation of modifications, it appeared that the licensee had not specified, within their organizational structure, the department responsible for reviewing the effect on systems when the modifications are actually being installed.

8. Engineered Safety Feature System Walkdown (71710)

The inspector walked down accessible portions of the HPCS system. The inspector verified that SOP-0030 and P&ID 27-4A agreed with each other, and that the plant was aligned in standby in accordance with the SOP. The 480-volt motor control center (1E22*S002) was inspected for proper fusing, bolting, breaker alignment, and cleanliness. During the walkdown, the inspector found the following items and discussed them with the licensee:

- Valve E22*V53 (HPCS discharge line inside containment drain and LCM connection) was locked open and should have been locked closed per the SOP and P&ID. The licensee showed the inspector that the valve was inside a clearance boundary and would have been repositioned prior to startup.

- Valve E22*MOV-F015 (HPCS pump suppression pool suction valve) was found to be full open. Although the SOP lineup required this valve to be fully closed, the safety-related position for this valve was open. Additionally, the licensee stated that the valve had been accidentally realigned during the drywell bypass leakage test and would be realigned following the test. The inspector later verified that the valve had been realigned.

- Valve E22*V301 (minimum flow to suppression pool drain/LCM) had the handwheel removed. The licensee initiated MWO R 143216 to correct the problem.

- Valve E22*V24 (root valve to flow rate Transmitter 1E22-FEN007) was not sealed open as required by SOP-0030. The licensee verified that the valve was open and sealed the valve in this position. The inspector noted that the valve had tie wire around the bonnet, which appeared to have sealed the valve open before, and that its sister valve (E22*V22) on the other side of the flow element was sealed open. Additionally, it should be noted, that this valve is not required to be sealed open by the system design, only by the more conservative operating procedure.

- A hanger on a 4-inch line in the area of the HPCS piping had been disconnected and not replaced. No documentation or tags were present on the hanger. The licensee initiated MWO R 143215 to correct the problem. The inspector noted that this was not a safety-related line.

The above items did not effect the operability of the HPCS system and were considered minor in nature. General housekeeping in the areas inspected was good. The licensee has made significant efforts in upgrading the aesthetic condition of the HPCS system.

9. <u>Followup of Regional Requests (92701)</u>

a. <u>Fuel Problems</u>

On November 6 and 7, 1990, the licensee performed the normal core verification following refueling. During the inspection, the licensee identified several discrepancies in fuel orientation and positioning. The following items were found to be incorrect:

- Four assemblies were not in their correct orientation.

- Seven assemblies were not seated properly because of channel fastener interference.

- Four assemblies were not seated fully in the core.

- One assembly was neither seated nor oriented properly.

- One fuel support piece was not correctly seated.

The licensee performed inspections of the channel fasteners using an underwater camera. All assemblies mentioned above were reoriented and/or reseated.

The control cell, in which the fuel support piece was not seated, had been defueled and had a control blade guide installed. The licensee withdrew the blade and reseated the support piece as soon as the control rod drive hydraulic system had been returned to service.

During the refueling, core alterations included 1070 complete fuel movements, 66 fuel assemblies sipped for leakage, 24 control blade replacements, and 16 control rod drive replacements.

Following the discovery of the discrepancies, Region IV dispatched a specialist to review the licensee's loading problems and to investigate the details behind the two leaking fuel bundles discovered during plant operations in April 1990.

During an inspection conducted November 13-16, 1990, several of the licensee's activities associated with the occurrence of failed fuel were inspected. Specifically, the following areas were examined: chemistry sampling, local power changes in the proximity of the bundles that experienced failures, manufacturing controls associated with the failed fuel cladding lots, out-of-core and in-core fuel movements, postirradiation examinations, fuel failure analysis, and licensee plans in the event that additional failures occur in Cycle 4 operation. The results of this inspection are given below:

(1) <u>Fuel Failure Problems</u>

During Cycle 3 operation, the licensee incurred limited fuel rod failures. The first indication of fuel failure occurred on April 24, 1990. Later in the cycle, the licensee became aware of a potential second fuel failure. Following the identification of failed fuel in Cycle 3 operation, the license's fuel integrity committee met frequently in an effort to determine the location of the failed fuel, potential fuel failure mechanism, and operational changes that may have been warranted to preclude further failures.

