UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

July 23, 2004

EA-04-037

Duke Energy Corporation (DEC)
ATTN.: Mr. R. A. Jones
Site Vice President
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION - FINAL SIGNIFICANCE DETERMINATION - INTEGRATED INSPECTION REPORT 05000269/2004003, 05000270/2004003, AND 05000287/2004003

Dear Mr. Jones:

On June 26, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Oconee Nuclear Station. The enclosed report documents the inspection findings which were discussed on **July 1**, 2004, with Mr. Dave Baxter and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC-identified finding of very low safety significance (Green). It also documents one self-revealing finding concerning the possible failure of the standby shutdown facility (SSF) auxiliary service water (ASW) pump to meet its 72-hour mission time, due to considerable accumulation of water in its inboard bearing lube oil that stemmed from a failure to correct excessive pump seal water leakage. In an NRC letter dated February 24, 2004, you were initially informed that the preliminary determination of this self-revealing finding was greater than Green. The letter stated that, "the finding was assessed based on the best available information, including influential assumptions, using the applicable Significance Determination Process (SDP)....Additional information from DEC would allow a more refined risk analysis. Such information could include: (1) Operational experience or testing data that provides insights on the ability of the SSF ASW pump to operate in the as-found condition; and (2) a more detailed understanding of water entry into the pump bearing and the effects on water/oil concentration during a 72 hour operating period." Accordingly, you conducted bearing testing commensurate with the as-found oil conditions and bearing loading, and formally communicated the results to the NRC in a letter dated June 10, 2004. Based on a review of this letter and the actual bearing test results, the staff agreed with your conclusion that the water contamination of the bearing lube oil would not likely have adversely affected the function of the SSF ASW pump during its mission time. Consequently, this self-revealing finding has since been determined to be Green.

In addition, the aforementioned findings were also determined to be violations of NRC requirements. However, because of their very low safety significance and because the issues were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Oconee facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,
/RA/

Robert Haag, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-269, 50-270, 50-287
License Nos.: DPR-38, DPR-47, DPR-55

Enclosure: NRC Integrated Inspection Report 05000269/2004003, 05000270/2004003, and 05000287/2004003 w/Attachment (Supplemental Information)

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-269, 50-270, 50-287
License Nos:	DPR-38, DPR-47, DPR-55
Report No:	50-269/2004003, 50-270/2004003, 50-287/2004003
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	March 28, 2004 - June 26, 2004
Inspectors:	M. Shannon, Senior Resident Inspector A. Hutto, Resident Inspector E. Riggs, Resident Inspector S. Walker, Resident Inspector - McGuire (Section 1R06) B. Crowley, Senior Reactor Inspector (Section 4OA5.6) J. Lenahan, Senior Reactor Inspector (Sections 1R08.1 and 4OA5.6) W. Bearden, Senior Resident Inspector - Browns Ferry, Unit 1 (Section 1R08.2) S. Vias, Senior Reactor Inspector (Sections 4OA5.7 and 4OA5.8) R. Aiello, Senior Operations Engineer (Section 4OA2.3)
Approved by:	R. Haag, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000269/2004003, IR 05000270/2004003, IR 05000287/2004003; 03/28/2004 - 06/26/2004; Oconee Nuclear Station, Units 1, 2, and 3; Identification and Resolution of Problems and Other Activities.

The report covered a three-month period of inspection by the onsite resident inspectors and announced regional-based inspections by: two visiting resident inspectors, three reactor inspectors, and one operations engineer. Two Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A NRC-identified, non-cited violation of 10 CFR 50 Appendix B, Criterion X, Inspection, was identified for inadequate quality control (QC) inspections of the Oconee Units 1, 2, and 3 Reactor Building Emergency Sumps (RBESs), in that, gaps, which may have existed since licensing of each plant, were not discovered during previous QC inspections.

  The finding was considered to be more than minor because it affected the mitigating systems cornerstone attribute of equipment performance reliability, in that, the inadequate QC inspections failed to identify RBES bypass flowpaths for debris to affect downstream emergency core cooling system components during RBES recirculation. However, because the gaps were small, the increase in the probability of debris bypassing the RBES screens was considered to be low. Consequently, the finding screened out of the Phase 1 SDP analysis as Green (very low safety significance). (Section 4OA2.2b(2))

- Green. A self-revealing, non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, was identified for the failure to correct identified packing leakage on the Standby Shutdown Facility (SSF) Auxiliary Service Water (ASW) pump, which resulted in the contamination of the pump’s inboard bearing lubricating oil with water.

  The finding was considered to be more than minor because it affected the mitigating systems cornerstone attribute of equipment performance reliability, in that, the failure to correct the pump’s packing leakage and resultant water contamination of the inboard bearing lubricating oil increased the likelihood of the SSF ASW pump failing to complete its mission time. As such, this finding was preliminarily identified as being “Greater Than Green” in NRC Choice Letter dated February 24, 2004 (i.e., Inspection Report 05000269,270,287/2004009). Subsequently, the licensee performed additional bearing testing commensurate with the as found contaminated oil conditions and bearing loading. The test results indicated that the water contamination of the inboard bearing lubricating oil would not likely have adversely affected the function of the SSF ASW pump during its mission time. The issue was subsequently reevaluated under the guidance of the reactor oversight process on June 30, 2004, and determined to be of very low safety significance (Green). (Section 4OA5.12)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status:

Unit 1 entered the report period at 100 percent rated thermal power (RTP) and remained there except for a reduction to approximately 88 percent RTP for turbine valve testing on June 19, 2004.

Unit 2 entered the report period during a refueling outage (RFO). The unit was brought on line on June 15, 2004, and achieved 100 percent RTP on June 17, 2004. Unit 2 remained at 100 percent RTP until June 25, 2004, when power was reduced to 15 percent and then taken off line for turbine oil system repairs.

Unit 3 entered the report period at 100 percent RTP and remained there except for when the unit was taken off line April 24, 2004, to balance the main turbine. Unit 3 was subsequently returned to 100 percent RTP on April 25, 2004.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

Severe Thunderstorm Conditions

a. Inspection Scope

The inspectors assessed whether the licensee responded appropriately to a severe thunderstorm warning on June 14, 2004. This included a verification that: (1) the licensee entered abnormal procedure (AP) O/A/1700/006, Natural Disaster, Tornado/High Wind Watch; (2) there were no ongoing maintenance activities on systems that required restoration by the procedure; and (3) control room personnel had completed steps 4.27-4.37, as required by the AP.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted partial equipment alignment walkdowns to evaluate the operability of selected redundant trains or backup systems while the other train or system was inoperable or out of service. The walkdowns included, as appropriate, reviews of plant procedures and other documents to determine correct system lineups, and verification of critical components to identify any discrepancies which could affect operability of the redundant train or backup system. The following systems were included in this review:

- Unit 1 and 3 Turbine Driven Emergency Feedwater (TDEFW) train with the SSF ASW system out of service (OOS) for scheduled maintenance

- Unit 3 A Train Motor Driven Emergency Feedwater (MDEFW) and TDEFW during B Train MDEFW performance testing

- Unit 3 B Train Low Pressure Injection (LPI) and Reactor Building Spray (RBS) during maintenance on Valves 3 LP-21 and 3 LPSW-251.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed review of the alignment and condition of the Keowee Hydro Units (KHUs). The inspectors utilized the licensee's system operating procedures and system drawings to verify proper system alignment. The walkdown also included an evaluation of the following system attributes:

- Circuit Breaker Air Reservoir Pressures
- Governor Oil Pressure Tanks Oil Level and Pressure
- Bearing Oil System
- Sump Pump Operation
- 125 Vdc System
- Housekeeping/Material Condition

A review of Problem Investigation Process reports (PIPs) and open maintenance work orders was performed to verify that material condition deficiencies did not significantly affect the ability of the KHUs to perform their design functions and that appropriate corrective action was being taken by the licensee. The following PIPs were reviewed: O-03-4119, O-03-4685, O-03-5006, O-03-5236, O-03-5454, O-03-8038, O-04-1910, and O-04-2824. The inspectors also met with the Keowee operations supervisor to discuss overall system health, any operational concerns or challenges, and implementation of the upcoming governor/voltage regulator replacement modifications.

Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours in seven areas of the plant to verify that combustibles and ignition sources were properly controlled, and that fire detection and suppression capabilities were intact. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis and the probabilistic risk assessment based sensitivity studies for fire-related core damage sequences. Inspections of the following areas were conducted during this inspection period:

- Keowee Hydro Units
- Unit 1 East Penetration Room
- Standby Shutdown Facility (SSF)
- High Pressure Service Water (HPSW) in Turbine Building with HPSW jockey pump out of service
- HPSW A and B pump Block Houses (compensatory measures for degraded fire barriers)
- Units 1 and 2 Spent Fuel Room
- Unit 3 Spent Fuel Room

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

Internal Flooding

The inspectors walked down procedure AP/3/A/1700/030, Auxiliary Building Flood, with two different Non-Licensed Operators, to verify the tasks necessary to be performed outside the control room in the event of a Unit 3 Auxiliary Building flood could be accomplished. The inspectors reviewed the procedure to verify it was appropriate, in that it: (1) identified proper sources of flooding; (2) was consistent with design analysis and assumptions; and (3) did not preclude required operator actions. Discussions were conducted with operations personnel and the design basis engineer in response to inquiries the inspector had regarding the flood coping procedure.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities

.1 Containment Vessel Inspection

a. Inspection Scope

The inspectors examined interior portions of the Unit 2 containment building and reviewed selected records. The observations and records were compared to the Technical Specifications (TS), ASME Boiler and Pressure Vessel Code, Article IWE of Section XI, 1992 Edition and 1992 Addenda, and 10 CFR 50.55a. The inspectors examined the interior surfaces of the containment liner and the moisture barrier at the intersection of the liner and interior concrete floor area. The inspectors also reviewed PIPs O-02-03173 and O-04-01826, coatings inspection reports, and the containment coatings health report for 2003, which documented deteriorated coatings on the liner plate in the Unit 2 reactor building. The inspectors discussed the plans for removal of deteriorated coatings during the current outage with licensee engineers and observed areas between the third and fourth levels in the Unit 2 containment building where deteriorated coatings had been removed and repaired. (See 4OA5.13 for additional discussion on reactor building coatings.)

b. Findings

No findings of significance were identified.

.2 In-Process Inservice Inspection (ISI)

a. Inspection Scope

The inspectors observed in-process ISI work activities on Unit 2 and reviewed selected ISI records. The observations and records were compared to the Technical Specifications (TS) and the applicable Code (ASME Boiler and Pressure Vessel Code, Sections V and XI, 1989 Edition, no Addenda) to verify compliance. Documents reviewed during the inspection are listed in the Attachment to this repport.

