UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 27, 2005

EA-04-136
EA-04-137

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 - INTEGRATED INSPECTION REPORT 05000269/2004005, 05000270/2004005, 05000287/2004005

Dear Mr. Jones:

On December 31, 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 January 06, 2005, with Mr. Ron Jones 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.

Based on the results of this inspection, there were three findings (one NRC identified and two self-revealing) of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as non-cited violations (NCVs), in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, one licensee-identified violation, which was determined to be of very low safety significance (Green), is listed in Section 4OA7 of this report. 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 addition, based on a review of Licensee Event Reports and a followup inspection, the inspectors determined that small amounts of pressure boundary leakage from reactor vessel head penetrations occurred on several occasions prior to reactor head replacements, due to primary water stress corrosion cracking. Because Technical Specifications (TS) require that with any reactor coolant pressure boundary leakage, the plant be placed in hot standby within 12 hours, the NRC concluded that violations of TS occurred. The violations involved reactor coolant system pressure boundary leakage not avoidable by the reasonable quality assurance measures and management controls that were employed by you. Although these issues constitute violations of NRC requirements, we have concluded that Duke Energy Corporation's actions did not contribute to the degraded conditions and, thus, no performance deficiencies were identified. Based on these facts, I have been authorized, after consultation with the, Director, Office of Enforcement, to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and refrain from issuing enforcement action for the violations. An evaluation was performed and we have determined that there were three instances of substantial safety significance, and one was an instance of very low safety significance. Leakage through these penetrations had the potential to cause circumferential cracks, which could have grown large enough to initiate a loss of coolant accident. The reactor heads at all three Oconee units have been replaced with new heads constructed of material that is less susceptible to this problem. This generic problem is the subject of NRC Bulletins 2001-01, 2002-01, and 2002-02, and NRC Order EA 03-009 and its first revision. NRC actions to generically address this problem, have resulted in new requirements for licensees to effectively examine these penetrations for flaws on a periodic basis.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and any response 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 by Victor M. McCree for/

William D. Travers
Regional Administrator

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

Enclosure: NRC Integrated Inspection Report 05000269/2004005, 05000270/2004005, 05000287/2004005

cc w/encl: See page 3

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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:	50-269/2004005, 50-270/2004005, 50-287/2004005
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	September 26 - December 31, 2004
Inspectors:	M. Shannon, Senior Resident Inspector A. Hutto, Resident Inspector E. Riggs, Resident Inspector B. Crowley, Senior Reactor Inspector (Section 4OA5.6) J. Fuller, Reactor Inspector (Sections 1R08 and 4OA5.7) W. Loo, Senior Health Physicist (Sections 2OS1 and 2OS2) P. Van Doorn, Senior Reactor Inspector (Sections 4OA2.3, 4OA3.3, 4OA3.4, 4OA3.5, and 4OA3.6) R. Cortes, Reactor Inspector (Sections 4OA3.3, 4OA3.4, 4OA3.5, and 4OA3.6) R. Chou, Reactor Inspector (Sections 4OA5.9 and 4OA5.10)
Approved by:	M. Ernstes, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

.
IR 05000269/2004005, IR 05000270/2004005, IR 05000287/2004005; 09/26/2004 - 12/31/2004; Oconee Nuclear Station, Units 1, 2, and 3; Event Followup and Other Activities.

The report covered a three-month period of inspection by the onsite resident inspectors and announced region-based inspections by: two senior reactor inspectors, three reactor inspectors, and one senior health physicist. Three 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: Barrier Integrity

- Green. A self-revealing non-cited violation of Technical Specification 5.4.1, Procedures, was identified for an inadequate Unit 3 spent fuel pool (SFP) makeup procedure, which resulted in the inadvertent draining of approximately 10,000 gallons of spent fuel pool inventory to the unit's borated water storage tank (BWST) and the declaration of a Notice of Unusual Event (NOUE).

  The finding was considered to be more than minor, because if left uncorrected, the inadvertent drain down of the SFP could have rendered the SFP cooling pumps inoperable. However, the inadvertent transfer of water from the SFP would have ceased when the suction of the SFP cooling pumps was uncovered, leaving approximately 20 feet of water over the top of the SFP racks to provide sufficient cooling to and shielding of the irradiated fuel assemblies in the Unit 3 SFP. Consequently, the finding was of very low safety significance. (Section 4OA3.1)

Cornerstone: Mitigating Systems

- Green. A self-revealing non-cited violation of 10 CFR 50, Appendix B, Criterion XI, Test Control, was identified for the failure to establish and perform adequate testing to ensure that the standby shutdown facility (SSF) submersible pump would operate correctly to provide SSF equipment with a makeup source of water to the Unit 2 condenser circulating water (CCW) header when called upon. Specifically, the licensee's test program had failed to reveal that the pump's power leads had been reversed since November 19, 1992, despite the performance of twelve surveillances between November 19, 1992, and February 3, 2004.

  Failure to maintain the SSF submersible pump in a ready to operate condition was considered to be more than minor, in that, its incorrectly wired motor leads directly affected the cornerstone objective to ensure equipment reliability of a mitigating system (i.e., the SSF). A Phase 3 risk analysis determined that this issue was of very low risk significance. This was based primarily on the availability of an alternate source of water inventory to fill the Unit 2 CCW header (i.e.,via reverse, gravity supplied CCW flow from Lake Keowee through the unit's condensate coolers). (Section 4OA5.8)

Cornerstone: Initiating Events

- Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, for the failure to maintain design clearances on Unit 2 feedwater piping whip restraints. Specifically, the inspectors identified that clearances between the Unit 2 feedwater pipe whip restraint nuts and structural mounting plates were not in accordance with (i.e., significantly less than) the gap requirements specified in the associated design drawing; thereby, creating additional piping stresses while at normal operating conditions.

  This finding was greater than minor because it is associated with the configuration control attribute and affected the objective of the Initiating Events Cornerstone to limit the likelihood of events that challenge critical safety functions. In addition, if left uncorrected, this finding could have become a more significant safety concern, in that continued increased stresses on the feedwater piping and the uncertainties in the analyses could have resulted in a piping failure. The finding was evaluated using the Reactor Safety SDP and determined to be of very low safety significance because the inspectors determined that the licensee's conclusion, that the pipe would not have failed at the time of discovery, was reasonable. (Section 4OA5.11)

B. Licensee-Identified Violations

One violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation is listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status:

Unit 1 entered the report period at 100 percent rated thermal power (RTP). The unit was reduced to approximately 88 percent RTP on November 28, 2004, to perform turbine valve movement testing. The unit was returned to 100 percent RTP on the same day, where it remained through the end of the inspection period.

Unit 2 entered the report period at 100 percent RTP. The unit was reduced to approximately 88 percent RTP on November 28, 2004, to perform turbine valve movement testing. The unit was returned to 100 percent RTP on the same day, where it remained through the end of the inspection period.

Unit 3 entered the report period at 100 percent RTP. On October 2, 2004, a reduction in reactor coolant system (RCS) average temperature (Tave) was commenced in advance of the Unit 3 end-of-cycle 21 (3EOC21) refueling outage. The unit was shutdown from approximately 98 percent RTP on October 9, 2004. On October 19, 2004, with the unit's core offload completed, a notification of unusual event (NOUE) was declared due to an uncontrolled water level decrease in the Unit 3 SFP. The cause of the level decrease was quickly identified to be the interaction of two evolutions being performed simultaneously on the unit's spent fuel system. The appropriate valve lineups were secured, and the SFP water level stabilized with approximately 23 feet of water remaining over the top of the fuel racks. The SFP water level was subsequently raised 1.28 feet; thereby, returning the SFP water level to the high side of its normal operating band. On December 31, 2004, the unit entered Mode 1 (Operation) and achieved approximately 6 percent RTP prior to returning to Mode 3 (Hot Standby) to investigate problems with the unit's Core Thermal Power Demand (CTPD) portion of the Integrated Control System (ICS).