Through the monitoring of offgas activity subsequent to control rod movement, the licensee was able to locate 8 bundles that were likely to contain the leaking fuel rods. During the third refueling outage, the licensee sipped 66 fuel bundles and identified 2 bundles having failed fuel rods. These bundles with failed fuel rods will not be used in Cycle 4 operation. The licensee speculated that the cause of the fuel failures may be the result of manufacturing defects in the fuel cladding. Consequently, a failed fuel action plan was developed to manage the effects of subsequent fuel failures during Cycle 4 operation.

(2) <u>Chemistry</u>

The licensee routinely sampled both reactor coolant and feedwater. Feedwater monitoring included: fluorides, sulfides, silicon, chlorides, sodium, iron (soluble and insoluble), cobalt, aluminum, chromium, nickel, copper (soluble and insoluble), phosphates, nitrates, and dissolved oxygen. While in Mode 1 operation feedwater sampling for the various substances ranged from twice-per-day to once-per-week.

The fuel warranty operationally limits copper in the feedwater to less than 0.5 ppb. However, there is no operational limitation imposed on copper in other sources of water to the reactor vessel or in the RCS. The licensee's analysis of feedwater sampling for Cycles 2 and 3 indicated that the licensee maintained feedwater copper substantially below the feedwater warranty limitation. The licensee's chemical analysis indicated that total copper in the reactor vessel averaged around 5 ppb and ranged up to 50 ppb during Cycle 2 and 3 operation.

During Cycle 2 and 3 operation, there were no licensee-identified instances of the RCS chemistry exceeding the TS limits. A licensee representative also stated that there had been no known instances when turbine electrohydraulic control fluid entered the condensate. There was one occasion where a few pounds of demineralizer resins passed into the feedwater. The licensee representative believed that this limited amount of resin should not have created a problem to the protective oxide on the fuel cladding.

(3) Power

The inspector reviewed the licensee's analyses of maximum critical power ratio, maximum average planar linear heat generation rate, and maximum power density calculated for Cycle 2 and 3 operation. The inspector found these analyses indicated that the fuel had been operated within the limits of the TS. It was noted that the first chemical and offgas indications of failed fuel occurred shortly after a power increase from 15 to 100 percent power. The inspector also noted that the fuel manufacturer did not impose any preconditioning limits nor any pellet cladding interim operating management recommendations for the barrier fuel cladding.

(4) Cladding Manufacturing

The licensee obtained answers from GE regarding the cladding manufacturing process and material specifications that indicated that the first reload fuel cladding was manufactured in conformance with GESAR provisions and NRC staff understanding. The inspector also examined the licensee's receipt inspection records for the two bundles containing failed fuel. No discrepancies were noted during this review.

(5) Failed Fuel Action Plan

The licensee has developed a failed fuel action plan to address licensee options in the event that additional fuel failures occur during Cycle 4 operation. The action plan described, in basic terms, the escalating actions that the licensee would take as offgas activity increases. The plan reflected the experience gained during Cycle 3 operation and appeared to be a prudent outline of major actions that might be needed if additional failures occur.

(6) Postirradiation Examination

Neither the licensee nor the fuel manufacturer has performed a PIE to establish the fuel failure mechanism(s). In the SER for the RBS, the NRC staff addressed fuel PIE. The applicant had not proposed a PIE in the FSAR but had committed to perform an acceptable PIE. The SER specified that the issue would be treated as a confirmatory issue. Subsequently, at the proposal of GE, documented in a November 23, 1983, letter from J. S. Charnley (GE) to C. H. Berlinger (NRC) on the postirradiation fuel surveillance program, the NRC staff accepted the position that an acceptable PIE for the RBS could be provided by GE. This acceptance was documented in a June 27, 1984, letter from L. S. Rubenstein (NRC) to R. L. Gridley (GE) on the acceptance of a GE-proposed fuel surveillance program. Subsequently, during the review of the GESAR, the NRC staff SER accepted that GE would provide routine PIE for their fuel. Moreover, the NRC SER stated that surveillance beyond the routine surveillance might be required in the event of a fuel problem.