Ultrasonic (UT) examination of four inch stainless steel ASME Class 1 High Pressure Injection (HPI) pipe weld 2HP-215-3 was observed. Additionally, the inspectors observed the following Liquid Penetrant (PT) examinations:

Weld	Component
2HP-215-3	4 inch stainless steel ASME Class 1 HPI piping weld
2HP-218-5	2.5 inch stainless steel ASME Class 1 HPI piping weld
2HP-215-11	2.5 inch stainless steel ASME Class 1 HPI piping weld
2RC-271-11G	1.5 inch stainless steel ASME Class 1 Auxiliary Spray Line piping weld
2SF-114-57	Eight inch stainless steel ASME Class 2 Spent Fuel Cooling piping weld

The inspectors reviewed NDE examination reports for the following completed UT, PT and Magnetic Particle (MT) examinations:

UT Report	Component
UT-04-102	Reactor Coolant Pump (RCP) 2A1 Flywheel
UT-04-103	RCP 2A2 Flywheel
UT-04-104 (Weld Exam)	Three inch stainless steel ASME Class 2 HPI piping weld, 2-51A-31-50
UT-04-105 (Metal Lamination Exam)	3 inch stainless steel ASME Class 2 HPI piping weld, 2-51A-31-50
UT-04-106 (Metal Lamination Exam)	2.5 inch stainless steel ASME Class 2 HPI piping weld, 2HP-212-22
UT-04-107 (Weld Exam)	2.5 inch stainless steel ASME Class 2 HPI piping weld, 2HP-212-22
UT-04-108 (Base Metal Lamination Exam)	4 inch stainless steel ASME Class 1 HPI piping weld
UT-04-109 (Weld Exam)	4 inch stainless steel ASME Class 1 HPI piping weld

MT Report	Component
MT-04-007	LP Service Water Rigid Restraint, 2-14B-H19A

PT Report	Component
PT-04-039	2.5 inch stainless steel ASME Class 2 HPI piping weld, 2HP-212-22

The inspectors reviewed the weld process control reports, weld PT examination reports and radiographs of the following weld repairs completed during previous Unit 2 refueling outage EOC19:

Weld 2-HP-424-52	Three inch ASME Class II HPI piping weld
Weld 2-HP-424-53	Three inch ASME Class II HPI piping weld
Weld 2-HP-424-57	Three inch ASME Class II HPI piping weld
Weld 2-HP-424-58	Three inch ASME Class II HPI piping weld

The inspectors reviewed the pre-service ET examination reports for the replacement of the Once Through Steam Generators (OTSGs), which included use of bobbin coil and X-Probe simultaneously.

Qualification and certification records for examiners, equipment and consumables, and nondestructive examination (NDE) procedures for the above ISI examination activities were reviewed.

Three UT Indications Reports associated with potential weld indications identified during pre-outage Refueling Outage EOC20 UT examinations and accepted by the licensee, were reviewed by the inspectors. Additionally, one PIP associated with ISI activities which had been documented in the licensee's corrective action program was reviewed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator simulator training on May 19, 2004. The scenario began with the simulated unit operating at 100 percent RTP. The Unit's power level was to be reduced from 100 percent RTP to 16 percent RTP to take the Unit's main turbine offline and repair a small electro-hydraulic turbine control leak; however, at approximately 80 percent RTP, a main feedwater pump inadvertently tripped causing an integrated control (ICS) runback. The ICS runback ceased, and the unit stabilized at approximately 65 percent RTP. A main steam line break was initiated in the Reactor Building, which was determined to be from the B OTSG. The main steam leak resulted in the following: excessive heat transfer from the reactor coolant system (RCS), increasing thermal power, and an adverse containment environment. The reactor was manually tripped. Engineered Safeguards Channels 7 and 8 failed to automatically initiate. Consequently, RBS was manually initiated. The inspectors observed crew performance in terms of: communications; ability to take timely and proper actions; prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; and oversight and direction provided by the shift supervisor, including the ability to identify and implement appropriate TS actions.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's effectiveness in performing routine maintenance activities. This review included an assessment of the licensee's practices pertaining to the identification, scoping, and handling of degraded equipment conditions, as well as common cause failure evaluations. For each item selected, the inspectors performed a detailed review of the problem history and surrounding circumstances, evaluated the extent of condition reviews as required, and reviewed the generic implications of the equipment and/or work practice problem. For those systems, structures, and components (SSCs) scoped in the maintenance rule per 10 CFR 50.65, the inspectors verified that reliability and unavailability were properly monitored and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. The inspectors reviewed the following items:

- Control Room Chillers (PIPs 04-1173, 04-1455, 04-1564, 04-2603, 04-3342)

- SSF Maintenance Outage (PIPs 04-2061, 04-2118, 04-2210, 04-2271)

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluations

a. Inspection Scope

The inspectors evaluated, as appropriate, for the selected SSCs listed below: (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk; (3) that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) that maintenance risk assessments and emergent work problems were adequately identified and resolved.

- PIP 04-1945, ORAM Sentinel Discrepancies Related to Vital DC Equipment Unavailability

- PIP 04-1964, ORAM Sentinel Discrepancies Related to Control Battery Unavailability

- Orange risk condition with SSF ASW and Station ASW unavailable during Unit 2 condenser maintenance

- PIP 04-2210, Emergent SSF Emergency Diesel Generator (EDG) Unavailability

- PIP 04-2362, Orange Risk Due to SSF and Component Cooling Heat Exchanger Unavailable

- Yellow risk condition with the Lee Combustion Turbine dedicated path out of service (OOS)

- PIP 04-1611, Discrepancies Between ORAM and Unit 2 Defense in Depth Sheets

- Work Order 98656664, 1 SC-6 Adjustments (turbine/reactor trip risk)

- 3 LPSW-138 OOS with the SSF EDG unavailable

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations affecting risk significant systems, to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered; (4) if compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; and (5) where continued operability was considered unjustified, the impact on TS Limiting Condition for Operation. The inspectors reviewed the following items for operability evaluations:

- PIP 04-01846, Pressure Locking Concerns with 0 CCW-384
- PIP 04-02576, Binding of 1 BS-2 During Stroke Testing
- PIP 04-02589, Keowee Hydro Unit (KHU) Underground Path Statalarms Due to Wrong Sliding Links Being Opened
- PIP 04-02808, Feedwater Control Valves Inoperable Due to Vulnerability Related to Small Steam Line Break Concurrent with Loss of Offsite Power
- PIP 04-03093, 3 FDW-315 Failed Stroke Time Test
- PIP 04-03739, 2A Reactor Building Cooling Unit High Vibration and Fan Blade Failure

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

.1 Semi-Annual Review of the Cumulative Effects of Work-Arounds

a. Inspection Scope

The inspectors performed a cumulative review of existing operator work-arounds to determine any change from the previous review. The review also considered the effect of the work-arounds on the operators ability to implement abnormal or emergency operating procedures. The inspectors periodically reviewed PIPs and held discussions with operators to determine if any conditions existed that should have been identified by the licensee as operator work-arounds.

b. Findings

No findings of significance were identified.

.2 Risk Significant Work-Arounds

a. Inspection Scope

The inspectors reviewed an operator work-around to determine if the functional capability of the system or the human reliability in responding to an initiating event were affected. The inspectors specifically evaluated the effect of the operator work-arounds on the ability to implement abnormal or emergency operating procedures. The inspectors also assessed if the work-around could not be properly performed what impact it would have on the unit.

The work-around reviewed was documented in PIP O-04-1252, and dealt with restricted personnel access into the SSF switchgear room due to a carbon dioxide leak into the room from the fire protection carbon dioxide tank. The licensee's operability evaluation concluded that the leakage was not of sufficient size to cause problems for personnel access during various emergencies or abnormal conditions when the SSF would be relied upon.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

.1 Steam Generator Replacement Modifications

a. Inspection Scope

The inspectors reviewed various modification packages related to steam generator replacement to verify that the associated system design basis, licensing basis, and performance capability would be maintained following the modifications, as well as that the modifications would not leave the plant in an unsafe condition. The associated 10 CFR 50.59 screenings/evaluations were also reviewed for technical accuracy and to verify license amendments were not required.

The inspectors reviewed the following modification packages during the inspection:

- ON-23086 Part 000, Replacement Steam Generators, Component Modification
- ON-23086 Part AM4, Replacement Steam Generators, OTSG Replacement

b. Findings

No findings of significance were identified.

.2 Unit 1 RCP Seal Modification

a. Inspection Scope

The inspectors reviewed various modification packages related to replacement of the Unit 1 (Westinghouse) RCP seals with (Sultzer) RCP seals to verify that the associated system design basis, licensing basis, and performance capability had not changed following the modification; and that the modification had not left the plant in an unsafe condition. The inspectors had noted that the Sultzer RCP seals had experienced increased leakage during two subsequent operation cycles and multiple PIPs had been initiated. The inspectors reviewed the actions taken to determine if the licensee had adequately addressed the following attributes:

- Complete, accurate and timely identification of the problem

- Consideration of previous failures, extent of condition, generic or common cause implications

- Prioritization and resolution of the issue commensurate with safety significance

- Identification of the root cause and contributing causes of the problem

- Identification and implementation of corrective actions commensurate with the safety significance of the issue

b. Findings

Introduction: An unresolved item (URI) was identified regarding the inadequate modification of the Unit 1 RCP seals during the Fall 2000 RFO. Following the seal modification, the Number 3 seal on three of the pumps experienced increased leakage. This issue was considered to be unresolved pending further inspection to determine the effects of the increased seal leakage.

Description: The licensee performed an inadequate design change when they replaced the Unit 1 RCP Westinghouse seals with Sultzer seals during the 2000 fall outage (RFO 19). This led to increased seal leakage out of the Number 3 seal on three RCPs during operating Cycle 20 and operating Cycle 21. Between these operating cycles, the licensee attempted to correct the inadequate design but they were not successful, as Number 3 seal leakage on three RCPs reappeared during operating Cycle 21. The leakage was such that upon a loss of normal RCP seal injection/cooling, the RCP seals could heatup to a point of failure prior to establishing injection/cooling via the SSF reactor coolant makeup pump (RCMUP).

PIP O-01-01691 documented that the new seal design had not provided sufficient compression of the seal O-rings. This was due to: (1) a relatively large clearance between the seal sleeve and pump shaft; (2) an additional modification to enlarge the seal ring groove (to facilitate assembly); and (3) the Parker O-ring used in the seal package was too large in that the pump shaft was smaller than the recommended limit for the O-ring. In addition, inspection of the O-rings during RFO 21 noted that the O-rings were degraded in that "Both the O-ring and the backup ring removed from the 1B2 RCP seal upper shaft sleeve showed evidence consistent with heat induced damage. Inspection under a microscope showed that the inner diameter of the O-ring was fretted and the backup ring was cracked and embrittled at the inner surface." These deficiencies resulted in an increase in leakage out of the number three seal from less than .01 gpm to leakages between .36 to .64 gpm (all four RCPs) during operating Cycle 20. During the Spring 2002 outage (RFO 20), the licensee replaced the number three seal and corrected these problems.

Subsequently during Cycle 21, the Number 3 seal on three RCPs began leaking again. PIP O-02-03830, initiated in July 2002, documented that the RFO 19 RCP seal design change had additional inadequacies. Following completion of operating Cycle 21, the licensee found that: (1) the shaft sleeve material had a thermal expansion coefficient that was larger than the pump shaft thermal expansion coefficient, which caused increased gap and inadequate compression of the O-ring; and (2) due to the method of mounting the seal package (different than Units 2 and 3), the improper thermal expansion coefficient also caused the seal package to experience buckling/warping of the shaft sleeves, which also increased the gap. It was noted that these deficiencies caused increased leakage on the Number 3 and Number 1 seals on the 1B1 RCP. The above deficiencies resulted in increased leakage out of the Number 3 seal on three RCPs from normal leakage of less than 0.01 gpm to leakages from .51 to .74 gpm (excluding up to .4 gpm of unmonitored leakage) during operating Cycle 21. Sultzer refabricated the seal packages to address these design deficiencies during the Fall 2003 outage (RFO 21) and all of the seals were replaced.

