UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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May 1, 2000

Southern Nuclear Operating Company, Inc.
ATTN: Mr H. L. Sumner, Jr.
Vice President
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: NRC INTEGRATED INSPECTION REPORT NO. 50-321/00-02, 50-366/00-02, AND 72-36/00-02

Dear Mr. Sumner:

On April 1, 2000, the NRC completed an inspection at the Hatch Nuclear Plant. The enclosed integrated inspection report presents the results of that inspection. During the eight-week period covered by this inspection, the conduct of activities at the Hatch Nuclear Plant was generally characterized by safety-conscious operation, adequate maintenance practices and appropriate engineering support to the plant.

Based upon the results of this inspection, the NRC has determined that three violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCVs), consistent with Section VII.B.1.a of the Enforcement Policy. These NCVs are described in the enclosed integrated report. If you contest the violation or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region II, and the Director, Office of Enforcement, USNRC, Washington D.C. 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room (PDR).

Sincerely,
/RA/
Stephen J. Cahill, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Docket Nos. 50-321, 50-366, 72-36
License Nos. DPR-57, NPF-7

Enclosure: Inspection Report Nos. 50-321/00-02, 50-366/00-02, 72-36/00-02

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-321, 50-366, 72-36
License Nos:	DPR-57, NPF-5
Report Nos:	50-321/00-02, 50-366/00-02, 72-36/00-02
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	E. I. Hatch Plant, Units 1 & 2
Location:	P. O. Box 2010 Baxley, Georgia 31515
Dates:	February 06 - April 1, 2000
Inspectors:	J. Munday, Senior Resident Inspector T. Fredette, Resident Inspector B. Crowley, Regional Inspector (Sections M1.2, M1.3)
Approved by:	S. J. Cahill, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

Hatch Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-321/00-02, 50-366/00-02, 72-36/00-02

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers an eight-week period of resident inspection; in addition, it includes inspections conducted by a region-based inspector in the area of in-service inspection (ISI).

Operations

- The licensee developed an outage shutdown risk assessment which accurately identified time of increased plant risk. However, one plant configuration example was identified that was not addressed in the matrix. Actions recommended in the assessment were taken to minimize or control the increased risk (Section O1.3).

- Operators correctly complied with Technical Specifications when the drywell sump monitoring system had been rendered inoperable. The licensee was aware of system reliability problems and had developed appropriate controller failure contingencies and appropriate actions to upgrade the system (Section O2.1).

- An inadequate test procedure led to an automatic reactor scram signal being generated during Reactor Protection system testing. This issue was identified as a minor violation (Section O2.3).

- Several clearance errors occurred during the Unit 2 outage. The majority were attributable to administrative errors. The licensee initiated a self-assessment to examine the clearance problems and curtailed some administrative practices in authorizing personnel to work under clearance authorization. A non-cited violation was identified for clearance verification errors on safety-related components (Section O3.1).

- The Reactor Core Isolation Cooling (RCIC) System procedure did not contain adequate instructions for restarting the RCIC system following a trip on high reactor water level. A non-cited violation was identified for the inadequate procedure (Section O8.1).

- The licensee did not document the complications encountered with the RCIC system during a January 26, 2000, event in the associated Licensee Event Report (LER). A non-cited violation was identified (Section O8.1).

Maintenance

- Inservice inspection activities were being performed in accordance with procedures, licensee commitments and regulatory requirements with effective direction and oversight of contract personnel (Section M1.2).

- A detailed Flow Accelerated Corrosion program was in place and was being implemented in accordance with procedural requirements by knowledgeable license personnel (Section M1.3).

- The licensee's actions in identifying and assessing the condition of a degraded drywell electrical penetration were thorough. The plan for refurbishment of the penetration and functional testing of affected components was complete (Section M2.2).

- Maintenance associated with the Unit 2 safety relief valves was completed satisfactorily. However, ambiguous quality control inspection plans and inspection point assignment sheets contributed to two minor violations involving required inspections. Additionally, another minor violation was identified for inspections that were performed by an unqualified inspector (Section M2.3).

Engineering

- The licensee was aggressively pursuing solutions to stator cooling system copper oxide issues through monitoring and system enhancements (Section E2.1).

Report Details

Summary of Plant Status

Unit 1 began this report period ascending to 100% Rated Thermal Power (RTP) following a reactor trip that occurred on January 26. The unit reached 100% RTP on February 7. On February 19, power was reduced to 17% RTP and the main generator removed from service to clean and replace filter elements in the Generator Stator Cooling system. The unit returned to 100% RTP on February 20, where it operated for the remainder of the report period.