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed the licensee's preparations for the onset of seasonal cold weather. Specifically, the inspectors reviewed the completed maintenance work orders for checks of freeze protection circuits for the Unit 1, 2 and 3 borated water storage tanks and the associated level instrumentation. The inspectors determined whether the freeze protection circuit checks were performed before any significant cold weather impacted the plant. The inspectors reviewed the data from IP/0/B/1606/009, Preventive Maintenance and Operational Check of Freeze Protection, and IP/0/B/0203/001A, Low Pressure Injection System Borated Storage Water Tank Level Instrument Calibration, to verify the applicable circuits met acceptance criteria. The inspectors also determined whether the elevated water storage tank level instrumentation line blown downs were initiated and scheduled to be performed every two weeks during the cold weather months per work order 98657024 01.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

As listed below, the inspectors conducted three partial equipment alignment walkdowns this inspection period 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.

- 2B low pressure injection (LPI) train with the 2A LPI train out of service (OOS) for scheduled maintenance

- The Unit 1 and 2 shared low pressure service water (LPSW) system, trains A and B, with the C LPSW pump OOS due to emergent work involving replacement of the motor because of bearing damage - Problem Investigation Process report (PIP) O-04-8497

- Keowee Hydroelectric Unit (KHU) 1 with KHU 2 and the associated underground path inoperable due to failure of the closing coil on the excitation breaker - PIP O-04-8584

b. Findings

No findings of significance were identified.

.2 Complete Walkdown of the Unit 2 Emergency Feedwater (EFW) System

a. Inspection Scope

The inspectors performed a system walkdown on accessible portions of the Unit 2 EFW system. The inspectors focused on verifying proper valve positioning, power availability, adequate lubrication in oil reservoirs, no obstacles existed to equipment cooling, adequate area ventilation, no damage to structural supports, support systems were properly aligned and functional, and acceptable material condition. Documents and drawings reviewed for this semi-annual inspection sample are listed in the Attachment to this report.

A review of PIPs and maintenance work orders was performed to verify that material condition deficiencies did not significantly affect the ability of the EFW system to perform its design functions and that appropriate corrective action was being taken by the licensee.

The inspectors also held discussions with the system and design engineers on temporary modifications, future modifications, and operator workarounds to ensure that the impact on the equipment functionality was properly evaluated.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours in the twelve areas of the plant listed below, in order 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.

- standby shutdown facility (SSF) pump room, diesel room, ventilation room, and control room (4)
- radioactive waste building (1)
- Units 1, 2, and 3 spent fuel pool heat exchanger and pump rooms (2)
- Units 1, 2, and 3 component cooling heat exchanger and pump rooms (2)
- Units 1, 2, and 3 LPI heat exchanger rooms (3)

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

a. Inspection Scope

ISI Activities

The inspectors reviewed results for ISI examinations completed this outage, reviewed ISI procedures, and reviewed selected ISI records since the last outage, associated with risk significant structures, systems, and components. This was the second outage of the third period of the third ten-year interval. The inspection activities, documentation, and supporting records were compared to the requirements specified in the Technical Specifications (TS) and the ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, with no addenda, to verify compliance and to ensure that examination results were appropriately evaluated and dispositioned.

Specifically, non-destructive examination (NDE) activities were reviewed as follows:

Direct Observation

Remote ultrasonic examination (UT): 3-PDA-2-8 (B09.011.020), Reactor Vessel Inlet Nozzle to Pipe Weld at 210E
Remote UT: 3-PHA-1 (B09.011.001), Reactor Vessel Outlet Nozzle to Pipe at 270E

Record Review

UT: B05.130.003A/3-PHB-17, Pressurizer Surge Nozzle to Safe End Buttering
UT: B05.130.012/3-PSL-10, Pipe to Nozzle (Surge Nozzle on B Hot Leg)
UT: B03.110.009/3-PZR-WP26-1, Nozzle to Shell
radiographic examination (RT): LP-4 R2, Liner Plate Butt Weld Repair, Shot 8-9

The inspectors reviewed the following recordable indications to ensure that they were dispositioned in accordance with ASME Code requirements:

liquid penetrant examination (PT): 3-PZR-WP91-1, Nozzle to Safe End
UT: C05.021.005, 3-51A-118-1, Pipe to Elbow
UT: B05.130.012A/3-PSL-10, Pipe to Nozzle (Surge Nozzle on B Hot Leg)
UT: C05.051.003/3MS-117-23, Pipe to Elbow
PT: B09.011.023A, 3-PDB2-1, Pump to Pipe
PT: C05.011.005A, 3-53A-17-17, Valve to Pipe
RT: 3-RC-0211-70, 3A1 HPI Nozzle Thermal Sleeve Replacement
RT: LP-4 T1/T2, Liner Plate Butt Weld, Shot 8-9

Qualification and certification records for examiners, inspection equipment, and consumables along with the applicable NDE procedures for the above ISI examination activities were reviewed. In addition, samples of ISI issues in the licensee's corrective action program were reviewed for adequacy. Specific documents reviewed are listed in the Attachment to this report.

The inspectors reviewed the "Oconee Nuclear Station Unit 3 EOC 20 Refueling Outage Inservice Inspection Report," dated September 11, 2003, documenting one reportable item, which was found during a VT-3 examination of hanger 3-04A-SR3. The inspectors reviewed the associated corrective action documentation and engineering evaluation for hanger 3-04A-SR3. The inspectors reviewed the NIS-1 Form (report of inservice inspections), and a sample of the NIS-2 Forms (report of repairs and replacements) for compliance to ASME Code requirements.

The inspectors reviewed weld data sheets, the welding procedure specification, supporting welding procedure qualification records, welder qualification records, and preservice examination results for the following welds to ensure those welding activities were conducted in accordance with ASME Section III and Section IX requirements:

3-LP-0223-28, Pipe to Tee, LPI Passive Cross-Connect Modification, ASME Class 2
3-LP-0223-29, Pipe to Tee, LPI Passive Cross-Connect Modification, ASME Class 2
3-LP-0223-30, Pipe to Tee, LPI Passive Cross-Connect Modification, ASME Class 2
3-RC-0211-70, Nozzle to Pipe, 3A1 High Pressure Injection (HPI) Thermal Sleeve Replacement, ASME Class 1

Boric Acid Corrosion Control (BACC) Inspection

The inspectors reviewed implementation of the licensee's BACC program to determine if commitments made in response to Generic Letter 88-05 and Bulletin 2002-01 were being effectively implemented. The inspectors reviewed the inspection records for a sample of BACC walkdown visual examination activities, to verify that the examiners were adequately identifying and documenting boric acid leakage throughout the plant. The inspectors reviewed the inspection scope of the BACC Program to ensure that it included locations where boric acid could cause degradation to safety-related components. The inspectors also reviewed a sample of engineering evaluations and associated corrective action documents to evaluate the engineering bases for conclusions regarding apparent cause and severity of discovered leaks, and justification for corrective actions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator simulator training on November 10, 2004. The scenario began with the simulated unit operating at 100 percent reactor thermal power. The scenario involved a steam generator tube rupture and a subsequent loss of offsite power. The inspectors observed crew performance in order to assess licensed operator performance and the evaluators' critique, focusing on: communications; ability to take timely and proper actions; prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the abnormal procedures; timely control board operation and manipulation, including immediate operator actions; and oversight and direction provided by the shift supervisor and shift technical advisor, 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 the two items listed below, 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.