During the licensee's review of this issue, they also identified that they had performed an inadequate root cause of the failure noted during operating Cycle 20. PIP O-02-03830 noted that there was an "inadequate independent review" performed regarding the leakage issue and that it was believed that if the review had been performed, the issue may not have recurred.

<u>Analysis:</u> This issue was determined to involve a performance deficiency because the inadequate design change led to abnormal leakage through the Number 3 seal on three of the four Unit 1 RCPs. The leakage was the result of unanticipated reduction in O-ring compression and increased clearance between the pump shaft and RCP inner sleeves. Using IMC 0612, Appendix F, "Issue Screening," the inspectors determined that the finding was more than minor because the degraded seals could affect the Initiating Events and RCS Barrier cornerstones by possibly increasing the potential for a RCP seal loss of coolant accident (LOCA). In turn, this would affect the Mitigating Systems cornerstone attribute of equipment performance reliability, in that, the capability of the SSF RCMUP could be exceeded.

The inspectors initiated the review of this finding in accordance with IMC 0609, Significance Determination Process (SDP). In order to complete the Phase 1 and if necessary, subsequent SDP analyses, this issue will require further inspection to determine if the design deficiencies could have resulted in sufficient leakage to exceed the capacity of the SSF RCMUP.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures shall be established for the selection and review for suitability of application of materials, parts, equipment and processes that are essential to the safety related functions of the structures, systems and components. Contrary to this requirement, the licensee did not ensure the proper selection of materials, parts and equipment essential for safety related functions, in that the replacement RCP seals did not have proper clearances, were not installed to limit thermal binding, and were not manufactured with materials having a compatible thermal expansion coefficient. This inadequate plant modification is captured in the licensee's corrective action program as PIPs O-01-01691 and O-02-02830. Pending further inspection to determine the effects of the increased seal leakage, this issue is being identified as an unresolved item: URI 05000269/2004003-01, Inadequate Unit 1 Reactor Coolant Pump Seal Modification.

1R19 Post-Maintenance Testing (PMT)

a. Inspection Scope

The inspectors reviewed PMT procedures and/or test activities, as appropriate, for selected risk significant systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy consistent with the application; (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function. The inspectors observed testing and/or reviewed the results of the following tests:

- PT/0/A/0400/005, SSF Auxiliary Service Water Pump Performance Test, following pump re-packing
- PT/0/A/0600/021, Standby Shutdown Facility Diesel Generator Operation, and PT/0/A/0400/005, SSF Diesel Generator Test, following jacket water maintenance
- PT/1/A/0600/013B, 1B MDEFW Pump Test following lubrication preventive maintenance (PMs)
- PT/3/A/0203/006A, 3C LPI Pump Test following scheduled maintenance
- PT/3/A/0152/012, LPI System Valve Stroke Test for 3 LP-22 following troubleshooting initial unacceptable stroke time
- PT/2/A/0608/018, Unit 2 Reactor Building Integrated Leak Rate Test following reactor building construction opening restoration
- PT/2/A/0400/007, SSF RCMUP Test following 18 month PMs

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors conducted reviews and observations for selected outage activities to ensure that: (1) the licensee considered risk in developing the outage plan; (2) the licensee adhered to the outage plan to control plant configuration based on risk; (3) that mitigation strategies were in place for losses of key safety functions; and (4) the licensee adhered to operating license and TS requirements. Between March 27, 2004, and June 16, 2004, the following activities related to the Unit 2 refueling outage were reviewed for conformance to applicable procedures and selected activities associated with each evaluation were witnessed:

- Clearance activities
- Reactor coolant system instrumentation
- Containment closure
- Refueling activities
- Plant heatup/mode changes
- Core physics testing

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of the selected risk-significant SSCs listed below, to assess, as appropriate, whether the SSCs met TS, Updated Final Safety Analysis Report (UFSAR), and licensee procedure requirements. In addition, the inspectors determined if the testing effectively demonstrated that the SSCs were ready and capable of performing their intended safety functions.

- PT/1/A/0600/012, Unit 1 Turbine Driven Emergency Feedwater Test (IST)
- PT/0/A/0251/010, Station Auxiliary Service Water Pump Test (IST)
- PT/2/A/0251/019, Unit 2 Main Steam Atmospheric Dump Valve Functional Test

- PT/1/A/0600/012, Unit 1 Turbine Driven Emergency Feedwater Test (Comprehensive Test - IST)

- PT/2/A/0151/019, Unit 2 Penetration 19 Leak Rate Test. (Containment Leak Rate)

- PT/2/A/0600/018, Unit 2 Emergency Feedwater Train Operability Test

- PT/0/A/0300/001, Unit 2 Control Rod Drive Trip Time Testing

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications

a. Inspection Scope

The inspectors reviewed documents and observed portions of the installation of selected temporary modification ON-23086-AL1, Unit 2 Steam Generator Replacement Project Temporary Power. Among the documents reviewed were system design bases, the UFSAR, TS, system operability/availability evaluations, and the 10 CFR 50.59 screening. The inspectors observed, as appropriate, that the installation was consistent with the modification documents, was in accordance with the configuration control process, adequate procedures and changes were made, and post installation testing was adequate.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Daily Screening of Corrective Action Reports

a. Inspection Scope

As required by Inspection Procedure (IP) 71152, "Identification and Resolution of Problems", and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed daily screening of items entered into the licensee’s corrective action program. This review was accomplished by reviewing copies of PIPs, attending daily screening meetings, and accessing the licensee’s computerized database.

b. Findings

No findings of significance were identified.

.2 Focused Review

a. Inspection Scope

The inspectors performed an in-depth review of two issues entered into the licensee's corrective action program. The samples were within the mitigating systems cornerstone and involved risk significant systems. The inspectors reviewed the actions taken to determine if the licensee had adequately addressed the following attributes:

- Complete, accurate and timely identification of the problem

- Evaluation and disposition of operability and reportability issues

- Consideration of previous failures, extent of condition, generic or common cause implications

- Prioritization and resolution of the issue commensurate with safety significance

- Identification of the root cause and contributing causes of the problem

- Identification and implementation of corrective actions commensurate with the safety significance of the issue.

The following issues and corrective actions were reviewed:

- PIPs O-04-2365, O-01-2827; Documented Tornado Missile Protection of the Unit 3 Control Room

- PIPs O-03-3618, O-03-7864, and O-04-1495; Documented Bypass Flow Deficiencies with Unit 3, 1 and 2 RBESs, respectively

b. Findings

(1) Introduction: An unresolved item was identified related to the Improper use of 10 CFR 50.59 to change the UFSAR tornado missile design requirements of the Unit 3 control room.

Description: The licensee's design basis document OSS-0254.00-00-3007, Design Basis Specification for the Auxiliary Building, Revision 1, dated July 25, 1996, noted that a 1970 memo had removed the requirements for tornado missile protection for the Units 1, 2 and 3 control rooms. In early 2001, the inspectors questioned the licensee as to how this was possible, since UFSAR Table 3-23, Auxiliary Building Loads and Conditions, specified that the Units 1, 2, and 3 control rooms be missile protected. Of particular interest was Unit 3, for unlike Units 1 and 2, the Unit 3 control room has exterior walls that could readily be subjected to tornado loading (i.e., wind force, differential pressure, and missiles). Resolution of this issue was further addressed in 95002 Supplemental Inspection Reports 05000269,270,287/ 2001009 and 05000269,270,287/2002007, where it was identified as URI 05000287/ 2002007-02, Unit 3 Control Room Wall Not Designed to Withstand Tornado Loads.

In early April 2004, the inspectors determined that the licensee had inappropriately performed a 10 CFR 50.59 evaluation to change the UFSAR licensing basis. The 50.59 evaluation, dated December 11, 2003, among other things, would revise UFSAR Table 3-23, to allow low probability of missile strikes on the Unit 3 control room as a means of protection. The original UFSAR Table 3-23 specified that the Unit 3 control room would be protected from the effects of a tornado generated missile of 8 inches in diameter by 12 feet long piece of wood, weighing 200 pounds and traveling at 250 miles per hour, as well as protected from a 2000 pound automobile, traveling at 100 miles per hour with a 20 square foot impact area, for 25 feet above grade. Protection was to be provided by structure design or barriers, not by a low probability of strike. The licensee stated in the 50.59 evaluation that "Duke has concluded from research on this structure (control room) that the wall is required to be protected from tornado missiles." The licensee also stated that "The principle design criteria for the Oconee Units was developed in consideration of the seventy General Design Criteria for the Nuclear Power Plant Construction Permits proposed by the Atomic Energy Commission."

Guidance for making 10 CFR 50.59 changes is provided in NEI 96-07, Revision 1, dated November 2000. The NEI guidance states "Departures from design, fabrication, construction, testing and performance standards as outlined in the General Design Criteria (Appendix A to Part 50) are not compatible with a no more than minimal increase standard." This would dictate that the 10 CFR 50.59 process could not be used to make the change to the UFSAR and a license amendment would be required.

During subsequent discussions, the licensee indicated that a license amendment would be submitted. At the close of the present inspection period (June 26, 2004), the licensee had still not provided the NRC a schedule for when a license amendment request would be submitted to the NRC.

Analysis: This issue was determined to involve a performance deficiency because the licensee misapplied the criteria of 10 CFR 50.59 and concluded that prior NRC approval was not required when such a conclusion could not be supported since the "no more than minimal increase" standard could not be used. The finding was more than minor because the Unit 3 control room physical barrier was degraded and during a tornado event could result in the loss of personnel and systems needed to respond to initiating events (effects of a tornado) to prevent undesirable consequences.

The inspectors reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The consequence of the lack of protection from a tornado was assessed through the Phase 1 of the SDP. The inspectors answered the question, "Does this finding screen as potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event using the criteria on page 3 of the worksheet," as "Yes," because, during a design basis tornado, the Unit 3 control room would not physically protected. Loss of the control room during a tornado could lead to missile debris and water causing a trip, as well as adversely affecting the control of multiple systems and trains of systems. In addition, the ability of control room operators and the damage control teams stationed in the Unit 3 control room could be adversely affected. Based on these conclusions, the Phase 1 sheet indicated that a Phase 3 analysis was required.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that conditions adverse to quality are promptly identified and corrected. Contrary to this requirement, since being initially identified in 1996, the licensee has failed to promptly correct the issue related to the requirement to protect the Unit 3 control room from tornado generated missiles in that with the most recent attempt, the licensee improperly used the 10 CFR 50.59 process to change UFSAR, Table 3-23, to allow use of low probability of impact as a means of protection for the Unit 3 control room from tornado generated missiles. This improper use of 10 CFR 50.59 issue is captured in the licensee's corrective action program as PIP O-04-02365. Pending completion of the Phase 3 analysis, this issue is being identified as: URI 05000287/2004003-02, Inadequate Corrective Action Related to the Improper Use of 10 CFR 50.59 to Change the UFSAR Tornado Missile Design Requirements of the Unit 3 Control Room.

(2) Introduction: A Green non-cited violation (NCV) was identified for inadequate quality control (QC) inspections of the Oconee Units 1, 2 and 3 RBESs, in that, gaps in the RBES structures were not discovered during previous QC inspections.