Unit 2 operated at approximately 98% RTP (limited by main turbine output) until March 4, when the unit was shut down for a refueling outage where it remained through the end of the report period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted periodic reviews of ongoing plant operations. Control Room activities, including, operator response to annunciators, control of ongoing evolutions, and shift turnovers were generally well controlled. However, the inspectors identified one example where plant conditions were not accurately identified during the turnover process. An automatic initiation of the Main Control Room Environmental Control (MCREC) system had occurred on night shift, as expected, when the movement of Unit 2 reactor internals increased localized radiation levels. This information was not logged or adequately discussed during turnover with the oncoming shift, nor did the oncoming shift identify that the system was in service. As a result, when the oncoming shift later discovered the system in service, an NRC notification for the actuation of an engineered safety feature (ESF), specifically the MCREC system in the pressurization mode was made. The licensee later retracted the notification. Operations management was evaluating appropriate corrective actions to address the poor communication of an automatic start and continued operation of an ESF system and the failure of the oncoming shift to identify it during initial control room panel walkdown.

O1.2 Unit 2 Shutdown For Scheduled Refueling Outage Activities

a. Inspection Scope (71707) (60710)

The inspectors observed the shut down of Unit 2 from the main control room in preparation for a refueling outage. In addition, entry into shutdown cooling, reactor vessel disassembly and reassembly, and fuel movement activities were observed. The inspectors reviewed the use of overtime by licensee personnel.

b. Observations and Findings

During the shutdown on March 4, the inspectors observed that the operators were deliberate in their actions and clear in their communications. Access to the control room was controlled; appropriate procedures were followed; and the unit was shut down without complications. The inspectors observed that operators exercised appropriate precautions when removing or placing systems in service.

The inspectors observed portions of initial reactor pressure vessel (RPV) disassembly and fuel movement activities in the main control room and from the refueling bridge. No operator deficiencies or fuel movement errors were identified.

The inspectors verified that licensee management maintained control of overtime in accordance with plant procedures and Technical Specifications (TS).

c. Conclusions

The inspectors identified no discrepancies during the unit shutdown in preparation for a refueling outage nor with reactor disassembly or refueling activities. Overtime was being controlled in accordance with site procedures and TS.

O1.3 Unit 2 Refueling Outage Risk Assessment (60710) (71707)

The inspectors reviewed the licensee's refueling outage risk assessment and discussed plant configurations with licensee personnel to determine those periods of increased shutdown risk. The inspectors also verified that various actions to reduce or control shutdown risk were in place. The inspectors routinely verified that these actions were implemented. The inspectors identified one plant configuration that the licensee had not considered in the outage risk assessment. A load center supplying power to the Unit 1 Division II Residual Heat Removal (RHR) system injection valve was aligned to its alternate source, Bus 1F. This is normally supplied power from one of two offsite sources with the emergency power source being supplied by Emergency Diesel Generator (EDG) 1B. Bus 1F also provides power to Unit 1 Division I RHR pump 1C and Division II RHR pump 1D.

The licensee removed EDG 1B from service to perform testing while the load center was aligned to Bus 1F. With this configuration, the Unit 1 RHR pumps would have been unavailable had Unit 1 experienced a loss of offsite power. This configuration existed for approximately five hours. Although the licensee had not fully considered all risk aspects of this configuration prior to performing the electrical realignment, the configuration was acceptable per the TS requirements for the 1B EDG. The inspectors verified that the licensee had correctly complied with TS. Further review by the licensee and the NRC also concluded that the alignment resulted in minimal risk to the operating unit.

The inspectors concluded that the licensee developed an outage shutdown risk assessment which identified time of increased plant risk and actions were taken to minimize or control the increased risk. The inspectors identified one example where the effects to the operating unit resulting from maintenance on the shutdown unit had not

been completely reviewed, however, the increased risk was determined to be minimal.

O2 Operational Status of Facilities and Equipment

O2.1 Unit 2 Drywell Equipment and Floor Drain Sump Monitoring System

a. Inspection Scope (71707) (62707)

The inspectors reviewed operating procedures, the Unit 2 Updated Final Safety Analysis Report (UFSAR) and TS, piping and instrumentation diagrams (P&IDs), maintenance data, and conducted a walk down of control system portions of the Unit 2 drywell sump monitoring system to assess system health in response to recent system unreliability. The inspectors also reviewed contingency actions for a loss of the system.

b. Observations and Findings

The inspectors reviewed the previous two years of maintenance history data for the Unit 2 drywell equipment and floor drain sumps; the sump monitoring system; and respective pump control systems. The inspectors identified that there had been a total of 16 maintenance work orders initiated as a result of various failures of the sump monitoring system primary and backup digital controllers. Discussions with maintenance personnel and Radwaste Operators revealed that many of the failures were attributed to obsolete or degraded controller components. The availability of the controllers was challenged by a lack of spare parts. On February 11, 2000, the inspectors observed that the front panel door for one controller was left open as a means of keeping electronic components located inside the panel cool. This had been recommended by instrumentation and control (I&C) technicians to enhance reliability. The component failures had resulted in overall reduced reliability of the system. As a result, the licensee initiated modifications to upgrade the system. The inspectors observed that the backup controller had already been removed as part of this upgrade, which is expected to be completed following the current Unit 2 refueling outage.