- Keowee Hydro Unit failures during this quarter, which included the following PIPs: O-04-7005, KHU-1 lockout during a maintenance run initiated by the exciter generator field ground detector circuitry; O-04-6067, failure of the KHU-1 governor actuator circuitry caused by a failure of the distributing valve feedback signal; O-04-8547, failure of the KHU-1 air brakes; O-04-8543, received exciter warning alarm caused by high field temperature; and O-04-8584, failure of the closing coil for the exciter breaker.

- Turbine Building Flood Detector maintenance, which included the following: IP/0/B/0235/003, Turbine Building Water Level Alarm System Check; EP/1,2,3/A/1800/001H, EOP - Turbine Building Flood; AP/1,2,3/A/1700/010, Turbine Building Flood; Selected Licensee Commitment (SLC) 16.9.11, Turbine Building Flood Protection Measures

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluations

a. Inspection Scope

The inspectors evaluated the following attributes for the seven selected SSCs and activities 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.

- Unit 3 Orange risk condition, Complex Plan for equipment lifts near main steam lines in Mode 3 or greater

- PIP O-04-7143, Annual Fire Suppression Test results in water intrusion into CT-4 control cabinets causing the KHU underground power path, CT-4, to be inoperable and an unplanned Orange risk condition

- Orange risk condition due the Unit 3 Condenser work (turbine building flood concern) with the SSF unavailable

- Deferral of the SSF monthly PMs due to water in the Units 1 & 2 C LPSW pump bearing

- PIP O-04-8497, Unit 1 & 2 C LPSW pump OOS for emergent work in replacing the pump's motor due to bearing damage

- PIP O-04-8560, Unit 2 Engineered Safeguards (ES) Channel C alarmed and placed in tripped condition, requiring emergent work on the RCS Loop B Wide Range Pressure Instrument Wiring

b. <u>Findings</u>

No findings of significance were identified.

1R14 <u>Personnel Performance During Nonroutine Plant Evolutions</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the operating crew's performance during the three non-routine events and/or transient operations listed below, to determine if the response was appropriate to the event. As applicable, the inspectors: (1) reviewed operator logs, plant computer data, or strip charts to determine what occurred and how the operators responded; (2) determined if operator responses were in accordance with the response required by procedures and training; (3) evaluated the occurrence and subsequent personnel response using the SDP; and (4) confirmed that personnel performance deficiencies were captured in the licensee's corrective action program.

- PIP O-04-7007, Declaration of NOUE due to an uncontrolled water level decrease in the Unit 3 SFP

- PIP O-04-8584, failure of closing coil for the KHU-2 exciter breaker and resulting inoperability of the Keowee overhead power path

- PIP O-04-7005 and PIP O-04-7067 related to both KHUs being potentially inoperable at the same time

b. <u>Findings</u>

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

As listed below, the inspectors reviewed six, 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.

- PIP O-04-6189, Failure to meet cable separation requirements, in that, 1LP-19 and 1LP-20 cables were in the same cable tray
- PIP O-04-7005, KHU-1 normal lockout during a maintenance run initiated by the exciter generator field ground detector circuitry
- PIP O-04-6067, Failure of the KHU-1 governor actuator circuitry (emergency lockout) caused by a failure of the distributing valve feedback signal
- PIP O-04-7259, Unit 1 turbine driven emergency feedwater pump operable on main steam only
- PIP O-04-7143, Numerous alarms received during mulsifyre test due to water intrusion into the transformer control cabinets for CT-4
- PIP O-04-8641, Damaged grid straps on fuel assembly NJ12EF

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

.1 Semi-Annual Review of the Cumulative Effects of Workarounds

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 two significant operator work-arounds listed below to determine if the functional capability of the respective systems 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-04-6759, 1HP-15 malfunctioned after the operator interface was replaced. The malfunction of the 1HP-15 controller in automatic caused the control room operators to make RCS inventory additions with 1HP-15 in manual until the operator interface was repaired and tested satisfactorily. During that time, reactivity control was maintained by the use of initial and final bleed holdup tank (BHUT) and let down storage tank (LDST) levels.

- The work-around reviewed was documented in PIP O-04-6871, 2HP-15 failed to reset after makeup. The malfunction of the 2HP-15 controller caused the control room operators to make RCS inventory additions with 2HP-15 in manual until a new Moore controller was installed and tested satisfactorily. During that time, reactivity control was maintained by the use of initial and final BHUT and LDST levels.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT)

a. Inspection Scope

The inspectors reviewed the three PMT procedures and/or test activities listed below, 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.

- PT/2/A/0600/013, 2A Motor Driven Emergency Feedwater (MDEFW) Pump Test, following motor inspection and lubrication

- PT/2/A/0203/006A, 2A LPI Pump Test, following train maintenance

- PT/3/A/0150/003A, Unit 3 Reactor Building Integrated Leak Rate Test, following reactor building construction opening restoration

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 October 9, 2004, and December 31, 2004, the following activities related to the Unit 3 refueling outage were reviewed for conformance to applicable procedures and selected activities associated with each evaluation were witnessed:

- Outage risk management plan/assessment
- Plant cooldown
- Mode changes from Mode 1 (power operation) to No Mode (defueled)
- Shutdown decay heat removal and inventory control
- Clearance activities
- Reactor coolant system instrumentation
- Containment closure
- Refueling activities
- Mode changes from No Mode (defueled) to Mode 1 (power operation)
- Plant heatup
- Core physics testing

In addition, the inspectors reviewed the problem identification and resolution aspects with respect to the stuck fuel assembly that occurred during core reload (PIP O-04-8561). The inspectors reviewed the refueling procedure modifications implemented to free the assembly with reactor engineering personnel and observed the performance of a portion these procedures. The inspectors also observed the in-vessel inspections of the affected fuel assemblies.

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 seven 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/3/A/0251/001, Low Pressure Service Water Pump Test (Inservice testing (IST))
- PT/3/A/0204/007, 3B Reactor Building Spray Pump Test (IST)
- PT/0/A/0400/005, SSF Auxiliary Service Water Pump Test (IST)
- PT/0/A/0251/010, Station Auxiliary Service Water Pump Test (IST)
- CP/1,2/A/2002/001, Units 1 and 2 RCS Sampling Systems
- PT/1/A/0600/010, Unit 1 RCS Leak Rate Test
- PT/3/A/0151/019, Unit 3 Penetration 19 Leak Rate Test (Containment Leak Rate)

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications

a. Inspection Scope

The inspectors reviewed documents and drawings, as well as observed portions of the implementation of three temporary modifications listed below. The inspectors observed, as appropriate: that the installations were consistent with the modification documents and were in accordance with the configuration control process; that adequate procedural changes were made; and that post installation tests were adequate.