Description: On June 1, 2003, with Unit 3 in Mode 5 preparing for a reactor startup, a QC inspector performing a final inspection of the RBES per Enclosure 13.6 of MP/0/A/1800/105 identified problems associated with the RBES configuration (fitup). Two gaps had been discovered in the upper corners of the RBES. Each gap was approximately 0.25 inches in width and 1 inch in length. In PIP O-03-3618, the licensee concluded, that the failure to discover the gaps could be attributed to both poor lighting in the vicinity of the RBES and.....becoming complacent while performing this task, i.e. no modifications had been performed to this screen and past inspections had not revealed any discrepancies." Prior to June 1, 2003, the licensee's QC department had satisfactorily inspected the Unit 3 RBES on December 8, 2001, as well as, at the conclusion of previous refueling outages.

On August 8, 2003, the Duke Energy Corporation submitted a response to NRC Bulletin 2003-01, Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors. In that response, interim compensatory measure Number 6 was to ensure that the RBES screens were free of adverse gaps or breaches. The licensee stated that this compensatory measure was already being met by their current inspection practices. The licensee's stated that RBES inspections are performed every refueling outage and consisted of three different, independent inspections. The RBES are inspected by maintenance per procedure MP/0/A/1800/105, by QC per the same procedure, and by the RBS system engineer as part of the Engineering Support Program. MP/0/A/1800/105 requires inspection for debris, gaps or tears in the screen, missing cover plate bolts, and openings in and around the sump cover in excess of the screen mesh size, while the RBS system engineer inspects the RBES visually for debris, damage and configuration.

On December 2, 2003, with Unit 1 in Mode 5 preparing for a reactor startup, a system engineer performing a RBS system walkdown identified four gaps in the RBES structure. The gaps were located in the upper corners of the RBES and were approximately 0.25 inches in width and 1.5 inches in length. In PIP O-03-7864, the licensee noted that previous inspection activities had not been adequate to ensure that the RBES were free of adverse gaps and breaches. Also, in PIP O-03-7864, the RBS system engineer stated that, “the fitup of the screen has not been a focus of the inspections by the sump engineer. Inspections have typically focused upon the main flow path into and through the sump structure, looking for general condition of the structure and major design features such as curbs, cover plates, grating, and screen. Loose fitup at the corners of the structure was not recognized as a potential problem until the inspection of the Unit 3 emergency sump by QC during the [end of cycle] EOC - 20 refueling outage in the Spring of 2003. Similar discrepancies were discovered during that inspection as document in References 8.4 [PIP O-03-3618].” Additionally, the licensee concluded, that “...the gaps present at the corners of the Unit 1 RBES structure were likely to have been present during the previous cycle, if not, for the entire life of the plant...”, as “... the configuration (fitup) of the corners of the sump was not modified during the [Unit] 1 EOC-21 refueling outage and most likely has not been modified for the life of the plant.” Prior to December 2, 2003, the licensee’s QC department had satisfactorily inspected the Unit 1 RBES per Enclosure 13.6 of MP/0/A/1800/105 on April 21, 2002, as well as at the conclusion of previous refueling outages.

On March 20, 2004, with Unit 2 in Mode 4 preparing to commence a refueling outage, a system engineer performing a RBS system walkdown identified four gaps in the RBES structure. The gaps were located in the upper corners of the RBES and ranged from approximately 0.15625 to 0.25 inches in width and from approximately 0.25 to 1.25 inches in length. A 1 inch gap was discovered at the bottom of the RBES screen where the screen had separated from its structural backing. In PIP O-04-1495, the licensee again identified that previous inspection activities had not been adequate to ensure that the RBES were free of adverse gasp and breaches. Also, in PIP O-04-1495, the RBS system engineer stated that, “the fitup of the screen has not been a focus of the inspections by the sump engineer. Inspections have typically focused upon the main flow path into and through the sump structure, looking for general condition of the structure and major design features such as curbs, cover plates, grating, and screen. Loose fitup at the corners of the structure was not recognized as a potential problem until the inspection of the Unit 3 emergency sump by QC during the refueling outage 3 EOC-20 in the Spring of 2003. Similar discrepancies were discovered during that inspection and subsequent inspection of Unit 1 as document in References 8.4 and 8.5 [PIP O-03-3618 and PIP O-03-7864].” Additionally, the licensee concluded, that “... the gaps present at the corners of the Unit 2 RBES structure were likely to have been present during the previous cycle, if not, for the entire life of the plant ...”, as “... the configuration (fitup) of the corners of the sump was not modified during 2 EOC-20 refueling outage and most likely has not been modified for the life of the plant.” Prior to March 20, 2004, the licensee’s QC department had satisfactorily inspected the Unit 2 RBES per Enclosure 13.6 of MP/0/A/1800/105 on November 17, 2002, as well as, at the conclusion of previous refueling outages.

<u>Analysis</u>: The inspectors reviewed this finding in accordance with IMC 0609, “Significance Determination Process.” The consequence of inadequate QC inspections was assessed through Phase 1 of the SDP. The finding was considered to be more than minor because it affected the mitigating systems cornerstone attribute of equipment performance reliability, in that, the inadequate QC inspections failed to identify RBES bypass flowpaths for debris to affect downstream ECCS components during RBES recirculation. However, because the gaps were small, the increase in the probability of debris bypassing the RBES screens was considered to be low.

Consequently, the Mitigating Systems questions were all answered "No", and the finding screened out of the Phase 1 SDP analysis as Green (very low safety significance).

Enforcement: 10 CFR 50 Appendix B, Criterion X, Inspection, requires ,in part, a program for inspection of activities affecting quality shall be established and executed verify conformance with the documented instructions, procedures, and drawings for accomplishing the activity. Contrary to the above, the licensee failed to perform adequate QC inspections of the RBESs in all three Oconee Units, in that gaps, which may have existed since initial licensing of the plants, were not discovered during previous QC inspections. Because this was determined to be of very low safety significance and has been entered into the licensee's corrective action program as PIP O-03-3618, PIP O-03-7864, and PIP O-04-1495, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 050000269, 270,287/2004003-03: Inadequate QC Inspections of Reactor Building Emergency Sumps.

.3 Correction of Operator Training Issues

a. Inspection Scope

During the period of April 20-21, 2004, the inspectors reviewed three PIPs (O-02-03709, O-03-04450, and O-03-06589) and conducted interviews to determine if problems were being properly identified and entered into the Corrective Action Program (CAP) for resolution. The review primarily focused on Operator Training's evaluation of performance observations against management's expectations, along with the facility's corrective actions associated with NRC comments that were documented in NRC Initial License Examination report 2003-301. The inspectors reviewed documentation regarding the restoration of offsite or emergency power, isolating steam going to the condenser on a turbine bypass valve failure, application of "If At Any Time" (IAAT) steps, procedure implementation errors resulting from operators being excessively challenged by the procedures, actuation of ES Channels 7 and 8 when they failed to actuate on high Reactor Building (RB) pressure, excessive double negatives in procedures, and the operator's overall ability to execute procedures smoothly and in a timely manner. The inspectors observed the administration of a simulator operating test that involved a unit blackout and a loss of feedwater in order to validate the recent changes that were made to the facility's Emergency Operating Procedure (EOP) Blackout procedure. Licensee documents reviewed during the inspection are listed in the Attachment to this report. Additionally, the inspectors reviewed an issue that was identified (Resident Inspection Report 2003009) concerning an inappropriate reinsertion of alternate boron injection back into the EOPs. The inspectors assessed whether the licensee's root cause evaluation and associated corrective actions were appropriate, timely, and relative to the identified problem(s).

b. Findings

No findings of significance were identified.

.4 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a trend review to determine if trends were identified outside the corrective action program that could indicate the existence of a more significant safety issue. The inspector's review was focused on repetitive equipment issues, but also considered the results of daily inspector corrective action program item screening discussed above, licensee trending efforts, and licensee human performance results. The inspector's review nominally considered the six-month period of January 2004 through June 2004, although some examples expanded beyond those dates when the scope of the trend warranted. The review included the following areas/documents:

- PIP and department trend reports for 4th quarter 2003 and 1st quarter 2004
- NRC performance indicators and departmental performance measures
- equipment problem lists
- maintenance rework trending
- departmental problem lists
- system health reports
- quality assurance audit /surveillance reports
- self assessment reports
- maintenance rule program reports including a(1) list
- corrective action backlog lists

b. Observations and Findings

In general, the inspectors found that the licensee's trending of issues has been effective in identifying and preventing problems from becoming more significant.

One trend was identified by the inspectors during this six-month period. The trend involved the identification of deficient QC/QA inspection activities where QC/QA had accepted conditions as acceptable and subsequently the conditions were identified as not having been acceptable. The observation included five examples as follows:

- The inspectors identified a Green NCV for inadequate QC inspections of the Unit 1, 2 and 3 RBES. Previous inspections failed to identify gaps and breeches in the RBES screen structures and the inspections were documented with no deficiencies. This example is documented in section 4OA2.2 of this report.

- The licensee identified that technicians and QC personnel were artificially inducing environmental conditions (temperature and humidity) with a heat gun, in order, to facilitate the application of qualified coatings within the Unit 2 RB. QC documented that conditions were acceptable for application of the coatings, although the induced environmental conditions were not being maintained for the coating cure time (24 hours). This example was documented in PIP O-04-3528.

- The licensee determined that procurement quality control measures associated with the vendor supplied O-Rings for the Unit 1 RCP seals were inadequate. Specifically, the vendor QA program documented that the O-rings had the proper hardness, although the O-rings were not being tested using the correct hardness test. As a result, O-rings of insufficient hardness were installed in the Unit 1 RCPs. This example was documented in PIP O-03-08163.

- The inspectors identified a Green NCV for an inadequate procedure which resulted in the inadequate installation and QC inspection of an FME Barrier in the 1B RCS Hot Leg during OTSG replacement. QC documented that the barriers were properly installed, although they could not see the entire barrier sealing area. This example was documented in Inspection Report 2003-005.

- The inspectors identified a Green NCV for inadequate procurement quality control measures associated with one non-conforming CRDM Flange Ring installed on Unit 2 and the discovery of 68 non-conforming CRDM Flange Rings and 552 non-conforming CRDM Hold Down Bolts prior to their installation on Unit 3. The vendor's QA program documented that the CRDM flange ring and hold down bolts met ASME criteria, although they did not. This example was documented in Inspection Report 2003-003.

The inspectors concluded that these five examples constituted an adverse trend associated with deficient QC/QA inspection activities. The licensee has documented this adverse trend in PIP O-04-4770.

4OA3 Event Followup

(Closed) Licensee Event Report (LER) 05000287/2004-01, Unit 3 Trip Due to Foreign Material in Turbine Electro-Hydraulic Control System. The inspectors reviewed the circumstances surrounding the Unit 3 trip and the licensee's corrective actions during the previous inspection period and a Green finding was documented in Inspection Report 05000269,270,287/2004002. There were no additional concerns identified. This LER is closed.

4OA5 Other Activities

.1 (Closed) Temporary Instruction (TI) 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants. TI 2515/154, Phase I and Phase II, were completed during this inspection period. Appropriate documentation was provided to NRC management as required.

.2 Steam Generator Replacement Project (SGRP) Inspection Overview

This inspection report documents completion of inspections required by Inspection Procedure (IP) 50001, Steam Generator Replacement Inspection, some of which were completed in accordance with baseline inspection procedures. The table below identifies and correlates specific IP 50001 inspection requirements examined during this inspection period with the corresponding sections of this report.