The inspectors reviewed component maintenance histories to determine if TS requirements had been satisfied during periods when multiple components were inoperable. The inspectors observed that there were only two instances when both sump monitoring system controllers were unavailable: May, 1999, and November, 1999. A review of operator logs determined that the containment atmospheric monitoring system had been available during both instances. As a result, Unit 2 was placed in a 30-day TS required action statement. The inspectors verified that TS 3.4.5 for RCS Leak Detection Instrumentation was satisfied during these periods and that the system was restored within 30 days.

The inspectors reviewed required responses to controller failures, including the “Controller Trouble” Annunciator Response Procedures (ARPs), both in the radwaste control room and main control room. The main control room ARPs directed that the radwaste operator check power to the controllers by checking a series of six fuses. The inspectors found that only one fuse was labeled and identified this condition to the

licensee. The licensee issued Condition Report CO0001610 to properly label the fuses. Although not identified in the ARPs, the licensee had developed contingency plans to implement if the controllers had failed during the Y2K transition. Temporary modifications 2-99-22 and 2-99-23 detailed the installation of electrical jumpers to bypass the controllers and enable manual operation of the drywell, reactor building, and turbine building sump pumps. No controller failures occurred during the Y2K transition and the temporary modifications were revised to be used as contingencies for any subsequent controller failures. The inspectors noted that the temporary modifications required detailed placing of electrical jumpers to bypass the controllers and enable manual operation of the drywell sump pumps. The inspectors noted that the ARPs did not address installation of jumpers to bypass the controllers and questioned the licensee about control of the jumpers and who was allowed to install them. The licensee stated that only qualified licensed operators or I&C technicians would be allowed to install the jumpers because the radwaste operators were not trained to install them. Installation of the jumpers did not require any additional or special training beyond that provided as part of the normal licensed operator or I&C technician qualification program. Therefore, the inspectors concluded that the jumpers were adequately controlled by the temporary modifications.

c. Conclusions

The inspectors concluded that the licensee was aware of the unreliability of the Unit 2 radwaste controllers, had initiated appropriate actions to replace them, and had developed appropriate contingencies for controller failure. Operators correctly complied with Technical Specifications when the sump monitoring system was inoperable.

O2.2 Decay Heat Removal (DHR) System (71707)

The inspectors reviewed operating procedure 34SO-G71-001-1S, “Decay Heat Removal System,” Revision (Rev.) 7, system schematics, and the licensee’s outage risk assessment, and conducted a walk down of the DHR system, including the dedicated system backup diesel generator. Additionally, the inspectors observed dedicated system operators conducting hourly status checks of the system.

The inspectors concluded that the DHR system was properly aligned and operated as required to support the Unit 2 outage. Operators were knowledgeable of the system risk importance. Access to the system components was controlled.

O2.3 Inadequate Test Procedure Results In Reactor Scram Signal on Unit 2

a. Inspection Scope (71707) (92903)

The inspectors reviewed the circumstances surrounding the initiation of a reactor scram signal that was generated during the performance of a surveillance test. The inspectors reviewed the applicable procedure and discussed the issue with the personnel involved.

b. Observations and Findings

On March 23, during the performance of procedure 42SV-C71-001-2S, “Reactor Protection System Logic System Functional Test,” a full reactor scram signal was generated. The unit was already in the refueling mode with all control rods fully inserted into the core. Section 7.11 of the test directed the reactor mode switch to be placed in the shutdown position, inserting a reactor scram signal. The Scram Discharge Volume (SDV) bypass switch was then placed in bypass to clear the scram signal due to a high level in the SDV and to allow the SDV vent and drain valves to open. Step 7.11.5 stated, “If necessary, on Panel 2H11-P603, RESET the reactor scram caused by the Mode Switch being placed in SHUT DOWN, THEN PLACE the Discharge Volume High Water Level Bypass switch, 2C71-S4, in NORMAL.” The procedure did not first ensure that the SDV high water level condition had cleared prior to placing the bypass switch back in the NORMAL position. When the SDV switch was placed in the NORMAL position the SDV water level was sufficiently high to cause a scram signal. The licensee properly reported the event to the NRC per 10 CFR 50.72 and was preparing a Licensee Event Report (LER).

The inspectors concluded that the test procedure was inadequate in that it did not contain steps to ensure the SDV high water level condition had cleared prior to taking the bypass switch out of the bypass position. However, when this action was taken, the control rods were already fully inserted in the core so the action did not adversely challenge the safety system. Therefore, the inadequate procedure was of minimal safety significance. It was documented in the licensee’s corrective action program as CR CO0002732 and is identified as a minor violation.

c. Conclusions

The inspectors concluded that an inadequate test procedure led to an automatic reactor scram signal being generated during the performance of a Reactor Protection system Surveillance Test. The inadequate procedure was identified as a minor violation.