- OE-18746 related to the installation of a temporary piping support for the high pressure service water (HPSW) system in the auxiliary building, which was installed for the subsequent replacement of degraded piping

- Work Order (WO) 98697190, Unit 2 stator coolant high temperature runback initiation coincidence changed to 2 out of 2 by removing the failed temperature circuit from the original 2 out of 3 coincidence

- ONTM-2180, Operator Aid Computer Temporary Power (3TDC1), installed to support OAC power supply replacement

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

Simulator Based Evolution

a. Inspection Scope

The inspectors observed and evaluated a simulator based emergency preparedness drill held on November 10, 2004. The drill scenario involved a spill of a toxic substance (Hydroxine) which created the possibility of a toxic gas release. This required the operators to identify that the event caused the plant to be in an “Unusual Event” condition. The operators successfully determined the proper classification of the event and simulated making the appropriate notifications of the counties, state, and NRC.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control To Radiologically Significant Areas

a. Inspection Scope

Access Control

The inspectors evaluated the licensee’s activities for monitoring and controlling worker access to radiologically significant areas during the Unit 3 refueling outage (RFO) and steam generator replacement (SGR) activities, as well as select activities associated with the previous Unit 2 RFO and SGR not reviewed during the previous NRC inspection. The inspection included direct observation of administrative and physical controls, appraisal of the knowledge and proficiency of radiation workers and health physics technicians (HPTs) in implementing radiological controls, and review of the adequacy of procedural guidance and its implementation.

The inspectors observed implementation of radiological controls for selected Unit 1, Unit 2, and Unit 3 Radiation Areas (RA), Radioactive Material Areas, and High Radiation Areas (HRA) within Radiologically Controlled Area (RCA) locations. Posting and labeling of materials at these locations were evaluated for consistency with the licensee's procedural guidance and compliance with NRC regulatory requirements. The inspectors directly observed the posting and locking status of the only Very High Radiation Area (VHRA) in Unit 3 containment at the time of the onsite inspection and selected HRAs and Extra High Radiation Areas (EHRAs) in Unit 1, Unit 2, and Unit 3 Auxiliary Buildings. Independent dose-rate measurements were taken in the Unit 3 Reactor Building and the results of those measurements were compared to current licensee surveys. In addition, the inspectors toured and reviewed radiological controls for the Steam Generator Retirement Facility, which was located outside the plant's Protected Area but within the owner-controlled area. The inspectors evaluated the use of radiological controls, observed the performance of HPTs and radiation workers, evaluated Radiation Work Permit (RWP) requirements and electronic dosimeter alarm setpoints, and discussed various task evolutions with selected personnel associated with SGR activities. During general observations of Unit 3 RFO work, the inspectors discussed with select radiation workers, RWP requirements associated with their tasks in progress.

The inspectors reviewed administrative guidance documents and procedures for control of radioactive material stored in the spent fuel pools, postings and surveys of various plant areas, access controls to EHRAs, and RWP use. The inspectors reviewed selected RWPs and surveys of related areas to evaluate the adequacy of radiological controls for RAs, HRAs, and airborne areas. Discussions with licensee personnel indicated there had been no internal doses exceeding 50 mrem committed effective dose equivalent in the past year. Health Physics (HP) supervisory personnel, including the Radiation Protection (RP) Manager, were interviewed regarding the administrative control of EHRA and VHRA keys, as well as any changes to procedural guidance for access control. RP program activities and their implementation were evaluated against 10 CFR 19.12; 10 CFR Part 20, Subparts B, C, F, G, H, I, and J; UFSAR Section 12.4, RP Program; and licensee commitments and approved procedures. Licensee procedures, records, and other documents reviewed within this inspection area are listed in the Attachment to this report.

<u>Problem Identification and Resolution</u>

Issues identified through department self-assessments, Functional Area Evaluation audits, and PIPs associated with radiological controls, personnel monitoring, and exposure assessments were reviewed and discussed with cognizant licensee representatives. The inspectors assessed the licensee's ability to characterize, prioritize, and resolve the identified issues in accordance with Duke Power Quality Assurance Program Related, Nuclear Policy Manual, Nuclear System Directive: 208, Problem Investigation Process. This included trends observed by the licensee in areas such as an increase of the loss of thermoluminescent dosimeters (TLD) and electronic dosimeters during 1EOC21, individuals placing their TLDs in the security x-ray machine, personnel contamination events, and entry by individuals on the wrong RWP. Specific assessments, audits, and PIPs reviewed and evaluated in detail for this inspection area are identified in the Attachment to this report.

b. Findings

No findings of significance were identified.

2OS2 As Low As Reasonably Achievable (ALARA) Planning and Controls

a. Inspection Scope

ALARA Planning and Controls

The inspectors evaluated the licensee's ALARA program guidance and its implementation for ongoing job tasks during the Unit 3 RFO, including those activities associated with the SGR. The inspectors reviewed and discussed with licensee staff, ALARA planning, dose estimates, and prescribed ALARA controls for selected outage work activities expected to incur significant collective doses. Those activities included radiography testing, installation and removal of scaffolding, RCS pipe cutting, removal and installation of RCS temporary and permanent supports, and removal of the old steam generators. Also reviewed was the implementation of dose-reduction initiatives for high person-rem-expenditure tasks. These elements of the ALARA program were evaluated for consistency with the methods and practices delineated in applicable licensee procedures.

The implementation and effectiveness of ALARA planning and program initiatives during work in progress were evaluated. Projected dose expenditure estimates detailed in current ALARA planning documents were compared to actual dose expenditures, and noted differences were discussed with cognizant ALARA staff. Changes to dose budgets relative to changes in job scope also were discussed. The licensee had originally established an ALARA goal of 134.9 rem; however, early in the outage, the licensee overestimated their dose and established a new challenge ALARA goal of 103.5 rem. At the time of the onsite inspection with approximately two weeks left in the outage, the dose was at 103.8 rem. The licensee did not anticipate much more dose due to the few outage activities left scheduled.

Implementation and effectiveness of selected program initiatives with respect to source-term reduction were evaluated. Dose rate trending data was reviewed and discussed with the ALARA Coordinator. The inspectors reviewed the licensee's process for generating and evaluating shielding requests. The effectiveness of selected shielding packages installed for the current outage was assessed from a review of survey records, as well as direct observations made by the inspectors during tours of the licensee's facilities.

ALARA program activities and their implementation were evaluated against 10 CFR 19.12; 10 CFR Part 20, Subparts B, C, F, G, and J; and approved licensee procedures. In addition, licensee performance was evaluated against Regulatory Guide (RG) 8.8, Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations will be As Low As Reasonably Achievable.

Problem Identification and Resolution.

Licensee PIP documents associated with ALARA planning and controls were reviewed and discussed with responsible licensee representatives. The inspectors assessed the licensee's ability to identify, characterize, prioritize, and resolve the identified issues in accordance with licensee procedures. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstones

a. Inspection Scope

The inspectors sampled licensee submittals for the performance indicators (PIs) listed below for the period from October 2003 through September 2004. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02 and Regulatory Assessment Performance Indicator Guideline, Revision 2, were used to verify the basis in reporting for each data element.

Mitigating Systems Cornerstone

- Safety System Unavailability for the Residual Heat Removal System (all units)
- Safety System Unavailability for the Heat Removal System - [Emergency Feedwater] (all units)
- Safety System Unavailability for the High Pressure Injection System (all units)
- Safety System Unavailability for the Emergency AC Power System (Keowee with each unit's individual power path)

The inspectors reviewed a selection of Licensee Event Reports (LERs), portions of Unit operator log entries, Technical Specification Action Item Log (TSAIL) entries, PIP description entries, monthly operating reports, and PI data sheets to verify that the licensee had adequately identified the number of unavailability hours. These numbers were compared to the numbers reported for the PIs.

b. Findings

No findings of significance were identified.

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 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 June 2004 through December 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
- 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

No findings of significance were identified.