IP 50001 Section	Inspection Scope	Section of This Report
02.02.a.	SG replacement engineering and technical support	1R17
02.03.e.4.	Installation, use, and removal of temporary services	1R23 4OA5.7
02.03.e.3.	Implementation of foreign material exclusion controls	4OA5.3
02.03.e.2.	Implementation of radiation protection controls	4OA5.3
02.04.1	Containment testing	1R19
02.04.2	Post-installation inspections and verifications program	4OA5.4
02.04.3 02.04.4	Leakage testing (VT-2 inspections)	4OA5.4
02.04.5	Calibration and testing of instrumentation	4OA5.5
02.03.d	Restoration of temporary containment opening	4OA5.6
02.03.a	Welding, nondestructive examination	4OA5.8
02.04.7	Preservice inspection of welds	4OA5.8

.3 SGRP Foreign Material Exclusion (FME) Controls, Radiation Protection Controls

a. Inspection Scope

As required by IP 50001 Section 02.03.e, throughout this inspection period, the inspectors routinely inspected the following activities as they occurred:

- Implementation of foreign material exclusion controls. The inspectors periodically observed the implementation of FME controls for various RCS and steam generator openings to ensure the openings were sealed to prevent the introduction of debris into these systems.

- Implementation of radiation protection controls. The inspectors performed walkdowns of the reactor building to verify that the appropriate radiation postings were displayed and that radiation protection (RP) personnel were assigned to provide RP job coverage.

b. Findings

No findings of Significance were identified.

.4 Post-installation Inspections and Verifications Program

a. Inspection Scope

As required by IP 50001 Section 02.04.2., the inspectors reviewed the licensee's post-installation inspections and verifications program. The inspectors reviewed the Unit 1 Startup Test Matrix and the SGRP Integrated Startup Plan to verify that the appropriate post-installation testing was identified and scheduled accordingly including the required ASME code VT-2 inspections and operational steady state data collection. Also, procedure MP/0/A/1720/016, System/Component Pressure Test Controlling Procedure, was reviewed to verify that required post-installation were performed and documented following OTSG replacement.

b. Findings

No findings of significance were identified.

.5 Calibration and Testing of Instrumentation

a. Inspection Scope

As required by IP 50001 Section 02.04.5., the inspectors reviewed the completed calibration test procedures for the emergency feedwater steam generator level, SSF auxiliary service water steam generator level, steam generator startup level, and steam generator full and operating range level transmitters for the A and B replacement steam generators. The inspectors reviewed the test documentation to verify that the calibrations were performed in accordance with the licensee's approved test procedures and to ensure that the "as left" transmitter output were within the acceptance criteria. The following calibration procedures were specifically reviewed:

- IP/0/A/0275/014, Steam Generator Startup Level Instrument Calibration
- IP/0/A/0275/019 B, Emergency Feedwater System Emergency Steam Generator Level Instrument Calibration
- IP/0/A/0275/015, Steam Generator Full and Operate Range Levels Instrument Calibration
- IP/0/A/0375/001 B, SSF Auxiliary Service Water System Steam Generator Level Instrument Calibration

b. Findings

No findings of significance were identified.

.6 Containment Restoration Activities

a. Inspection Scope

The inspectors examined restoration activities associated with the temporary construction opening (approximately 23.5 feet by 25 feet) in the containment liner, as detailed in the licensee's Modification Package ON-23086, Part AS9, Containment Opening, Revision 2.

Activities associated with containment liner plate welding were observed/reviewed and compared with the applicable codes (ASME Boiler and Pressure Vessel Code (B&PV), Section VIII, 1998 Edition with no Addenda and Section XI, 1989 Addenda with no Addenda) and Oconee Specifications OSS-0139.00-00-0001 and OSS-0139.00-00-0004. For the liner plate welds (LP-1, LP-2, LP-3, and LP-4), the inspectors: observed in-process welding inside and outside surfaces, including weld material control; visually inspected a portion of the back-gouged surface (outside) and the final weld surfaces (inside and outside) ; observed a portion of the in-process magnetic particle (MT) inspection of the back-gouged surface and reviewed the MT inspection reports for the final weld surfaces for all 4 welds; and reviewed the final radiographic (RT) film, including rejects and repair film. In addition to observation of in-process work, the inspections included: review of the welding procedure specification, including the supporting procedure qualification records; review of welder qualification records; review of welding material receipt inspection and certification records; review of in-process Weld Data Cards; review of Quality Control (QC) involvement in the welding process; and review of QC and nondestructive examination (NDE) personnel qualification and certification records.

For restoration of the reinforced concrete, the inspectors reviewed activities associated with installation of the containment opening reinforcing bar (rebar) and compared activities with the applicable Codes (ACI 318-63, Part IV-B, Building Code Requirements for Reinforced Concrete Institute, 1963; AWS D1.4-98, Structural Welding Code-Reinforcing Steel; and ASME Section III, Division 2, 1995 Edition, 1995 Addenda). The inspection included review of the rebar splice procedure and observation of a sample of 46 (21 horizontal and 25 vertical) re-bars which had the Barsplice swaged couplers mechanically spliced to one end of the bars. In addition, the inspectors reviewed qualification records for nine splicers and two QC inspectors (civil and IWE/IWL endorsements), including tensile test results for the splicer's qualification coupons.

Relative to installation of concrete, the inspectors witnessed placement of concrete in the containment wall to restore the temporary construction opening. The inspectors examined the reinforcing steel to ensure it was installed in accordance with design requirements, observed the concrete forms to ensure tightness and cleanliness, and that reinforcing steel was clean. The inspectors reviewed placement activities to ensure that activities pertaining to concrete delivery time, free fall, flow distance, layer thickness and concrete consolidation conformed to industry standards established by the American Concrete Institute. Concrete batch tickets were examined to ensure that the specified concrete mix was being delivered to the site. The inspectors also witnessed testing of the plastic concrete for slump, air, and temperature, unit weight, and molding of the concrete cylinders for testing. Reviews were performed to ensure concrete testing was performed and the cylinders were molded in accordance with applicable American Society for Testing and Materials (ASTM) requirements. In addition, the inspectors reviewed activities to ensure that concrete testing was performed by qualified inspectors from an independent testing company, and that concrete placement activities were continuously monitored by licensee and contractor quality control and quality assurance personnel.

The inspectors reviewed concrete batching activities including proper storage and separation of materials, and temperature controls. The inspectors reviewed results of quality control acceptance testing performed on materials (cement, Komponent, fine and coarse aggregate, and admixtures) used for batching the concrete. The inspectors also reviewed records documenting inspection of the concrete batch plant and the concrete truck mixers. Activities were reviewed to determine if the contractor's inspection of the trucks and batch plant were performed in accordance with the guidance of the National Ready Mixed Concrete Association (NRMCA); the batch plant scales were calibrated in accordance with NRMCA recommendations; and mixer efficiency tests were performed on the truck mixers in accordance with ASTM C-94. The inspectors reviewed the concrete mix data to ensure that mix proportions for delivered concrete were selected based on trial concrete mix results, that QC acceptance criteria for the plastic concrete were based on the trail mixes, and that the trail mix met concrete strength requirements.

The inspectors also reviewed Modification Package ON-23086, Part AS9, Containment Opening, Revision 2, to verify that the modification was properly evaluated in accordance with 10 CFR 50.59.

b. Findings

No findings of significance were identified.

.7 Review of SGRP Lifting and Transportation

a. Inspection Scope

The inspectors reviewed the adequacy of the SGRP rigging and handling program as described in ON-23086 AS6, "Steam Generator Rigging and Handling," Rev. 2 to verify their compliance with regulatory requirements, appropriate industrial codes, and standards, ANSI N45.2.15, Generic Letter 81-07 and NUREG 0612.

The inspectors examined portions of the SGRP lifting equipment necessary to perform steam generator rigging and transport, design evaluation/erection/use of the Outside Lift System (OLS) and Temporary Lifting Device (TLD), Hatch Transfer System (HTS), and a Self Propelled Modular Transport (SPMT). The inspectors reviewed the applicable engineering design, modification and analysis associated with SG lifting and rigging including: crane and rigging equipment, steam generator drop analysis, safe load paths, and load drop protection. The inspectors reviewed to determine if appropriate functional tests were performed or documented in accordance with the ASME/ANSI code for both the TLD, OLS, and lifting links. The inspectors reviewed to determine if the TLD and OLS cranes were operated by qualified and certified personnel, and that wire ropes and synthetic slings used during heavy lifts were appropriately tested and inspected prior to use. The inspectors reviewed to determine if the maximum anticipated loads to be lifted would not exceed the capacity of the lifting equipment and supporting structures.

The inspectors reviewed procedures, drawings, work packages and lifting documents that controlled the SGRP, which are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.8 Steam Generator Removal and Replacement Welding Activities

a. Inspection Scope

The inspectors reviewed portions of the fit up, welding and post weld heat treatment (PWHT) activities related to the SG replacement activities involving portions of RCS, Main Steam (MS) System and Feedwater (FDW) System piping. The replacement RCS piping was procured in accordance with ASME Section II Part A, 1998, no addenda as directed by ANSI B31.1, 1998. The reinstallation and inspection of piping activities were performed under ASME Section III, Subsection NB, NC, 1989 no addenda, which is considered to be an acceptable substitute to the original B31.1 design code. The inspectors reviewed the SGRP and RVHRP Code Reconciliation (Other than Reactor Coolant System), 5/30/03 and SGRP and RVHRP Code Reconciliation (Reactor Coolant System), 4/7/03, for code compliance with the original site building code.

The inspectors reviewed records for calibration, examination results, fit-up, welding, certifications of personnel, materials, as-built configuration, and held discussions with cognizant engineering personnel. The inspectors reviewed WPS GT/1.1, Rev. 0E1, ASME Section IX Welding Procedure Specification and WPS GT/3.1, Rev. 0E1, ASME Section IX Welding Procedure Specification that provided the specifications for the automated welding performed on the RCS, FDW and MS piping.

The inspectors examined selected records and reviewed procedures to evaluate the licensee's training and qualification efforts for personnel performing cutting, machining, welding and NDE. The inspectors also reviewed the programs and compared them with the regulatory requirements and codes that were utilized during the SGRP.

To verify that the NDE activities (including UT, PT, and RT examinations) showed that the welds were free of rejectable indications, the inspectors reviewed NDE documentation including radiographs of completed RCS hot leg and cold legs, FDW and MS welds to verify compliance with ASME Code Section III, Class 1, 1989 Edition, No Addenda, ASME Section V, 1989 Edition, No Addenda, and ASME Section XI, 1998 Edition, 2000 Errata.

The inspectors reviewed NDE records which included Work Packages, NDE Test Reports UT, PT and RT, equipment certifications, consumables certifications, NDE examiner certification and visual acuity documentation. For the RT exams the inspectors reviewed for proper penetrameter or wire type, size, placement, and sensitivity, as well as film density, identification, quality, and weld coverage. Records were reviewed for completeness, accuracy and technical adequacy. The radiographs were examined for both film quality and acceptability.