O3 Operations Procedures and Documentation

O3.1 Review of Outage-Related Clearances

a. Inspection Scope (71707)

The inspectors reviewed procedure 30AC-OPS-001-0S, “Control of Equipment Clearances and Tags,” Rev. 20, and walked down selected clearances in place to support outage-related work.

b. Observations and Findings

The inspectors reviewed documentation and tagging for several safety-related clearances, including electrical switchgear. No deficiencies were identified. However, the inspectors observed that the licensee was experiencing an increasing number of problems related to clearances. The inspectors reviewed more than a dozen examples

and determined that the majority of the clearance issues were attributable to non-significant administrative errors. However, three of the examples involved significant clearance errors on safety-related equipment:

- During local leak rate testing (LLRT) of Unit 2 torus vent isolation valve 2T48-F082, the valve control switch on control room panel 2H11-P654 was tagged "open" in accordance with clearance 2-00-207. However, the control switch was in the "closed" position and the valve indicated closed. This is contrary to Step 8.7.1.3 of clearance procedure 30AC-OPS-001-0S, which states, in part, "Perform the clearance by positioning components and securing DANGER tags to the components indicated." The control switch was not in the position specified by the clearance sheet.

- Ground straps installed on 600-volt switchgear 2R24-S048 under clearance 2-00-273 were found installed on the low-voltage (208v) side of the switchgear. Steps 12-14 of the clearance sheet specified installation of ground straps on the 600v side of the bus to facilitate preventive maintenance on the 600v side.

- A danger tag for clearance 2-00-171 was left attached to low pressure coolant injection (LPCI) manual isolation valve 2E11-F060B, even though the clearance had been previously restored. This was contrary to Step 8.13.7.2 of the clearance procedure which states, in part, that for clearance restoration "As the DANGER tags are removed, the person removing the DANGER tag will initial and date in the "TAG REMOVED AND POSITIONED BY" block on the clearance sheet." The tag was not removed as specified by the clearance sheet.

In each of the above examples, two individuals performed these steps to ensure that they were completed correctly. The first two examples used "Double Verification" while the last example used "Independent Verification." Step 8.4.5 of the clearance procedure provides guidance on verification and states that "Initial tag out of safety-related equipment may be double verified; however, safety-related equipment clearance restoration <u>must</u> be independently verified." Step 8.7.1.6 states, in part, that for clearance installation "The person performing the independent or double verification will initial and date in "POSITION AND TAG VERIFIED BY" block on the equipment clearance sheet." Step 8.13.7.3 states, in part, that for clearance restoration "The person performing the independent verification will initial and date in "TAG REMOVED AND POSITION VERIFIED BY" block on the equipment clearance sheet." In each of the above examples, the verification requirements of the clearance procedure were not followed. These errors are significant due to the potential for equipment damage and personnel hazards when the clearance process is not followed.

Unit 2 Technical Specifications Section 5.4.1.a requires, in part, that written procedures shall be established, implemented and maintained covering applicable procedures recommended in NRC Regulatory Guide 1.33, Revision 2, Appendix A, 1978. Regulatory Guide 1.33, Appendix A, Section 1.c includes Equipment Control (e.g. locking and tagging). Contrary to the above, personnel failed to implement the clearance procedure in each of the above examples for verification of clearance steps involving safety-related equipment. In accordance with Section VII.B.1.a of the NRC Enforcement Policy, this violation is identified as Non-Cited Violation (NCV) 50-366/00-02-01, Failure to Conduct

Verification of Installed and Restored Clearances on Safety-Related Equipment. This violation is in the licensee's corrective action program as CR CO0001885, CR CO0002307 and CR CO0002851.

For immediate corrective actions operations management initiated a departmental self-assessment to examine clearance related issues. Additionally, telephone authorizations for subclearances were suspended, and written documentation certifying individual clearance qualifications were required of contractors engaged in clearance activities.

c. Conclusions

Several clearance related issues were identified during the Unit 2 outage. Although the majority of the issues were attributable to administrative errors, a non-cited violation was identified for clearance verification errors on safety-related components. The licensee initiated a self-assessment to examine the clearance problems and curtailed some administrative practices in authorizing personnel to work under the clearance process.

O8 Miscellaneous Operations Issues (92700) (92901)

O8.1 (Closed) LER 50-321/00-02: Reduction in Reactor Feedwater Flow Results in Automatic Reactor Shutdown on Low Water Level. On January 26, Unit 1 automatically tripped when an unexpected closure of a feedwater heater inlet valve occurred and reduced the feedwater flow to the reactor. The High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems automatic initiated and injected to recover reactor water level. A secondary containment isolation and auto initiation of the Standby Gas Treatment system also occurred. The licensee manually isolated the main steam isolation valves when reactor water level increased. In addition, various containment isolations occurred as required during the event. An NRC Augmented Inspection Team (AIT) was dispatched to follow up on the event and the results of that inspection are documented in Inspection Team Report 50-321, 366/00-01.