.3 Annual Sample Review

a. Inspection Scope

The inspectors selected PIP O-04-00518 for review, which involved the licensee's evaluation for Violation (VIO) 269,270,287/2004007-01, Failure to Obtain Prior NRC Approval to a Change to the Facility Involving Unreviewed Safety Questions on High Energy Line Break Analysis. The PIP was reviewed to verify that the licensee had performed an adequate root cause evaluation and initiated appropriate corrective actions. The inspectors evaluated the root cause evaluation and proposed corrective actions, as well as held discussions with licensee personnel regarding the results of a recent 10 CFR 50.59 self-assessment.

b. Findings

No findings of significance were identified. The inspectors determined that the licensee had performed a thorough root cause and self-assessment with appropriate proposed corrective actions. However, the corrective action plan had not yet been approved and most of the corrective actions were yet to be completed. Therefore, this PIP, as well as the associated violation and corrective actions, will be reviewed further at a later date.

4OA3 Event Followup

.1 Recent Events

a. Inspection Scope

The inspectors evaluated the event listed below to assess the overall impact on the plant and mitigating actions. As appropriate, the inspectors: (1) observed plant parameters and status, including mitigating systems/trains; (2) determined alarms/conditions preceding or indicating the event; (3) evaluated performance of mitigating systems and licensee actions; and (4) confirmed that the licensee properly classified the event in accordance with emergency action level procedures and made timely notifications to NRC and state/county governments as required.

- PIP O-04-7007, Declaration of NOUE due to an uncontrolled water level decrease in the Unit 3 SFP

f. Findings

Introduction: A Green non-cited violation (NCV) was identified for an inadequate SFP makeup procedure, in that, the procedure failed to prohibit the control room operators from adding makeup water to the Unit 3 SFP while aligned to pump down the Unit 3 fuel transfer canal (FTC) deep end. Consequently, on October 19, 2004, the use of OP/3/A/1104/006C, SFP Makeup, contributed to the creation of a flowpath from the Unit 3 SFP to the Unit 3 BWST, which resulted in the transfer of approximately 10,000 gallons of water from the Unit 3 SFP to the Unit 3 BWST with the SFP cooling pumps.

Description: On October 19, 2004, with the Unit 3 core offload completed and the FTC deep end aligned to be pumped down to the Unit 3 BWST, an addition of makeup water from the 3A bleed holdup tank (BHUT) to the unit's SFP was planned, as SFP level was low in the operating band of +0.3 to +0.6 feet (i.e., 23.99 feet to 24.29 feet above the top of the fuel racks). At approximately 9:10 p.m., 3SF-49 (the Unit 3 SFP filter outlet header block valve) was opened and the 3A bleed transfer pump was started to commence makeup to the Unit 3 SFP per OP/3/A/1104/006C. The control room operating crew immediately noted that 3A BHUT level was decreasing as expected; but, that the Unit 3 SFP level was unexpectedly decreasing. Consequently, AP/3/A/1700/035, Loss of SFP Cooling and/or Level Abnormal Operating procedure, was entered. At 9:58 p.m., the Unit 3 BWST high level alarm was received in the Unit 3 Control Room. At 10:10 p.m., a NOUE was declared due to an uncontrolled level decrease in the Unit 3 SFP with all of the irradiated fuel assemblies remaining covered with water. At 10:15 p.m., the Unit 3 SFP level stabilized at -0.68 feet (i.e., 23.01 feet above the top of the fuel racks) following the closure of 3SF-47 (the Unit 3 BWST Filter Outlet Valve). 3SF-47 had been opened on October 18, 2004, to pump down the Unit 3 FTC deep end per OP/3/A/1102/015, Filling and Draining FTC. At 10:23 p.m., the licensee determined that the conditions for a NOUE no longer existed, and the declaration was terminated. At 11:03 p.m., an NRC event notification was made.

An investigation concluded that the lack of procedural guidance prohibiting the control room operators from attempting to add makeup water to the Unit 3 SFP while aligned to pump down the unit's FTC deep end to the BWST with the borated water recirc pump was a root cause in this event. Specifically, OP/3/A/1104/006C failed to prohibit the control room operators from establishing a flow path from the SFP cooling pumps to the BWST by opening 3SF-49 to add makeup water to the Unit 3 SFP while 3SF-47 was open to pump down the FTC deep end.

Analysis: The finding was considered to be greater than minor because if left uncorrected, the inadvertent drain down of the SFP could have rendered the SFP cooling pumps inoperable. However, the inadvertent transfer of water from the SFP would have ceased when the suction of the SFP cooling pumps was uncovered, leaving approximately 20 feet of water over the top of the SFP racks to provide sufficient cooling to and shielding of the irradiated fuel assemblies in the SFP. Consequently, the finding screened out of the SDP Phase 1 analysis as very low safety significance (Green).

Enforcement: TS 5.4.1 requires that written procedures shall be established, implemented, and maintained covering activities related to procedures recommended in Regulatory Guide 1.33 Rev. 2, Appendix A, 1978. Regulatory Guide 1.33, Section 3(h), Procedures for Startup, Operation and Shutdown of Safety-Related PWR Systems, requires procedures for energizing, filling, venting, draining, startup, shutdown, and changing modes of operation for the Fuel Storage Pool Purification and Cooling System. Contrary to the above, OP/3/A/1104/006C failed to prohibit the addition of makeup water to the Unit 3 SFP while pumping down the Unit 3 FTC deep end, resulting in approximately 10,000 gallons of water being transferred from the Unit 3 SFP to the Unit 3 BWST. Because this violation is of the low safety significance and has been entered into the licensee's corrective action program as PIP O-04-7007, it is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000287/2004005-01, Inadequate SFP Makeup Procedure Results in the Inadvertent Draining of

Approximately 10,000 Gallons of Water from the Unit 3 SFP and the Declaration of a NOUE.

.2 (Closed) LER 05000269/2002-04-00, Potential Loss of Safety Function Due to Inadequate Design Documentation and Procedure Change

The licensee submitted this LER on September 9, 2002, as a result of a potential to damage the low pressure injection system during post loss of coolant accident (LOCA) recirculation due to a procedure change of the emergency operating procedures. The licensee determined through subsequent reviews and analysis that the plant conditions required to cause the damage (pressure/temperature) were incompatible with the entry conditions in the procedure that directed the system lineup that would allow the damage (alternate boron dilution). As a result, the licensee withdrew the LER in correspondence dated October 14, 2003. The inspectors reviewed the licensee's assessment and basis for withdrawing the LER, and determined that the withdrawal was appropriate. This LER is closed.

.3 (Closed) LER 05000287/2001-03-00, Minor Reactor Pressure Vessel Head Leakage From Several Control Rod Drive Nozzle (CRDM) Penetrations Due to Primary Water Stress Corrosion Cracking

In November 2001, five CRDM nozzle penetrations on Oconee Unit 3 were found leaking. This was the second occurrence on Unit 3 where penetration leakage was discovered. CRDM Nozzle #2 had three axial through-wall cracks and a 48 degree circumferential crack (0.18" depth; not through-wall; outer diameter (OD) initiated). The licensee previously examined the Oconee 3 reactor vessel nozzles in February 2001 by visual method and identified nozzles with circumferential cracking. The licensee performed an extent of condition review at that time (ultrasonic examination (UT) of the original nine nozzles with visible leakage and an additional 9 nozzles). Nozzle #2 was not selected for examination at that time with UT.