GE recommended to the licensee that all first reload fuel bundles be sipped. Based on the confidence that the licensee had, on their preoutage prediction of which fuel bundles contained leakers and the likely size of cladding perforations, the outage PIE that was performed had been limited to the sipping of 66 bundles. The sipping revealed that two bundles contained failed fuel rods. The bundle identification numbers were LYN760 and LYH845. The two failed bundles were in their second cycle of operation and had accrued exposures of 23,056 MWD/MTU and 21,960 MWD/MTU, respectively, at the time of cladding breach.

The licensee has not dechanneled fuel bundles; therefore, individual spent fuel rods have not been visible for examination. The licensee expected, but has not decided whether further PIE will be performed. It is possible that a PIE effort may be performed in conjunction wit' a reconstitution of the bundles for future reuse.

(7) Fuel Failure Mechanism

There are several failure mechanisms that may be responsible for the Cycle 3 fuel rod failures. In particular, pellet-cladding mechanical interaction, crud-induced localized corrosion, cladding manufacturing defects, and cladding fretting. The two former mechanisms were basically dismissed as viable failure mechanisms in the NRC staff's FSAR and GESAR evaluations. PCMI is unlikely since the fuel is the new GE barrier fuel cladding, which is generally accepted as highly resistant to power ramp changes. This is evidenced by the fact that the GE barrier fuel warranty is no longer dependant upon power ramp limitations. The NRC staff's evaluation concluded that the CILC failure mechanism is unlikely because the RBS utilizes deep-bed demineralizers which minimize copper contamination in the feedwater. The failure mechanism of fretting is generally not prevalent in boiling water reactors. Current speculation by the licensee is that the responsible failure mechanism is incipient defects in the cladding wall that were undetected during the manufacturing process. This explanation has been offered by GE representatives who found that an ultrasonic testing device, used at the Wilmington, North Carolina plant during the time that the RBS first reload fuel was manufactured, was unable to identify small defects of a certain geometric shape.

(8) Fuel Bundle Seating and Orientation Problems

Following the fuel shuffle, two fuel positioning problems were identified by the licensee during the core loading verification process. The core loading verification process involved personnel from reactor engineering, core analysis, and quality assurance. During the verification process, a television camera was used to verify that fuel bundle serial numbers and orientations corresponded to the reload core map. Also, the core height was checked by viewing the elevation of fuel bundles. The core loading verification process used by the licensee was considered by the inspector to be a thorough means of finding core loading problems.

One problem that the licensee identified from the monitoring of the core height was that 12 fuel bundles were not fully seated, but were somewhat elevated. These bundles were reseated by performing minor adjustments with the main fuel mast. In addition, 4 other fuel bundles were found to be improperly seated because their fuel support piece was not seated properly. This particular fuel support piece was one that was removed during the outage to replace the control blade, which was expected to reach its design life exposure limits during Cycle 4 operation. The licensee speculated that, given the limited tolerance between the fuel support piece and its guide tube, boiler scale may have interfered with proper seating. Upon replacing the fuel support piece with one obtained from Grand Gulf Nuclear Station, the associated 4 bundles properly aligned with the core height.

The second problem that the licensee identified was that five fuel bundles were misoriented during the loading of the Cycle 4 core. Four of the bundles were misoriented by 180 degrees and one bundle was misoriented by 90 degrees. The misoriented bundle identification numbers were LYP408, LYV206, LYV281, LYV283, and LY9685. The misorientations occurred on November 5 and 6, 1990, and involved three separate licensee crews (one reactor engineer and one SRO per crew). The loading process also involved two other operational crew members (GE contractors) in containment.