During the event, some systems malfunctioned or responded in a way that was not completely understood at the time. These included the unexpected closure of the "B" 5th stage feedwater heater inlet valve; safety relief valve (SRV) position indication that did not operate as expected due to water intrusion in the main steam lines and SRV bodies; and two damaged RCIC system steam line pressure transmitters and two additional steam line transmitters that could not be adjusted into calibration. The inspectors verified that these issues were sufficiently evaluated in the AIT report and no new information was provided in the licensee LER.

Two other issues included the HPCI system failure to immediately trip on a high reactor water level condition and several unsuccessful attempts, early in the recovery, to restart the RCIC system after it tripped on high reactor water level. Regarding HPCI, the licensee LER concluded that two failure modes were more likely than others: foreign material on relay contacts and a sticking turbine trip solenoid valve. Corrective actions included replacing the suspect relays and temporarily increasing the testing frequency of the HPCI turbine trip solenoid valve to once per week from the normal frequency of once per quarter.

Regarding the RCIC restart attempts, the AIT report identified that attempts to restart the RCIC system after it tripped on high reactor water level were unsuccessful due to the manner the system was being operated. The licensee's Event Review Team identified that the RCIC system operating procedure allowed the operator to attempt to restart the RCIC turbine by opening the Trip and Throttle (T&T) valve with the steam supply valve full open and the turbine control system demanding maximum speed. This method of restarting the tripped RCIC turbine contributed to repetitive overspeed trips during the event. The licensee revised the Operating Procedure to correct this problem.

10 CFR 50, Appendix B, Criterion V requires, in part, that activities affecting quality shall be prescribed by documented instructions or procedures of a type appropriate to the circumstances and shall be accomplished in accordance with those procedures. Contrary to the above, 34SO-E51-001-1S, Reactor Core Isolation Cooling (RCIC) System, Rev. 22 Ed. 1, did not contain adequate instructions for restarting the RCIC system following a trip on high reactor water level. Consistent with Section VII.B.1.a of the NRC Enforcement Policy, this Severity Level IV violation is identified as NCV 50-321, 366/00-02-02, Inadequate Procedure for Restarting RCIC Following a High Reactor Water Level Trip. This violation was identified in the licensee's corrective action program as CR CO000596.

In addition, the licensee LER did not identify or document these significant complications encountered with the RCIC system during the event. 10 CFR 50.73.b requires, in part, that the LER shall contain major occurrences during the event, including all component or system failures that contributed to the event and significant corrective action taken to prevent recurrence. In addition, it requires that operator actions that affected the course of the event, including procedural deficiencies be documented. Contrary to the above, the failure of the operators to successfully restart RCIC, as described above, was not documented in the LER. Consistent with Section VII.B.1.a of the NRC Enforcement Policy, this Severity Level IV violation is identified as NCV 50-321/00-02-03, Failure To Document Issues Required by 10 CFR 50.73. The licensee identified this issue in their corrective action program as CR CO0003312.

O8.2 <u>(Closed) LER 50-321/00-03: Failed Relay Coil Results in Unexpected Actuations of Engineered Safety Features</u>. This event occurred on January 29, when a relay coil failed, resulting in a blown fuse and actuation of several primary containment group isolations. The appropriate isolation valves closed as expected.

The failed relay was the subject of a vendor Service Information Letter (SIL) in April 1994. The SIL stated that relays used in a circuit that was continuously energized at a voltage higher than the relay rating had experienced failures. The SIL recommended monitoring the relay temperature and provided the relationship of the relays life expectancy with coil temperature. The licensee implemented the monitoring program. Based on the most recent coil temperature data collected, the life expectancy of the failed relay was indefinite, so the licensee was unable to determine what initiated the coil failure.

The licensee replaced the failed relay and fuse and realigned the components affected by the group isolations. In addition, a review of the event will be performed by the licensee's corporate engineering department to determine if actions in addition to those

identified in the SIL would be appropriate. No violations of regulatory requirements were noted. This LER is closed.

O8.3 (Closed) LER 50-321/00-01: Improperly Sized Differential Pressure Instruments Lead to Missed Technical Specifications Action Statements. This issue was previously identified as NCV 50-321,369/99-11-01, for inadequate design control, which resulted in installation of incorrect suppression pool level transmitters. The inspectors verified implementation of the licensee's corrective actions, which included replacement of the transmitters, appropriate broadness review, instrumentation and control (I&C) procedure revisions and training on the issue, and stress and hydrodynamic loading analysis of the Unit 1 and 2 suppression pool and torus structures due to increased suppression pool water level. No further problems were noted. This LER is closed.