Circumferential cracking of CRDM nozzles from the OD is a result of Primary Water Stress Corrosion Cracking from active leakage of reactor coolant and wetting via a pre-existing through-wall crack in the nozzle or penetration weld. Exposure times on the order of years is necessary for a circumferential crack to develop and grow to a length of concern. Since nozzle #2 was found with a circumferential crack in November 2001, with less than 7 months of operating time, it is evident that nozzle #2 was actively leaking at least as far back as February 2001. An inspection was therefore conducted on October 19-20, 2004, to determine if leakage associated with nozzle #2 was the result of a licensee performance deficiency.

The inspectors reviewed docketed correspondence and licensee information associated with the nozzle # 2 leak. This included records for the Unit 3 reactor vessel head inspections of February, 2001 and November, 2001; pictures of head conditions from February, 2001; informal documentation of licensee activities; Root Cause analyses; PIPs; Unit 3 Head Timeline for 1988 thru 2003; industry inspection guidance; a CRDM housing crack fracture mechanics analysis; and nozzle # 2 UT results from November 2001. In addition, the inspectors held discussions with five personnel directly involved with the Unit 3 nozzle leak.

The inspectors determined that during the Unit 3 forced outage the licensee conducted voluntary visual inspections and found leaks on February 18, 2001. The licensee's examiner identified six initial leaks and following head cleaning, residual boron was noted in the annulus area and three more leaks were identified. During this time frame, there was limited industry experience as to how leakage would appear. Voluntary visual inspections were performed, without extensive guidance, by one licensee engineer with no independent verification. The industry knowledge base was essentially being developed by this person. The engineer's expectation, based on his personal experience, was that leakage would be obvious with significant amounts of fresh boron with popcorn-like texture noted. Masking with residual boron, such as from previous CRDM flange leaks, was not thought to inhibit the detectability of leaks at that time.

Pictures of the head revealed significant staining and residual boron from previous flange leaks; no pictures were taken of nozzle #2. This nozzle was near the top of the head near insulation and not easily viewed. The licensee's examiner stated that about 180 degrees around the nozzle was visually inspected. The licensee's examiner indicated that, at that time, he was confident nozzle #2 did not show leakage, based on his expectation of what leakage would look like.

Extent of condition review by the licensee (NDE sampling of nine additional nozzles) was based on heat number (all but one nozzle was the same heat as the leakers), location on the head (no clear pattern was observed), and drives that had been removed for access. These criteria were consistent with previous experience on Unit 1. No additional indications were found, which appeared to validate the licensee's belief that leaks could be effectively identified via visual examinations.

During the planned November 2001 Unit 3 outage, the licensee discovered additional nozzles of concern; four listed as "obvious" leakers and three as "suspicious," including nozzle # 2. Five nozzles were ultimately confirmed to be leaking. Nozzle #2 was confirmed as having through-wall defects via NDE with one indication conservatively noted as circumferential. The NDE methods for detection, characterization, and sizing of defects were still considered developmental and have continued to evolve. The nozzle #2 circumferential crack was only seen by the 60 degree shear wave transducer and had no tip diffraction signal (used for more accurate sizing). The circumferential crack was evaluated as extending for 48 degrees of the circumference at 0.18" deep maximum. The licensee's analysis conservatively showed that it would take 4.83 years to structural failure, if one assumed a 180 degree through-wall crack.

The inspectors concluded that at that time, the licensee's decisions for inspection/repair of Unit 3 head CRDM nozzles were reasonable. The violation was not avoidable by these particular quality assurance measures and management controls, which were considered reasonable at the time, and no performance deficiency was identified.

The inspectors did not identify a performance deficiency associated with the other nozzles that were reported to have been leaking. It is unknown as to when these nozzles started leaking. The inspectors did not identify any evidence to conclude that the nozzles had been leaking prior to the February 2001 outage. The inspectors considered that the licensee had complied with the ASME B&PV code requirements and that corrective actions were reasonable at that particular time, given the level of industry knowledge of the phenomena. Corrective actions have included replacement of all three reactor heads at Oconee with ones constructed of material less susceptible to primary water stress corrosion cracking.

The leaking nozzles were assessed for risk by the NRC. The assessment considered the fact that the nozzles had not previously been examined by UT technique to eliminate the possibility of circumferential cracking, which would reduce the risk. The assessment model used later industry experience and considered the likelihood of through-wall leaks developing, circumferential cracks developing, and crack growth rates leading to catastrophic failure. The model includes adjustments for specific parameters of leaking nozzles, such as angle on the head, head temperature, plant age, and nozzle heat number. The associated risk of operating with vulnerable nozzles can be reduced by performing the necessary non-destructive examinations and eliminating the possibility that circumferential cracking has initiated. The probability of CRDM nozzle ejection, which causes a medium size LOCA, is applied to the licensee's SPAR model. The assessment determined this issue to have resulted in a risk of substantial safety significance.

Pressure boundary leakage was a violation of requirements, in that, Technical Specification Limiting Condition for Operation 3.4.13(a) limits operational leakage to "No pressure boundary leakage" while in Modes 1-4. However, as discussed in the NRC's Enforcement Policy, the NRC may refrain from issuing enforcement action for violations resulting from matters not within the licensee's control, such as equipment failures that were not avoidable by reasonable licensee quality assurance measures or management controls. Based on the circumstances of these violations, the NRC considers it appropriate to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and refrain from issuing enforcement action for this violation.

.4 (Closed) LER 05000269/2002-03-00, Minor Reactor Pressure Vessel Head Leakage Due to Primary Water Stress Corrosion Cracking of An Alloy 600 Control Rod Drive Nozzle

(Closed) Unresolved Item (URI) 05000269/200202-03, Reactor Pressure Boundary Leakage During Operation

In March 2002, the licensee conducted its second examination of the Unit 1 CRDM nozzles for leakage and identified one nozzle (#7) with an axial through-wall leak in the J-groove weld. The licensee concluded that there was strong evidence that nozzle 7 was leaking through the weld and that the leak initiated during the past operating cycle. Technical Specification Limiting Condition for Operation 3.4.13(a) limits operational leakage to "No pressure boundary leakage" while in Modes 1-4. The licensee's corrective actions included repairs to the nozzle, future inspections in accordance with commitments made in response to NRC Bulletin 2001-01, and elimination of alloy 600 material by replacement of the reactor head. No performance deficiency was identified. This issue was evaluated for risk by the NRC, which considered the fact that this nozzle had not previously been examined by UT technique to eliminate the possibility of circumferential cracking. The evaluation determined this to have resulted in a risk of substantial safety significance. However, as discussed in the NRC's Enforcement Policy, the NRC may refrain from issuing enforcement action for violations resulting from matters not within the licensee's control, such as equipment failures that were not avoidable by reasonable licensee quality assurance measures or management controls. Based on the circumstances of these violations, the NRC considers it appropriate to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and refrain from issuing enforcement action for this violation.

.5 (Closed) LER 05000269/2003-02-00, Apparent Reactor Coolant System Leakage From Three Reactor Vessel Head Penetrations

In September 2003, the licensee replaced the Unit 1 reactor head. The licensee visually observed 2 CRDM nozzles (#s 6 and 16) and 1 thermocouple nozzle on the old head that exhibited leakage characteristics. Technical Specification Limiting Condition for Operation 3.4.13(a) limits operational leakage to "No pressure boundary leakage" while in Modes 1-4. The licensee's corrective actions were to replace the reactor head. No performance deficiency was identified. This issue was evaluated for risk by the NRC, which considered the fact that the CRDM nozzles had not previously been examined by UT technique to eliminate the possibility of circumferential cracking. The evaluation determined this to have resulted in a risk of substantial safety significance. However, as discussed in the NRC's Enforcement Policy, the NRC may refrain from issuing enforcement action for violations resulting from matters not within the licensee's control, such as equipment failures that were not avoidable by reasonable licensee quality assurance measures or management controls. Based on the circumstances of these violations, the NRC considers it appropriate to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and refrain from issuing enforcement action for this violation.