All five misoriented bundles were determined to be located in their proper core lattice locations. One of these bundles was also one of the bundles that was improperly seated. Because the RBS core loading design is in an S lattice that provides equidistance between bundles on all four sides, peaking factors are relatively insensitive to misorientation. The thermal margin safety analysis for a single misoriented bundle would have remained valid even if the licensee had not detected and corrected the misorientations. The NRC staff evaluation did not, however, address the impact of misoriented fuel bundles being adjacent to one another. Also, had these misorientations not been detected, a potential adverse increase in control rod scram time may have occurred as a result of increased frictional interference from the channel spacing buttons being misoriented. In regard to the Cycle 4 core loading problems, the licensee identified that none of the five misoriented fuel bundles were adjacent to one another.

The procedure governing the fuel loading process is REP-0010, "Special Nuclear Material Movement Control and Accounting," Revision 7, dated July 20, 1990. The procedure did not define a fuel bundle misorientation as a fuel load error. It permitted SRO and reactor engineer discretion for such instances, if they are recognized. Specifically, Attachment 8 stated a misrotated bundle is not a fuel loading error. Corrections can be made at the discretion of the refuel SRO and on-duty reactor engineer as appropriate.

The inspector identified that the procedure did not require that, when such discretion was employed, the refueling crew document such misorientations to ensure that the proper orientations can be made at a later time. Consequently, there was an inherent, undue reliance on the core loading verification process to catch such misorientations. Moreover, the procedure required that both of the licensee personnel sign off on the validity of each fuel move and the proper placement of each fuel bundle. Hence, if discretion was employed it would conflict with the sign off affirmation that the particular bundle was loaded according to the plan.

For a bundle misorientation error to occur, it required all four personnel involved in the loading process to consecutively err. The licensee believed that the misorientations that occurred during this outage did not involve discretion but, rather, were inadvertent. The licensee believed that the determination of proper fuel bundle orientation was hampered during the fuel shuffling process by poor visibility due to distance (about a 60-foot depth), thermal currents, and coolant clarity. In fact, the refueling outage was delayed several days to allow reactor coolant water clarity to improve.

A licensee representative stated that a similar occurrence involving a misoriented fuel bundle occurred during the first refueling outage and was also identified by the core loading verification process. The previous occurrence was not regarded by the licensee as an error and, thus, was not documented on a CR, and no known corrective action was taken. During this refueling outage, the licensee decided to write a CR on the basis that several additional fuel movements were required to properly orient the five bundles. In regard to corrective action to prevent recurrence of this problem, the licensee was contemplating the placement of a camera on the fuel mast to better aid the refueling crew in placing fuel bundles.

TS 6.8.1.c requires that written procedures be established and implemented covering refueling operations. Contrary to this requirement, activities were not implemented in accordance with the procedure in that the five subject bundles were misoriented. This is a violation (458/9029-04).

b. Rosemount Transmitters

On November 14, 1990, the inspector reviewed CR 90-1103 that documented the receipt of a preliminary (i.e., unofficial) copy of a Rosemount memorandum dated October 31, 1990. This memorandum identified 11 additional Model 1153 and 1154 transmitters that are on the suspect lot list for potential loss of fill fluid. The CR stated that, of the transmitters listed, only 3 provide a safety actuation function and should be included under the requirements of NRC Bulletin 90-01, "Loss of Fill Oil in Transmitters Manufactured by Rosemount." It also stated that the other transmitters had either been previously evaluated or served only as an indication and/or annunciation function. The inspector noted that the CR contained documentation that supported this statement.

During a telephone conference on November 14, 1990, the inspector and members of the NRC staff discussed the matter with licensee representatives. It was asserted that the three transmitters in question (1B21*LTN073L, R, and G) had not exhibited any symptoms of oil loss. These components are three of the four transmitters that are required to provide a one-out-of-two, twice signal for HPCS actuation and HPCS EDG start on a Level 2 signal in the reactor vessel. A diversified backup initiation signal would also provide a

Division III (i.e. HPCS system and associated EDG) start on high drywell pressure.