O8.4 (Closed) LER 50-366/00-01: High Pressure Coolant Injection System Inoperable Due to Water in Lubricating Oil System. On February 27, the High Pressure Coolant Injection System (HPCI) was declared inoperable when water was discovered in the lubricating oil for the system. During the performance of the normal surveillance, personnel had observed water spraying from the area of the main pump outboard mechanical seal. The mechanical seal cavity was full of water and water was in the lubricating oil. The licensee determined that the outboard mechanical seal had a small leak which was collected in the seal cavity. This is normally drained to a sump, but the seal cavity drain line was clogged, which resulted in water in the seal cavity rising until it contacted the rotating shaft. The licensee concluded that water entered the lubricating oil system through the thrust bearing oil deflector which forms one of the walls for the mechanical seals. Although the oil deflector is designed to prevent oil from leaking out of the bearing housing, it is not designed to prevent leakage in the opposite direction. The licensee cleared the clogged drain line and intends to add a requirement to clean the lines during the 18-month preventive maintenance. The lubricating oil system was drained and cleaned. Subsequent oil samples were taken and identified less than 0.1 percent water, which was considered acceptable. No violations of regulatory requirements were noted. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (62707)

The inspectors reviewed several maintenance activities involving both safety-related and balance of plant equipment. The inspectors verified the appropriate procedures and maintenance work order (MWO) instructions were being used. In addition, several maintenance related surveillances were observed. One maintenance activity on Unit 2 resulted in an automatic start of the standby gas treatment system (SBGT) and secondary containment isolation when a wire became detached from its connection, touched an adjacent connection, and caused a small electrical arc to occur. The inspectors reviewed the work package and the work location with the involved personnel, and discussed the event with the licensee. The inspectors determined the activity was planned with appropriate precautions and the detached wire was inadvertent. No concerns were identified. The licensee reported the event to the NRC per 10 CFR 50.72 and was preparing a Licensee Event Report.

The inspectors concluded that the work packages were adequate for the intended jobs. Instructions and procedures were being adhered to. Maintenance observations are discussed in the paragraphs below.

M1.2 Unit 2 Inservice Inspection (73753)

The inspectors evaluated implementation of the licensee's inservice inspection (ISI) program by observing in-process work activities and review of selected procedures and records. The observations, procedures and records were compared to the TS and the applicable Code requirements (ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, with no Addenda).

Portions of the in-process ISI nondestructive examinations (NDE), including in-process records, were observed. Specific examinations observed included: liquid penetrant (PT) examination of three pipe welds; magnetic particle (MT) examination of one weld pipe support ; ultrasonic (UT) examinations of eight pipe welds; and review of completed videos for Visual (VT) examinations of five in-vessel components.

During the observations, the inspectors found that: detailed instructions and procedures were in place and were being followed by knowledgeable and qualified inspection personnel; approved and calibrated inspection equipment was being used; inspections were being performed in accordance with applicable Code requirements; and examination results were being properly evaluated and corrective actions taken as required. Qualified and knowledgeable personnel provided effective direction and oversight of contract personnel performing ISI examinations.

The inspectors concluded that ISI activities were being performed in accordance with procedures, licensee commitments and regulatory requirements with effective direction and oversight of contract personnel.

M1.3 Flow Accelerated Corrosion (FAC)(Unit 2) (49001)

The inspectors reviewed the FAC program procedures and observed portions of UT thickness measurements and/or grid layout for five selected components. Compliance with program procedure requirements, including evaluation and disposition of inspection results, was verified. The inspectors concluded that a detailed FAC program was in place and was being implementing in accordance with procedural requirements by knowledgeable and qualified personnel.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 2 Main Steam Isolation Valve (MSIV) Bushing Failures (62707)

During routine surveillance testing of MSIVs in January, 2000, the 2B inboard MSIV, 2B21-F022B, had failed to fully open with the control switch and had stuck in an intermediate position. Operators isolated the 2B steam line to conduct troubleshooting and further testing of the MSIV and position indication. The valve was opened after pneumatic pressure was increased, and operators successfully stroked the valve closed several times using the control switch. The closing stroke times met the TS acceptance criteria. The valve was determined to be operable because its isolation function was not impacted and a detailed inspection of this MSIV was planned for the March 2000, Unit 2 refueling outage.

During the refueling outage, the licensee determined that the stuffing box bushing had bound to the stem. The bushing was made of brass and is part of the normal packing arrangement for the valve. The licensee performed an inspection of the remaining inboard MSIVs and observed that the bushings in all the valves had bound to the stem to some degree. The licensee had to machine the bushings to remove them from the bonnets.

The licensee verified that the bushing material was adequate for this application. The bushings had been fabricated from stock brass by the licensee and according to the MWOs, to the recommended dimensions. At the close of this report period, the licensee was still evaluating for a root cause. The MSIV vendor indicated that the brass bushings were acceptable, but recommended a bushing made of carbon steel and cadmium. The licensee chose to use the vendor recommended bushings.