.6 (Closed) LER 05000287/2003-01-00, Apparent Reactor Coolant System Leakage From A Reactor Vessel Head Nozzle

In April 2003, the licensee replaced the Unit 3 reactor head. The licensee visually observed that #4 CRDM nozzle on the old head exhibited leakage characteristics. Technical Specification Limiting Condition for Operation 3.4.13(a) limits operational leakage to "No pressure boundary leakage" while in Modes 1-4. The licensee's corrective actions were to replace the reactor head. No performance deficiency was identified. This issue was evaluated for risk by the NRC, which considered the fact that this nozzle had been examined by UT during the previous outage to eliminate the possibility of circumferential cracking at that time. Since the leak was found after the nozzle had been previously inspected and found to be clear of circumferential cracks, there was insufficient time between the two examinations for a circumferential crack to initiate and grow large enough to eject the nozzle. Thus, the associated risk from the leak was limited to very small level by the licensee's actions. The evaluation determined this to have resulted in a risk of very low safety significance. However, as discussed in the NRC's Enforcement Policy, the NRC may refrain from issuing enforcement action for violations resulting from matters not within the licensee's control, such as equipment failures that were not avoidable by reasonable licensee quality assurance measures or management controls. Based on the circumstances of these violations, the NRC considers it appropriate to exercise enforcement discretion in accordance with Section VII.B.6 of the Enforcement Policy and refrain from issuing enforcement action for this violation.

4OA5 Other Activities

.1 Unit 3 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
02.03.e.3.	Implementation of foreign material exclusion controls	4OA5.2
02.03.e.2.	Implementation of radiation protection controls	4OA5.2
02.04.1	Containment testing	1R19
02.03.d	Restoration of temporary containment opening	4OA5.6
02.03.a	Welding, nondestructive examination	4OA5.9 & .10
02.04.7	Preservice inspection of welds	4OA5.9 & .10

.2 SGRP Foreign Material Exclusion (FME) Controls, Radiation Protection (RP) 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 FME 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 RP personnel were assigned to provide RP job coverage.

b. Findings

No findings of significance were identified.

.3 (Closed) Unit 3 Reactor Pressure Vessel Lower Head Penetration Nozzle Inspection

a. Inspection Scope (TI 2515/152)

The inspectors reviewed activities associated with the inspection of the Unit 3 reactor vessel (RV) lower head penetrations in response to NRC Bulletin 2003-02. The guidelines for the inspection are provided in NRC temporary instruction (TI) procedure 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 3
- Critical Evolution Plan, Unit 3 EOC 21 Under Vessel Inspection
- WO# 98661145, Unit 3 Inspect Reactor Vessel Lower Head for Bare Metal
- Oconee Training Records, Incore Nozzle Bare Metal Inspection Course
- Video documentation of BMV exam of Unit 3 Reactor Vessel Lower Head
- PIP O-03-3504, Corrective Action # 7, Results of Unit 3 reactor vessel lower head bare metal inspection

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 and previous inspections of the lower head penetrations of Units 1 and 2. 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 3.

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 3 lower head penetrations exists.

.4 (Closed) Unit 3 Reactor Containment Sump Blockage Inspection

I. Inspection Scope (TI 2515/153)

The inspectors reviewed activities associated with the inspection of the Unit 3 Reactor Building Emergency Sump (RBES) blockage concerns in response to NRC Bulletin 2003-01. The guidelines for the inspection were provided in NRC temporary instruction (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 Unit 3 RFO.

Specifically, the inspectors reviewed and observed:

- The licensee's response to NRC Bulletin 2003-01, dated August 7, 2003
- IP O-03-3618, QC requirements required by MP/0/A/1800/105 "Reactor Building Emergency Sump" not met during initial performance
- PIP O-03-4376, which tracked Bulletin 2003-01 and the associated corrective actions
- PIP O-03-7864, Discrepancies in configuration of [Unit 1] RBES
- PIP O-04-1495, Minor discrepancies in [Unit 2] RBES screen fitup
- PIP O-04-4770, NRC Exit Report 2004-03 has identified a trend associated with inadequate QA/QC inspections
- PIP O-04-6800, Unit 3 Reactor Building Emergency Sump configuration discrepancies discovered during system walkdown, including gaps and breeches
- WO# 98697897, Repairs to Unit 3 RBES to correct deficiencies documented in PIP O-04-6800
- MP/0/A/3005/012A, Containment Pre-Inspection Clean Out Procedure
- MP/0/A/3005/012, Containment Inspection/Close Out Procedure
- MP/0/B/3005/013, Reactor Building Coating Inspection Procedure
- MP/0/A/1800/105, Enclosure 13.6, Final Sump Cover Installation and Screen Inspection
- NSD 104 Material Condition/Housekeeping, Cleanliness/Foreign Material

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

The following interim compensatory measure was reviewed during this inspection period. All other interim compensatory measures were reviewed by the inspectors during the 1EOC21 RFO and the 2EOC20 RFO, and are documented in Inspection Report 05000269,270,287/2003005 and 05000269,270,287/2004003, respectively.

6. ensuring sump screens are free of adverse gaps and breaches

   The licensee's response to NRC Bulletin 2003-01 noted that RBES inspections are performed every refueling outage and consist of three different, independent inspections. However, as described below, during the 3 EOC 20, 1 EOC 21, 2 EOC 20 and 3 EOC 21 RFOs, adverse gaps and breeches were discovered and repaired on all three Oconee Unit's RBESs.

   NRC inspection report 05000269,270,287/2004003, dated July 23, 2004, documents the licensee's receipt of a Green NCV for failing to perform adequate Quality Control (QC) inspections of all three Oconee Unit's RBESs, in that, gaps and breaches, which may have existed for the entire lives of the plants, were not discovered during previous QC inspections. This violation was documented as NCV 05000269,270,287/2004003-03, Inadequate QC Inspections of Reactor Building Emergency Sumps.

   The increased scrutiny placed on RBES inspections resulted in the discovery of additional adverse gaps and breaches in the Unit 3 RBES on October 14, 2004 (3 EOC 21 RFO). PIP O-04-6800 documents the discovery of the adverse gaps and breaches, as well as a past operability assessment, which concludes that the Unit 3 RBES was Operable but Degraded/Nonconforming. The adverse gaps and breaches in the Unit 3 RBES have been repaired, and the RBES was inspected satisfactorily by licensee QC personnel prior to the unit entering Mode 4 (Hot Shutdown) on December 24, 2004.

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

Walkdowns of the Unit 3 RB were completed by contractor representatives and the licensee on October 12, 2004. The walkdown was conducted to assess the construction and layout of an Oconee unit's RB, the size and layout of an Oconee unit's RBES, the as-found condition of an Oconee unit's RB prior to the commencement of RFO activities, and the potential debris sources located within an Oconee unit's RB.