The inspectors reviewed to determine if pre-service and baseline eddy current examinations were in performed in compliance with NRC Regulatory Guide 1.83, Oconee TS, and Section XI of the 1998 ASME Code with 2000 Addenda. The inspectors reviewed the baseline eddy current data as contained in the Preservice Eddy Current Inspection, BWC-TR-2003-012, Rev. 0 and BWC-TR-2003-013 Rev. 0 reports. The inspectors reviewed aspects of the examination program for the B&W OTSGs, which included use of bobbin coil and X-probe simultaneously on 100% of the tubes from tube-end to tube-end. The inspectors reviewed for wall loss indications in either generator.

b. Findings

No findings of significance were identified.

.9 (Closed) TI 2515/152, Reactor Pressure Vessel Lower Head Penetration Nozzle Inspection - Unit 2

a. Inspection Scope

The inspectors reviewed activities associated with the inspection of the Unit 2 reactor vessel (RV) lower head penetrations in response to NRC Bulletin 2003-02. The guidelines for the inspection are provided in NRC TI 2515/152, Reactor Pressure Vessel (RPV) Lower Head Penetration Nozzle Inspection (NRC Bulletin 2003-02).

The inspection included a review of the licensee’s procedures, assessment of inspection personnel training and qualification, and observation and assessment of video documentation of the lower head inspections. Discussions were also held with licensee engineering personnel. The inspectors reviewed results of the licensee’s 100 percent Bare Metal Visual (BMV) examination. The activities and documents listed below were examined to verify licensee compliance with regulatory requirements and gather information to help the NRC staff identify possible future regulatory positions and generic communications.

Specifically, the inspectors reviewed and observed:

- MP/0/A/1150/030, Reactor Vessel - Lower Head Penetrations - Visual Inspection, Revision 2
- Critical Evolution Plan, Unit 2 EOC-20 Under Vessel Inspection
- PIP O-04-1640, Results of [Unit 2] reactor vessel lower head bare metal inspection
- Oconee Training Records, Incore Nozzle Bare Metal Inspection Course
- Video documentation of BMV exam of Unit 2 Reactor Vessel Lower Head

b. Findings

TI 2515/152 Reporting Requirements:

1.1 Was the examination performed by qualified and knowledgeable personnel?

The BMV examination of the RV lower head was conducted by licensee personnel with prior experience with the identification of boric acid deposits during previous inspections of the upper head penetrations for all three units. The lower head specific training documentation for the inspection personnel performing the BMV examinations were verified. The inspectors verified that operating experience from the South Texas Project Unit 1 examination results were incorporated into the inspectors' training, including photographs of the leaking penetrations. The inspectors found that the licencee's inspection personnel were very knowledgeable and experienced with conducting visual examinations of reactor vessel head penetrations.

1.2 Was the examination performed in accordance with demonstrated procedures?

The inspectors reviewed the applicable inspection procedures and verified they had been reviewed and approved through the licensee's procedure review process.

The BMV examination was performed in accordance with licensee procedure number MP/0/A/1150/030, Reactor Vessel - Lower Head Penetrations - Visual Inspection, Revision 2.

1.3 Was the examination able to identify, disposition, and resolve deficiencies?

The inspectors reviewed the procedures controlling the 100 percent Bare Metal VT-2 examination techniques, and determined that they provided adequate guidance to ensure that they would be able to identify, disposition and resolve relevant deficiencies in the RV lower head penetration materials.

1.4 Was the examination capable of identifying pressure boundary leakage and/or RPV lower head corrosion as described in BL 2003-02?

Based upon review of the results for the BMV examination, procedures, qualifications, appropriate lighting, and sensitivity requirements, the inspectors determined that the licensee was capable of identifying pressure boundary leakage and boric acid corrosion, if present.

2.0 Could small boron deposits, as described in the bulletin, be identified and characterized?

With the available lighting on the video inspection equipment and the clarity of the picture, the inspectors were able to verify that there were no indications of lower vessel head penetration leakage. Had boron deposits been present, as described in the bulletin, they could have been readily identified and characterized.

3.0 How was the visual inspection conducted?

The licensee utilized a combination direct visual observation with closeup video documentation.

4.0 How complete was the coverage?

Full 360 degree coverage around the circumference of all nozzles was achieved.

5.0 What was the condition of the reactor vessel lower head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

Prior to the lower head inspection all the insulation was removed, and the reactor vessel bottom head was entirely accessible for the BMV inspection. The lower vessel head had been originally coated with a silver metallic paint which exhibited uniform peeling and flaking on the vessel surface. Metal surface corrosion was identified on the lower vessel head exposed surfaces. There was no corrosion identified on the in-core guide tubes. Each of the 52 penetrations was videoed such that a complete 360-degree view of each penetration was obtained. Boron deposits were not noted by the inspectors on any of the lower pressure vessel surfaces. The inspectors did not see any “popcorn” type boric acid crystals at the penetration/vessel interface. There was no wastage, corrosion or cracks that needed repair. The inspection results were documented in MP/0/A/1150/030. The inspectors reviewed the video of the bottom head inspection to verify the licensee’s inspection results, and held discussions with the appropriate engineering and examination personnel.

6.0 What material deficiencies (associated with the concerns identified in the bulletin) were identified that required repair?

No material deficiencies were identified.

7.0 What, if any, impediments to effective examinations were identified.

There were no significant items that could impede effective examinations. The licensee was able to inspect 360 degrees around each of the 52 lower head penetration nozzles.

8.0 Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components above the RPV lower head?

There was no indication of boric acid leaks from pressure-retaining components above the RPV lower head.

9.0 Did the licensee take any chemical samples of any deposits?

There were no deposits present; therefore, no chemical samples taken.

10.0 Is the licensee planning to do any cleaning of the head?

The licensee pressure washed the lower head following the inspection to remove the loosely adherent metallic paint and video documented the as left condition.

11.0 What are the licensee's conclusions regarding the origin of any deposits present?

There were no deposits noted and therefore the licensee concluded that no leakage of the Unit 2 lower head penetrations exists.

.10 (Open) TI 2515/153, Reactor Containment Sump Blockage Inspection - Unit 2

a. Inspection Scope

The inspectors reviewed activities associated with the inspection of the Unit 2 containment sump blockage concerns in response to NRC Bulletin2003-01. The guidelines for the inspection were provided in NRC TI 2515/153, Reactor Containment Sump Blockage (NRC Bulletin 2003-01).

The inspection included a review of the licensee's response describing interim compensatory measures (Option 2), inspection of the containment emergency sump, observations of repairs performed on the emergency sump, and a detailed inspection of sections of containment to identify debris still left in containment following the refueling outage.

Specifically, the inspectors reviewed and observed:

- The licensee's response to NRC Bulletin 2003-01 documented in a letter dated August 7, 2003
- PIP O-03-4376, which tracked Bulletin 2003-01 and the associated corrective actions
- Repairs to the containment emergency sump documented in work orders WO-98657173

b. Findings

TI 2515/153 Inspection of Responses Describing Interim Compensatory Measures (03.02)

The following interim compensatory measures were reviewed during this inspection period. All other measures were reviewed by the inspectors during the Unit 1 EOC-21 refueling outage and documented in inspection report 2003-05.

1.9 The inspectors verified that a Technical Support Center guidance document was developed to direct actions in the event of RBES blockage.

5. The inspectors verified that the reactor vessel annulus flow path (drains) were flushed during the 1 EOC-21, 2 EOC-20, and 3 EOC-20 refueling outages (Fall

2003, Spring 2004 and Spring 2003, respectively) to ensure no blockages existed that would prevent free flow to the RBES. PIP O-03-4376 documented the results of these flushes.

TI2515/153 Inspection of the Containment Sump and Condition Assessment (03.03)

To be inspected during the next inspection period.

TI2515/153-05 Reporting Requirements

a. A walkdown of the Unit 2 containment was conducted during the 2 EOC-20 refueling outage by the licensee to quantify potential debris sources.

b. Not applicable

c. A walkdown will be performed on Unit 3 when it enters its next refueling outages

d. The walkdown did check for gaps in the emergency sump screens and plant design prohibits major obstructions in the flow paths to the sumps

e. There are no advance preparations being made at the present time to expedite any sump related modifications.

.11 (Open) TI 2515/156, Offsite Power System Operational Readiness

a. Inspection Scope

The inspectors collected data from licensee maintenance records, event reports, corrective action documents and procedures and through interviews of station engineering, maintenance, and operations staff, as required by TI 2515/156. The data was gathered to assess the operational readiness of the offsite power systems in accordance with NRC requirements such as Appendix A to 10 CFR Part 50, General Design Criterion (GDC) 17; Criterion XVI of Appendix B to10 CFR Part 50, Plant TS for offsite power systems; 10 CFR 50.63; 10 CFR 50.65 (a)(4), and licensee procedures.

b. Findings

No findings of significance were identified. Based on the inspection, no immediate operability issues were identified. In accordance with TI 2515/156 reporting requirements, the inspectors provided the required data to the headquarters staff for further analysis. This TI will remain open pending completion of that analysis.

.12 (Closed) Apparent Violation (AV) 05000269,270,287/2004009-01, Failure to Promptly Identify and Correct Seal Water Leakage Contamination of the SSF ASW Pump Inboard Bearing Lube Oil Water Contamination. This issue was discussed in detail in Inspection Report 05000269,270,287/2003004 and identified as a preliminary greater than Green finding/AV in Inspection Report 05000269,270,287/2003009 (i.e., NRC “Choice Letter” dated February 24, 2004). Subsequently, the licensee performed bearing testing commensurate with the as-found oil conditions and bearing loading. The licensee formally communicated the results of this testing to the NRC in a letter dated June 10, 2004. The test results indicated that the water contamination of the inboard bearing lube oil sump would not likely have adversely affected the function of the pump during its mission time. The issue was subsequently reevaluated under the guidance of the reactor oversight process on June 30, 2004. It was determined to be an issue of very low risk significance (Green) that was in violation of 10 CFR 50, Appendix B, Criterion XVI, for not correcting the leaking pump packing following identification of packing leaks on November 20, 2002, and again on March 18, 2003. Because of the very low safety significance of this issue and because the issue has been entered into the licensee's corrective action program as PIP O-03-05237, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000269,270, 287/2004003-04, Failure to Promptly Identify and Correct Seal Water Leakage Contamination of the SSF ASW Pump Inboard Bearing Lube Oil Water Contamination.

.13 (Open) URI 05000269,270,287/2004002-04, Potential Failure to Maintain Reactor Building (RB) Coatings per GL 98-04 Commitments, Resulting in Potential Loss of Reactor Building Emergency Sump (RBES) Recirculation. During the Unit 2 outage, the licensee scraped approximately 2300 square feet of delaminated containment coatings from the containment liner (above the 4th floor). These scraped areas were not repainted. In addition, approximately 1600 square feet of delaminated coatings on the containment liner (below the 4th floor) was scraped and recoated. An additional 1200 square feet of delaminated containment coatings above the containment polar crane was left unrepaired. The licensee indicated that repair of this 1200 square feet of delaminated coatings in the overhead was not feasible due insufficient planning time, a lack of specialized equipment to gain access, and concerns over personnel safety.

Subsequently, following the Unit 2 containment integrated leak rate test, the inspectors noted that approximately 250 square feet of additional containment coatings had delaminated. Approximately 50 square feet of this additional delaminated coatings was readily in reach and scraped prior to startup. The licensee contended that their present efforts were consistent with their GL 98-04 response, in that they minimized coatings that may be susceptible to detachment from the substrate during a loss of coolant accident event. Additionally, the licensee indicated that they were evaluating new techniques/equipment that would allow repair of overhead coating degradation in the future. Plans were not yet available for the upcoming Unit 1 and 3 outages; however, the licensee indicated that delaminated coatings would be repaired as necessary.