The brass bushings were not used on the Unit 2 outboard MSIVs and Unit 1 outboard MSIVs; however, they are currently installed in the Unit 1 inboard MSIVs. Periodic testing of those MSIVs has not indicated any problem with those valves. Licensee personnel stated that they would continue to monitor the performance of those MSIVs through routine surveillance testing.

The inspectors reviewed documentation to verify that the brass bushing material was acceptable for use in the MSIVs and was installed according to the packing program. Additionally, the inspectors verified that the isolation safety function of the MSIVs was not impacted by the use of the brass bushings.

M2.2 Post-maintenance Testing of Unit 2 Drywell Electrical Penetration (62707)

The inspectors reviewed elementary electrical diagrams, test procedures and work instructions, and verified that post-maintenance functional testing was adequate for drywell electrical penetration 2T52-X102A. The penetration was refurbished following an inspection that identified significant corrosion and general degradation of the electrical penetration terminal blocks.

The corrosion had originally been identified during troubleshooting of electrical circuits in

this same penetration in January, 1999; samples of the corrosion products were sent to a test lab for analysis and determination of the root cause. The root cause of the corrosion, documented in Significant Occurrence Report (SOR) CO9900493, was attributed to an atmosphere containing moisture and chlorides. The licensee postulated that the moist atmosphere was from a drywell cooling unit in the vicinity of the penetration.

The inspectors reviewed an Architect/Engineer (A/E) evaluation of the equipment electrical circuits affected by the penetration. The licensee determined that nearly 300 individual connections were affected, impacting numerous safety-related drywell components. The inspectors observed that a comprehensive functional test procedure was developed to address each affected electrical circuit.

The penetration refurbishment involved disconnecting each electrical conductor at the penetration and installing an environmentally qualified (EQ) jumper/connector to bypass the electrical terminal blocks. The inspectors observed that electrical continuity checks of selected jumper connections were satisfactory. The inspectors observed portions of the functional testing for selected circuits, including: reactor recirculation pump discharge valve stroking, motor rotation, indications and annunciators; safety relief valve continuity; and core spray header manual valve indication. The inspectors also verified from elementary drawings that the functional tests for this equipment were complete. No discrepancies were identified.

The inspectors concluded that the licensee's actions in identifying and assessing the condition of the drywell electrical penetration were thorough. The plan for refurbishment of the penetration and functional testing of affected components was complete. Functional testing was accomplished expeditiously.

M2.3 Unit 2 Safety Relief Valve (SRV) Maintenance (62707)

a. Inspection Scope

The inspectors reviewed documentation to verify the Unit 2 SRVs had been properly tested by the testing laboratory, met the acceptance criteria required by TS, and had been properly returned to service. In addition, the inspectors observed the SRVs after maintenance was complete to verify the insulation had been properly restored and the electrical cables had been appropriately routed.

b. Observations and Findings

The inspectors reviewed MWOs, associated procedures, SRV certification test reports, Quality Control (QC) inspection plans and reports, and QC inspector qualification records for maintenance of the eleven main steam SRVs. The certification test reports indicated that the pilot assemblies were properly set to lift at the setpoints required by TS. The inspectors verified the appropriate procedures were used to complete the activities. Authorizations were obtained and inspections performed as required by the procedure. The procedure clearly identified various hold points which required QC inspections; however, additional hold points required by the QC inspection plans and inspection point

assignment sheets were not as clearly identified making it difficult for workers to determine what components were required to be inspected and at what point in the maintenance. As a result, two errors occurred involving QC inspections. A hold point, identified in MWO 2990873, which required an inspection of the 2B21-F013M main valve body, was not performed. CR CO0002515 was issued to address this issue. The licensee and the inspectors verified that the inspection was not required by the ASME code, but rather was an inspection required by the planner as a good practice. In addition, Repair/Replacement plans and examination plans were not completed for four SRVs, 2B21-F013D, H, L, and M, prior to replacing bolting on the inlet and outlet flanges of the main valve body. However, a review of the MWOs for the four valves, 2990866, 2990870, 2990872, and 2990873, identified that the appropriate inspections had actually been performed. CR CO0003025 was written to document this issue. The inspectors verified that there was no additional inspection which would have been required of the new bolting.

The inspectors concluded that these two examples of failure to follow procedures were of little individual safety significance. However, they indicated that the process for identifying and scheduling QC inspections contained deficiencies and were identified as minor violations.

The inspectors reviewed QC inspector records to verify their qualifications were current for the type of inspections they had performed. No discrepancies were identified. The licensee had identified one individual who did not meet all the requirements of the licensee's program to perform QC inspections. CR CO0002986 was written to address this issue. The inspectors verified that the qualifications the inspector lacked were only required by the licensee's procedures and not the ASME code. The QC inspector had been qualified and conducted inspections at the site in the past, but his certification had expired in June, 1999. However, the licensee was able to successfully re-inspect the safety-related items inspected by the individual. In addition, several non-safety-related inspections were also able to be re-performed. No discrepancies were identified.