The licensee replied to NRC Bulletin 90-01 on July 20, 1990, and pointed out that they were responding to a Rosemount document that had not been received through normal channels. The licensee initially considered replacement of the affected transmitters during the next refueling outage (RF-4), pointing out that operators perform a channel check twice daily in addition to other required surveillances, and that historical calibration data did not reflect drift characteristics of transmitters that have failed due to a loss of fill fluid (i.e., a cumulative loss in one direction only). They also stated that, on two earlier occasions, operators were able to detect and identify failing transmitters during the channel checks. Mr. P. Graham, Plant Manager, committed to having a midcycle outage and intends to replace the transmitters then or during any earlier outage of sufficient duration. This item will be reviewed further by the inspector and will be tracked as an inspector followup item (458/9029-05).

c. Feedwater Nozzle Indication

On November 13, 1990, the inspector discussed the results of ultrasonic testing on the N4A-2 feedwater nozzle to safe-end weld during this refueling outage. An indication was discovered in this weld during the second refueling outage. As a result, a midcycle inspection was performed. The result of the examinations showed an increase in flaw length of 1.1 inches, and an increase in flaw depth of 0.13 inches.

The circumferential indication was sized by manual examination during RF-2 to be approximately 6.125 inches long, with a maximum depth of approximately 0.2 inches and an average depth of 0.16 inches. The results of the midcycle outage revealed no increase in depth with an increase in length of 0.5 inches to a total length of 6.625 inches. The results of the RF-3 examinations showed a maximum length of 7.7 inches and a maximum depth of 0.33 inches. The pipe wall is 1.1 inch, giving approximately a 30 percent through-wall indication. It was also noted that the 7.7-inch circumferential indication is approximately 20 percent of the approximately 37.7-inch circumference.

The licensee stated that a conservative estimate of flow size after 7000 hours of operation would be below the ASME Code allowable values and thus concluded that operation to the midcycle outage, scheduled for September 1991, was acceptable in the current condition. The licensee will also take the following corrective actions:

- Reexamine the nozzle weld during the upcoming midcycle outage and provide the results to the NRC. Preparations for repair will be made should the indication be outside allowable bounds.

° Reexamine the nozzle weld during RF-4 per requirements of Generic Letter 88-01.

The above information is based on the inspector review of the November 19, 1990, letter to the NRC from GSU, discussions with the licensee on November 13, and a telephone conference with RBS and contractor personnel and the members of the NRC staff on November 16. On November 23 the NRC issued a letter to GSU stating that there was reasonable assurance that structural integrity of the nozzle to safe-end weld will be maintained and River Bend Station may continue operation to midcycle, which is scheduled for late September 1991.

This item will be reviewed further by the inspector and will be tracked as an inspector followup item (458/9029-06).

10. Followup of Previously Identified Items (92710)

(Closed) Inspector Followup Item 458/8802-01: Torque switch close problems in certain Limitorque operators

The operability and reportability of Valves 1E51*MOV-F063, 1E51*MOV-F076, 1FWS*MOV-007A, and 1FWS*MOV-007B, in their as-found condition, were indeterminate.

The licensee evaluated the operability and reportability of the valves and documented a response in EEAR 88-R0101. The inspector reviewed the EEAR response and the MWOs associated with the checks performed on the valves.

The inspector noted that although 27 percent of the valves checked had bolting with breaking torque values less than 70 percent, only one bolt of four or two bolts per eight maximum were loose, representing only 5 percent of the bolts checked. It is also noted that only three of these valves were SMB-4s and that no discernible trend was identified.