During a Unit 1 containment entry on June 18, 2004, the licensee noted numerous paint chips on the floor and initiated PIP O-04-04102. The licensee evaluated the paint chips using their current 50% sump blockage requirement that does not require mechanistic evaluation of the blockage (i.e., debris generation, transport, and accumulation modeling), and concluded that the paint would not affect the emergency sump. This issue will remain unresolved pending further inspection to determine: (1) what impact degraded coatings may have had on all three Units' RBES; and (2) if the licensee had taken adequate corrective action to ensure the amount of coatings that may be susceptible to detachment from the RB substrate during a loss of coolant accident event was minimized. The impact determination of the degraded coatings on the RBESs will consider, as appropriate, any guidance for assessing sump performance from the resolution of related Generic Safety Issue (GSI)-191. However, such guidance is currently not expected until Fall 2004.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Dave Baxter, Engineering Manager, and other members of licensee management at the conclusion of the inspection on July 1, 2004. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
N. Alchaar, Civil Engineering
S. Batson, Mechanical/Civil Engineering Manager
D. Baxter, Engineering Manager
R. Brown, Emergency Preparedness Manager
N. Constance, Operations Training Manager
D. Covar, Training Instructor
C. Curry, Maintenance Manager
T. Curtis, Reactor & Electrical Systems Manager
G. Davenport, Compliance Manager
C. Eflin, Requalification Supervisor
P. Fowler, Access Services Manager, Duke Power
T. Gillespie, Operations Manager
R. Griffith, QA Manager
B. Hamilton, Station Manager
R. Hester, Civil Engineer
B. Jones, Training Manager
R. Jones, Site Vice President
T. King, Security Manager
B. Lowrey, Steam Generator Engineer
B. Millsaps, SGT Maintenance Manager
L. Nicholson, Safety Assurance Manager
R. Repko, Superintendent of Operations
R. Sharpe, Lead Licensing Engineer, Steam Generator Replacement
J. Smith, Regulatory Affairs
J. Steeley, Training Supervisor
F. Suchar, QC Supervisor
T. Tucker, NDE Level III Examiner
J. Twiggs, Manager, Radiation Protection
J. Weast, Regulatory Compliance

NRC

R. Haag, Chief of Reactor Projects Branch 1
L. Olshan, Project Manager
L. Plisco, Deputy Regional Administrator

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

050000269/2004003-01	URI	Inadequate Unit 1 Reactor Coolant Pump Seal Modification (Section 1R17.2)
050000287/2004003-02	URI	Inadequate Corrective Action Related to the Improper Use of 10 CFR 50.59 to Change the UFSAR Tornado Missile Design Requirements of the Unit 3 Control Room (Section 4OA2.2b(1))

Opened and Closed

050000269,270,287/2004003-03	NCV	Inadequate QC Inspections of Reactor Building Emergency Sumps (Section 4OA2.2b(2))
050000269,270,287/2004003-04	NCV	Failure to Promptly Identify and Correct Seal Water Leakage Contamination of the SSF ASW Pump Inboard Bearing Lube Oil Water Contamination (Section 4OA5.12)

Previous Items Closed

05000287/2004-01	LER	Unit 3 Trip Due to Foreign Material in Turbine Electro-Hydraulic Control System (Section 4OA3)
2515/154	TI	Spent Fuel Material Control and Accounting at Nuclear Power Plants (Section 4OA5.1)
2515/152	TI	Reactor Pressure Vessel Lower Head Penetration Nozzle Inspection - Unit 2 (Section 4OA5.9)
05000269,270,287/2004009-01	AV	Failure to Promptly Identify and Correct Seal Water Leakage Contamination of the SSF ASW Pump Inboard Bearing Lube Oil Water Contamination (Section 4OA5.12)

Items Discussed

05000287/2002007-02	URI	Unit 3 Control Room Wall Not Designed to Withstand Tornado Loads (Section 4OA2.2b(1))
2515/153	TI	Reactor Containment Sump Blockage Inspection - Unit 2 (Section 4OA5.10)
2515/156	TI	Offsite Power System Operational Readiness (Section 4OA5.11)
05000269,270,287/2004002-04	URI	Potential Failure to Maintain RB Coatings per GL 98-04 Commitments, Resulting in Potential Loss of RBES Recirculation (Section 4OA5.13)

DOCUMENTS REVIEWED

(Section 1R08.2: In-Process ISI)

Containment Coatings Health Report for 2003
NDE Procedure, NDE-35, Liquid Penetrant Examination, Rev. 19
NDE Procedure, NDE-600, Ultrasonic Examination of Similar Metal Welds in Ferritic and Austenitic Piping, Rev. 15
NDE Procedure, NDE-630, Ultrasonic Examination Using Longitudinal Wave and Shear Wave, Straight Beam Techniques, Rev. 2
NDE Procedure, NDE-960, Ultrasonic Examination of High Pressure Injection System Piping Welds and Base Material at Oconee Nuclear Station, Rev. 1
NDE Procedure, NDE-990, Ultrasonic Examination of Ferritic and Austenitic Piping Welds, Rev. 0
PIP O-03-00458, Failure to transmit all NIS-2 forms for U2 refueling outage EOC19 within 60 days due to ANII review and craft discrepancies not resolved
Owners Report for ISI Inspections, Oconee Unit 2, 2002 Refueling Outage EOC19, June 11, 2003
UT Indication Report UT-04-001, Two indications on ten inch stainless steel LPI piping weld 2LP-148-93
UT Indication Report UT-04-007, Indication on ten inch stainless steel LPI piping weld 2LP-148-94
UT Indication Report UT-04-038, LPI Heat Exchanger 2B Head Flange to Shell weld indications
Replacement Steam Generator Pre-Service Inspection Summary Report
Pre-Service Eddy Current Inspection, B&W Report BWC-TR-2003-12, Replacement Steam Generator Serial Number 006K-03, October 31, 2003
Pre-Service Eddy Current Inspection, B&W Report BWC-TR-2003-13, Replacement Steam Generator Serial Number 006K-04, November 7, 2003
Examination Technique Specification Sheet (ETSS) for Bobbin Examination of OTSG tubes, Rev. 1
ETSS for X-Probe Examination of OTSG tubes, Rev. 1
Guidelines for Evaluation of Bobbin Profilometry in the Tubesheet Area for Oconee Nuclear

Power Plant Replacement Steam Generator Tubing, Rev. 0
Pre-service Eddy Current Data Analysis Procedure of Alloy 690 Tubing for Duke Power Oconee ROTSG, Rev. 1

(Section 4OA2.3: Correction of Operator Training Issues)

Nuclear Station Directive (NSD) 203 Operability
NSD 204 Operating Experience Program (OEP) Description
NSD 208 Problem Investigation Process
NSD 210 Corrective Action Program Directive
NSD 212 Cause Analysis
NSD 223 Trending of PIP Data
NSD 602 Employee Concerns
EOP OP-OC-EAP-BO, Blackout, Rev 3
OTG-002, Individual Training/Evaluation Position Verification, Attachment 6.25, Rev 0
OGT-11, Instructor Qualification, Certification & Continuing Training
OTG-015, Management Observation of Operator Training
OMP 1-18, Implementation Standard During Abnormal and Emergency Events, Rev 19.
OMP 1-9, Administrative control of Operations Procedures
SF-010A, Plant Diagnostics
SNO-CB, Crew Briefs
SNO-PWR, Power Control
SNO-LRTC, RCS Temperature Control
SNO-INV, RCS Inventory Control
SAE-L314, Included but not limited to (Failure of ES Channels 7&8 to Auto Actuate).
SAE-L330, Included but not limited to (Failure of ES Channels 5&6 to Auto Actuate).
SAE-L338, Included but not limited to (“A” TBVs Fail Open/1MS-17 (“A” TBV Block) fails to close).
SAE-L334, Included but not limited to (Blackout).
SAE-L226, Included but not limited to (1A TBV Fails Open).
SAE-R052, Requal Exercise Guide
SF-105a, LP1 Cross-Tie Modification
OP-OC-EAP-BO, Blackout Lesson Plan, Rev 3
OP-OC-ADM-EOP, Emergency Operating Procedure, Rev 0
HLP Instructor Training - Pre Job Brief
ADM-OVST, SRO Oversite, Rev 01
PIP O-02-03709, Low Pressure Injection Equipment (Reinsertion of Alternate Boron Dilution)
PIP O-03-04450, Observation and comments made during the 2003-301 NRC Initial License Exam
PIP O-03-06589, HLP Simulator NRC Exam Performance

(Section 4OA5.6: Containment Restoration Activities)

Modification Package ON-23086, Containment Opening, Part AS9, Revision 2, including 10 CFR 50.59 Screening Document
Work Package 23555, Unit 1 Construction Opening Steel Liner Installation
Work Package 23550, Unit 1 Construction Opening Concrete Installation

SGT Certification of Engineering Calculation 0CS-8420, SGRP and RVHRP Code Reconciliation (Other than Reactor Coolant System), Revision 3
Oconee Specification No. OSS-0139.00-00-001, Reactor Building Liner Plate and Accessory Steel, Revision September, 14, 1971
Oconee Specification No. OSS-0139.00-00-004, Specification For Field Welding of Reactor Building Liner Plate By Manual Metal-Arc Process, Revision January 15, 1968
Concrete Reinforcing Bar Splicer Qualification Records for Nine SGT Rebar Splicers
Wiss, Janney, Elstner, Associates, Inc. Letter dated September 15, 2003, documenting static tensile tests qualification of rebar splicing system
SGT Specification SGRP-SPEC-C-04, Reactor Building-SGRP Construction Opening Reinforcing Steel, Revision 3
Procedure BPI-GRIP Systems Splicing Manual and Operating Instructions, Revision 10/18/01
NDE Examiner Qualification Records for the following SGT NDE Examiners: 4 Level II VT and MT Examiners; 1 Level II RT examiner, 1 Level III VT, PT, and MT Examiner; and 1 Level III RT Examiner
NDE Examiner Qualification Records for the Duke Power Level III Examiner
Radiographic Examination Reports and Film for Liner Plate Welds LP-1, LP-2, LP-3, and LP-4
Magnetic Particle Examination Reports for Liner Plate Welds LP-1, LP-2, LP-3, and LP-4, back-gouge and final weld
Certification Records for MT Yokes SGT-0043, SGT-0045 and SGT-0046
Certification Records for MT Powder Lots 03A007 and 02K076
SGT Quality Execution Procedure 12.06, Radiographic Examination (ASME) , Revision 2
SGT Quality Execution Procedure 12.05, Magnetic Particle Examination, Revision 3
SGT Welding Procedure Specification GT-SM/1.1-2, Revision 3
SGT Procedure Qualification Record GT-SM/1.1-Q6
SGT Procedure Qualification Record UE-47, Revision 3
Welder Qualification Records for Chicago Bridge and Iron (CB&I) Welders 004, 005, 006, 008, 009, 010, 011, 012, 015, 018, 019, 020, and 021
Receipt Inspection Reports and Certified Material Test Reports for 3/32" E7018 - Lot 2K129A02, and 1/8" E7018 - Lot 4H30C01 Welding Electrodes
SGT Nonconformance Report (NCR) 02-070 - Existing Damage to Liner Plate After Concrete Removal - Gouges and Broken Liner Plate to Stiffener Welds
SGT NCR 02-071- Liner Plate Gouges Caused by Concrete Removal
Oconee Problem Investigation Process (PIP) O-04-01724 - Unit 2 Reactor Building Liner Plate Stiffener Welds Cracked and Deformation in Liner Plate
SGT NCR 02-019 - Bulges in Containment Liner Plate
Specification No. SGRP-SPEC-C-003, Reactor Building - SGRP Construction Opening and Concrete Placement, Rev. 3, dated 10/28/03, and Variation Notices 23086 AS9-O and 23036 AS9-W
Work Plan 23550, Unit 2 Construction Opening Concrete Installation
Quality Execution Procedure QEP 11.03, Concrete and Grout Placement, Rev. 0E1, dated 9/10/02
Duke Procedure MP/0/A/3005/013, Reactor Building Coating Inspection Procedure
Drawing number SK-23086AS9-003, Rev 2, Containment Opening Unit 2, Construction Opening Details