The inspectors concluded that this was another example where the licensee failed to follow the appropriate site QC procedures, that had little safety significance and identified this issue as a minor violation.

The inspectors verified that the insulation placed around the SRVs was installed according to the applicable procedure. No discrepancies were identified.

c. Conclusions

The inspectors concluded that the Unit 2 SRV maintenance and inspections were completed satisfactorily. However, ambiguous QC inspection plans and inspection point assignment sheets contributed to two minor violations involving required inspections. Another minor violation was identified involving inspections done by an unqualified inspector.

III. Engineering

E2 Engineering Support of Facilties and Equipment

E2.1 Stator Cooling System Reliability Issues (62707)(37551)

The inspectors reviewed the clogging of component filters and strainers in the Unit 1 generator stator cooling water system with licensee engineering personnel. The system has been in NRC Maintenance Rule (a)(1) status since an unisolable Y-strainer in the system had become clogged with a copper oxide in September, 1998, forcing a unit power reduction and generator outage to replace the strainer. In January, 2000, during a forced outage, the Y-strainer was checked again and a buildup of copper oxide film was found. In February, 2000, clogging occurred on another unisolable component, the rectifier filter assembly, forcing the licensee to take the generator out of service. The inspectors observed maintenance associated with that activity. Maintenance workers found residue in the 6 rectifier inlet filter cartridges and the 35 stator cooling inlet filter cartridges similar to the copper oxide in the above examples. Testing of the residue confirmed the presence of copper oxide.

The inspectors confirmed that maintenance and system engineering personnel were working with vendors, industry groups and other facilities to identify the cause and a viable solution. The licensee speculated that the copper oxide buildup was related to variances in system chemistry, flow and temperature, and noted it had only occurred on Unit 1. As a short-term solution, dual Y-strainers were installed on the Unit 2 Stator Cooling Water system during the current refueling outage and modifications were underway to install a dual rectifier filter assembly, allowing them to be changed on-line. Similar Unit 1 modifications were planned for the Fall 2000 refueling outage.

The inspectors verified that recent licensee maintenance rule status reports for the Stator Cooling Water system had (a)(1) goals for system chemistry that were being pursued and that trending of system performance was accomplished. A system evaluation was due in September, 2000. The inspectors concluded that the licensee was aggressively pursuing a long-term solution to stator cooling system copper oxide issues through monitoring and system enhancements.

V. Management Meetings and Other Areas

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on April 4, 2000. An interim exit meeting was held on March 17, 2000, to discuss the findings of Region based inspections. The licensee acknowledged the findings presented, but expressed dissenting comments regarding NCV 50-321/00-02-03. The licensee disagreed that this issue was a violation of 10 CFR 50.73.

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

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Betsill, J., Assistant General Manager - Operations
Curtis, S., Unit Superintendent
Davis, D., Plant Administration Manager
Dedrickson, R., Unit Superintendent
Fraser, O., Safety Audit and Engineering Review Supervisor
Googe, M., Performance Team Manager
Hammonds, J., Engineering Support Manager
Kirkley, W., Health Physics and Chemistry Manager
Lewis, J., Training and Emergency Preparedness Manager
Madison, D., Operations Manager
Moore, C., Assistant General Manager - Plant Support
Roberts, P., Outage and Planning Manager
Thompson, J., Nuclear Security Manager
Tipps, S., Nuclear Safety and Compliance Manager
Varnadore, R., Operations Support Superintendent
Wells, P., General Manager - Nuclear Plant

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 49001:	Inspection of Erosion/Corrosion Programs
IP 60710:	Refueling Activities
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 73753:	Inservice Inspection
IP 92700:	Onsite Followup of Written Reports of Non-routine Events at Power Reactor Facilities
IP 92901:	Followup - Plant Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

50-366/00-02-01	NCV	Failure to Conduct Verification of Installed and Restored Clearances on Safety-Related Equipment (Section O3.1)

50-321, 366/00-02-02	NCV	Inadequate Procedure for Restarting RCIC Following a High Reactor Water Level Trip (Section O8.1)
50-321/00-02-03	NCV	Failure To Document Issues Required by 10 CFR 50.73 (Section O8.1)
50-321/00-02	LER	Reduction in Reactor Feedwater Flow Results in Automatic Reactor Shutdown on Low Water Level (Section O8.1)
50-321/00-03	LER	Failed Relay Coil Results in Unexpected Actuations of Engineered Safety Features (Section O8.2)
50-321/00-01	LER	Improperly Sized Differential Pressure Instruments Lead to Missed Technical Specifications Action Statements (Section O8.3)
50-366/00-01	LER	High Pressure Coolant Injection System Inoperable Due to Water in Lubricating Oil System (Section O8.4)