Additionally, the licensee stated that engineering review had shown that one of four or two of eight bolts being less than 70 percent of required torque is an acceptable condition, and all of the bolting breaking below the required torque, but at a value greater than 70 percent, is an acceptable condition. This licensee position is documented in LER 86-030. However, all bolts found to be less than the required torque values were retorqued to this value.

The licensee determined that the continuing problem with Valves 1FWS*MOV-007A and 1FWS*MOV-007B had been caused by the excessive force applied by the actuator causing local yielding of the bolts and/or threads. This, coupled with the inadequate thread engagement, led to the original failure. The bolting was replaced, the actuators repaired, and the OATIS machine was used to set the torque switch to achieve the required thrust. Questions concerning the OATIS signature testing and additional functional testing of all safety-related MOVs is being performed and reviewed under NRC Bulletin 89-10.

11. Midcycle Plant Performance Review (35502)

On November 19, 1990, a conference was held at the site between the licensee and Region IV personnel to discuss the NRC's evaluation of the licensee's performance at the approximate midpoint of the current SALP cycle. The licensee's current SALP cycle extends from January 1, 1990, to March 31, 1991.

The NRC conducts a performance review to provide feedback to the licensee on the current status of their performance. The attendees at the meeting are listed in paragraph 1.

12. Exit Interview

An exit interview was conducted with licensee representatives identified in paragraph 1 on November 27, 1990. During this interview, the inspectors reviewed the scope and findings of the inspection, as well as the findings discussed during the November 16, 1990, exit interview. The licensee committed to perform an examination of the feedwater nozzle to safe-end weld during a midcycle outage scheduled for September 1991. Additionally, the licensee committed to replace three Rosemount transmitters in the HPCS system during the midcycle outage or any prior outage of sufficient duration.

During the interview, the licensee identified three documents reviewed by the inspectors during this inspection period as containing proprietary information. The inspectors verified that NRC notes, draft documents, and this inspection report did not contain proprietary information, and that the documents in question had been returned to the licensee.

ATTACHMENT

LIST OF ACRONYMS AND INITIALISMS

ac - alternating current
ADS - automatic depressurization system
ASME - American Society of Mechanical Engineers
BOP - balance of plant
CEO - chief executive officer
CILC - crud-induced localized corrosion
CR - condition report
CST - condensate storage tank
ECCS - emergency core cooling system
EDG - emergency diesel generator
EDP - engineering department procedure
EEAR - engineering evaluation and assistance report
ESF - engineered safety feature
FSAR - final safety analysis report
FWS - feedwater system
GE - General Electric
GESAR - General Electric safety analysis report
GSU - Gulf States Utilities
HPCS - high pressure core spray
HVAC - heating, ventilation, and air conditioning
IRM - intermediate range monitor
ISEG - independent safety review group
kW - kilowatt
LCM - leakage control monitoring
LER - licensee event report
LPCS - low pressure core spray
LPRM - local power range monitoring
MG - motor generator
MOV - motor-operated valve
MR - modification request
mrem - millirem
MTU - metric tons uranium
MWD - megawatt days
MSL - main steam line
MWO - maintenance work order
NTU - nephelometric turbidity units
OATIS - operations analysis and testing interpretive system
PCMI - pellet-cladding mechanical interaction
P&ID - piping and instrumentation diagram
PIE - postirradiation examination
PIP - position indication probe (control rod drive)
ppb - parts per billion
psig - pounds per square inch, gauge
RBS - River Bend Station
RCS - reactor coolant system
REP - reactor engineering procedure
RF - refueling outage
RHR - residual heat removal
RP - radiation protection
RPS - reactor protection system

RWCU - reactor water cleanup system
RWP - radiation work permit
RWS - reactor water sampling
SALP - systematic assessment of licensee performance
SER - safety evaluation report
SFC - spent fuel cooling
SOP - system operating procedure
SP - suppression pool
SRM - source range monitor
SRO - senior reactor operator
STP - surveillance test procedure
TIP - traversing incore probe
TS - Technical Specification
Vac - voltage, alternating current
Vdc - voltage, direct current
VHRA - very high radiation area