Drawing number SK-23086AS9-004, Rev 2, Containment Opening Unit 2, Sections and Details
Drawing number SK-23086AS9-008, Rev 2, Containment Opening Unit 2, Notes, References, and Schedules
Results of Unit 2 Containment Structural Inspection completed on 12/9/99 in accordance with Duke Procedure MP/2/A/3005/010, Rev 7
National Ready Mixed Concrete Association (NRMCA) certificate for batch plant, truck mix
National Ready Mixed Concrete Association (NRMCA) certificates for concrete truck mixers, Zupan & Smith concrete truck numbers 63, 64, 70, 72, 74, 75, 84, & 85
Records for calibration of concrete batch plant cement and aggregate scales, and batch plant water meter
Concrete mixer uniformity (ASTM C-94) tests performed on truck numbers 64 & 72
Concrete mix design data
Result of testing performed on concrete materials: Type III cement (ASTM C-150), CTS Komponent admixture, air entraining admixture MB-EA90, lot number 57309Y3, high range water reducer Glenium 3030 NS, lot numbers 57304Y3 and 1347106X3 , fine aggregate (ASTM C-33), number 67 coarse aggregate (ASTM C-33), Ice, and batch plant water
Concrete placement records which included the pre-pour check list, the concrete pour card, concrete batch tickets, and the results of testing performed on the plastic concrete (slump, air content, temperature and unit weight) at the batch plant and point of placement (end of pump line)
SGT Nonconformance Report (NCR) 02-010, Concrete Coverage Over Existing Reinforcing Steel
SGT NCR 02-011, De tensioned Tendons Prior to QC Inspection
SGT NCR 02-019, Containment Liner Plate Bulging in Toward Reactor Building
SGT NCR 02-040, Corrosion on Tendon 34V3
SGT NCR 02-047, Rust on Tendon Wires in Tendons 34V25, 34V28, and 34V29
SGT NCR 02-061, Damage to 9 Horizontal Tendon Sheaths
SGT NCR 02-062, Damage to Tendon Sheathing 42H63 During Hydrolasing
SGT NCR 02-070, Damage to Liner after Concrete Removal
SGT NCR 02-071, Gouges on Containment Liner Plate Caused by Concrete Removal
SGT NCR 02-084, Rebar Damaged (bent) by Hydrolasing Equipment
SGT NCR 02-096, Missing One Vertical Rebar
SGT NCR 02-102, Cement Test Showed Sulfur Tri-Oxide Slightly Exceeded ASTM C-150 Limits
SGT NCR 02-114, Some Concrete Placed in Construction Opening With Slump Slightly Above Specification Requirements and Low Entrained Air Content
PIP O-04-01724, Unit 2 Reactor Building Liner Plate Stiffener welds Cracked and Deformations in Liner Plate
PIP O-02-03173, Reactor Building Coatings Degradation
PIP O-03-04376, Corrective Actions for Bulletin 2003-01, ECCS Sump Blockage
PIP O-04-01826, Excessive Delamination of Reactor Building Coatings on Fourth floor
PIP O-04-02591, Compliance with Generic Letter 98-04
QA Condition 1 Coating Inspection records for inspection dates 11/9/99, 5/1/01 and 10/16/02

(Section 4OA5.7: Review of SGRP Lifting and Transportation)

DPC PIPs: O-04-2069, O-04-2374, O-04-3024, O-04-3525, O-04-3524, O-04-3079, O-04-3782,
SGT Corrective Action Request (CARs): CAR-04-02
SGT NCRs: 02-027, 02-006, 1085, 02-075, 02-046, 02-049, 02-050, 02-051, 02-066, 02-072, 02-073, 02-074, 02-080, 02-086, 02-0
SGT Calculation, OSC-8612, Evaluation of RCS Hot Leg Pipe Deflection due to Rigging Load, Rev. 0 & Rev. 1
Replacement Steam Generator Pre-Service Inspection Summary Report, Attachments BWC-TR-2003-012, BWC-TR-2003-013
DPC Report - Oconee Unit 2 SG Nozzle 2RC-279-90V
Test Procedure: MEI-80255-D10, Outside Lifting Structure, Rev. 1
Test Procedure: MEI-80255-D08, Temporary Lifting Device, Rev. 2
Modification Package ON-23086-AS6, Steam Generator Rigging and Handling, Rev. 2
Modification Package ON-23086 AM1, Main Steam Piping, Rev. 1
Modification Package ON-23086 AM4, Steam Generator Replacement, Rev. 2
Modification Package ON-23086 AM9, Auxilary Crane, Rev. 1
Modification Package ON-23086 AM3, Emergency Feedwater Piping, Rev. 1
Modification Package ON-23086 AM2, Main Feedwater Piping, Rev. 1
DPC Spec. No.: OSS-0210.00-00.0001, SGRP-SPEC-M-002, Reactor Coolant System Hot Leg Elbows, Rev. 3
Work Package 21032, Installation of U2 Outside Lift System (OLS)
Work Package 21035, Installation of U2 Temporary Lifting Device (TLD)
Work Package 23065A, RCS Cold Leg Machining / Welding SG2A

- Welds: 2RC-279-90V & 91V
- Weld Data Cards
- NDE: PT, RT, MT & UT
- Mod Package: ON-23086-AM4
- NCRs: 02-074, 02-086, 02-066
- Drawings
- Material Data Sheets
- Removal and Installation of Supports
- Materials and Parts List
- Piping Installation

Work Package 23085A, Install Main Steam FeedWater - Piping SG2A

- Weld: 2FDW-226-99V
- Weld Data Cards
- NDE: VT-3, RT, MT & UT
- Mod Package: ON-23086-AM2
- Drawings
- Material Data Sheets
- Removal and Installation of Supports
- Materials and Parts List
- Piping Installation

Work Package 23085B, Install Main Steam FeedWater - Piping SG2B

- Welds: 2FDW-253-108V & 109V & 110V &111V
- Weld Data Cards

- NDE: RT, MT & UT
- Mod Package: ON-23086-AM2
- NCRs: 02-080, 02-101, 02-104
- Drawings
- Material Data Sheets
- Removal and Installation of Supports
- Materials and Parts List
- Piping Installation

Work Package 23065B, RCS Cold Leg Machining / Welding SG2B, Rev. 2

- Mod Package: ON-23086-AM4

ASME Section IX Welding Procedure Specification, WPS No.: GT/CLAS 1.3-1, Rev. 3
ASME Section IX Welding Procedure Specification, WPS No.: GT/1.1-1, Rev. 2

RT films reviewed:	2MS-124-69V	SG2A	Main Steam -A side
	2RC-279-90V	SG2A	RCS Cold Leg 2A2
	2FDW-189-30V	SG2	Feedwater
	2RC-279-88V	SG2A	RCS Hot Leg

Taylor Forge Engineering Services Package for RCS Hot Leg 145° Elbow, Items 1F and 1D
Purchase Order, Specifications, CMTR, C of C, NDE reports (MT,PT, RT,UT), PWHT, Hydro testing, Welding and Weld repairs.
DPC Specification No.: OSS-0210.00-00.0001, Specification No.: SGRP-SPEC-M-002, Rev. 3, Reactor Coolant System Hot Leg Elbows
QEP 12.06, Radiographic Examination, Rev. 2
QEP 12.16, Ultrasonic Examination of Ferritic Piping Welds (ASME Section XI), Rev. 0
QEP 20.01, Control and Documentation of Welding, Rev. 3
QEP 20.03, ASME General Welding Requirements, Rev. 3
QEP 20.05, Welding Material Control, Rev. 4E1
QEP 20.07, Weld and Base Metal Repairs, Rev. 0E1
SGRP and RVHRP Code Reconciliation (Other than Reactor Coolant System), 5/30/03
SGRP and RVHRP Code Reconciliation (Reactor Coolant System), 4/7/03

LIST OF ACRONYMS

ADAMS	-	Agency wide Documents Access and Management System
AP	-	Abnormal Procedure
ASME	-	American Society of Mechanical Engineers
ASTM	-	American Society for Testing and Materials
ASW	-	Auxiliary Service Water
BMV	-	Bare Metal Visual
CAP	-	Corrective Action Program
CCW	-	Condenser Circulating Water
CFR	-	Code of Federal Regulations
DEC	-	Duke Energy Corporation
ECCS	-	Emergency Core Cooling
EDG	-	Emergency Diesel Generator
FDW	-	Feedwater
FME	-	Foreign Material Exclusion

GPM	-	Gallons per Minute
HPI	-	High Pressure Injection
HPSW	-	High Pressure Service Water
ICS	-	Integrated Control
IP	-	Inspection Procedure
IR	-	Inspection Report
ISI	-	Inservice Inspection
IST	-	Inservice Testing
KHU	-	Keowee Hydro Unit
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
LPI	-	Low Pressure Injection
LPSW	-	Low Pressure Service Water
MDEFW	-	Motor Driven Emergency Feedwater
MS	-	Main Steam
MT	-	Magnetic Particle
NCV	-	Non-Cited Violation
NDE	-	Non-Destructive Examination
NRC	-	Nuclear Regulatory Commission
NRMCA	-	National Ready Mixed Concrete Association
NRR	-	Nuclear Reactor Regulation
ONS	-	Oconee Nuclear Station
OOS	-	Out of Service
OTSG	-	Once-Through Steam Generator
PARS	-	Publicly Available Records
PIP	-	Problem Investigation Process report
PM	-	Preventive Maintenance
PMT	-	Post-Maintenance Testing
PT	-	Liquid Penetrant
PWHT	-	Post Weld Heat Treatment
QC	-	Quality Control
RBES	-	Reactor Building Emergency Sump
RBS	-	Reactor Building Spray
RCMUP	-	Reactor Coolant Makeup Pump
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RFO	-	Refueling Outage
RP	-	Radiation Protection
RPV	-	Reactor Pressure Vessel
RTP	-	Rated Thermal Power
RV	-	Reactor Vessel
SDP	-	Significance Determination Process
SGRP	-	Steam Generator Replacement Project
SSC	-	Structure, System and Component
SSF	-	Standby Shutdown Facility
TDEFW	-	Turbine Driven Emergency Feedwater
TI	-	Temporary Instruction

TS	-	Technical Specification
U1	-	Unit 1
U2	-	Unit 2
U3	-	Unit 3
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
UT	-	Ultra Sonic
WO	-	Work Order