The licensee and contractor personnel utilized the guidance contained within NEI 02-01, "Condition Assessment Guidelines: Debris Sources Inside PWR Containments" to conduct this walkdown. The licensee expects to receive the contractor's walkdown report/analysis in mid-January 2005. The licensee intends to utilize the contractor's report/analysis as an input into the planned modifications of the Unit 1, 2 and 3 RBESs, as described in TI 2515/153-05e.

b. Findings

TI2515/153-05 Reporting Requirements

a. A walkdown of the Unit 3 containment was conducted during the 3 EOC 20 and 3 EOC 21 RFOs by the licensee to quantify potential debris sources.

b. Not applicable

c. Not applicable

d. A walkdown did check for gaps in the Unit 3's RBES screens, and plant design prohibits major obstructions in the flow paths to the sumps. As stated in 2515/153 (03.02), adverse gaps and breaches have been discovered in the Unit 3 RBES during the past two Unit 3 RFOs, 3 EOC 20 and 3 EOC 21.

e. There are preparations being made to make modifications to Units 1, 2 and 3 RBESs, beginning with the Unit 2 RBES during the Fall 2005 RFO, 2 EOC 21.

.5 World Association of Nuclear Operators (WANO) Report Review

The inspectors reviewed the final report issued by WANO on September 24, 2004 for the evaluation that was conducted at the Oconee facility during the period of July 19 through July 30, 2004. The inspectors did not identify any safety issues in the WANO report that either warranted further NRC followup or that had not already been addressed by the NRC.

.6 Unit 3 Containment Restoration Activities

a. Inspection Scope

The inspectors examined restoration activities associated with the temporary construction opening (approximately 22 feet by 25 feet) in the Unit 3 containment, as detailed in the licensee's Modification Package ON-33086, Part AS9, Containment Opening, Revision 1.

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, the 1965 Edition and 1998 Edition with the 1998 Addenda; and Section XI, 1989 Edition with no Addenda, 1992 Edition with the 1992 Addenda, and the 1995 Edition with the 1996 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, including weld material control; visually inspected the final weld surfaces; reviewed the magnetic particle (MT) and visual (VT) inspection reports for the final weld surfaces; and reviewed the final RT film, including reject 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 Weld Data Cards; review of QC involvement in the welding process; and review of QC and 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, Part IV-B, Building Code Requirements for Reinforced Concrete Institute, 1963 and 1999 Editions; AWS D1.4-98, Structural Welding Code-Reinforcing Steel; and ASME Section III, Division 2, 1992 Edition with the 1992 Addenda and the 1995 Edition with the 1995 Addenda). The inspection included review of the rebar splice specification, review of the rebar splice procedure and observation of a sample of approximately 40 re-bars which had the Barsplice swaged couplers mechanically spliced to one end of the bars. In addition, the inspectors reviewed the splice system qualification data, the qualification records for ten splicers, and the tensile test results for 6 sister splices.

The inspectors also reviewed Modification Package ON-33086, Part AS9, Containment Opening, Revision 1, to verify that the modification was properly evaluated in accordance with 10 CFR 50.59. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.7 (Closed) TI 2515/160, Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) - (Unit 3)

The inspectors reviewed the licensee's 60-day response to NRC Bulletin 2004-01, dated June 27, 2004. The inspectors verified that the licensee inspected the following welds in accordance with the commitments made in their response to BL 2004-01.

3-PZR-WP-91-1
3-PZR-WP-91-2
3-PZR-WP-91-3
3-PZR-WP-63-1 through -7
3-RC-243-5
3-50-27-1, 3A, 5, 7, 9, 11
3-PZR-WP45
3-PSP-1
3-50-34-17
3-RC-RD-0043

The inspectors reviewed the BMV examination documentation for the above welds. The inspectors verified that the visual inspections were conducted by personnel qualified to ASME Section XI, VT-2. The inspectors also reviewed the licensee qualified procedure used for the BMV examination to ensure that it contained specific instructions related to the identification, disposition, and resolution of deficiencies.

The inspectors performed an independent walk-down of the top of the pressurizer to ensure that the physical conditions of the pressurizer nozzle to safe end connections were clean and accessible for the prescribed inspections, and that there were no problems with debris, insulation, dirt, boron from other sources, physical layout, or

viewing obstructions which could have interfered with the identification of relevant indications.

<u>The inspectors noted that</u>:

- The visual inspections were by direct visual examination.

- Examiners were able to examine 360E around the circumference of all the nozzles.

- Lighting and access was such that small boron deposits, as described in the Bulletin 2004-01, could have been identified and characterized.

- There were no material deficiencies (i.e., cracks, corrosion, etc.) identified that required repair.

- Other than the expected nozzle-to-safe-end geometry, there were no impediments to effective examinations.

- The VT-2 BMV examinations did not result in any indications. The inspectors reviewed the examination documentation to verify compliance to BL 2004-01.

.8 <u>(Closed) URI 05000269,270,287/2004002-02</u>, Incorrect Wiring of the SSF Submersible Pump's Motor Leads

This issue, which was discussed in detail in Inspection Report 05000269,270,287/ 2004002, was left unresolved pending a Phase 3 risk evaluation. Subsequently, a regional Senior Reactor Analyst performed a Phase 3 risk evaluation of the issue and determined it to be of very low risk significance (Green). This was based primarily on the availability of an alternate source of inventory to fill the Unit 2 condenser circulating water (CCW) header (i.e., via reverse, gravity supplied CCW flow from Lake Keowee through the unit 's condensate coolers). The issue was identified in Inspection Report 05000269,270,287/2004002 as a violation of 10 CFR 50, Appendix B, Criterion XI, for the licensee' s failure to establish and perform adequate testing to ensure that the SSF submersible pump would operate correctly to provide SSF equipment with a makeup source of water to the Unit 2 CCW header when called upon. Specifically, the licensee's test program had failed to reveal that the pump's power leads had been reversed since November 19, 1992, despite the performance of twelve surveillances between November 19, 1992, and February 3, 2004. 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-04-0564, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000269,270,287/ 2004005-02, Incorrect Wiring of the SSF Submersible Pump's Motor Leads.

.9 Welding, Nondestructive Examinations (NDE), and Pre-service Inspections (PSI)

a. Inspection Scope

The inspectors reviewed portions of the fit up, welding, preheat, and post-weld heat treatment (PWHT) activities related to the SGR activities involving portions of RCS, main steam system (MS) and feedwater system (FDW) 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 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 Welding Procedure Specifications (WPS) and Procedure Qualification Records (PQR) used for the welding performed on the RCS, FDW, and MS piping.

Nondestructive examinations reviewed include UT, PT, MT, and RT. The inspectors reviewed NDE documentation to verify that the welds were free of rejectable indications or were repaired based on the approved procedures. The inspectors reviewed 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 testings of UT, PT, MT, and RT were also used for the pre-service inspection requirements.

The inspectors reviewed Work Packages, in process or completed, which included records of change notice, work instructions, NDE calibrations, weld, and weld repaired data cards, preheat and postweld heat treatment records, temporary attachments, Test Reports UT, PT, VT, MT, and RT, consumables certifications, and drawings. The inspectors reviewed NDE examiner certification and visual acuity documentation. For the RT exams the inspectors reviewed films 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 records for the SG eddy current inspection to determine if pre-service and baseline eddy current examinations were performed in compliance with NRC Regulatory Guide 1.83, Duke Power 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-2004-05, Revision 0 and BWC-TR-2004-06, Revision 0 reports. The inspectors reviewed aspects of the examination program for the B&W Once-Through Steam Generators, which included use of bobbin coil and X-probe simultaneously on 100 percent of the tubes from tube-end to tube-end. The inspectors reviewed for wall loss indications in both generators. The inspectors reviewed examples of PIPs and Nonconformance Reports (NCRs) to assess whether the licensee performed adequate evaluations and dispositions. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.10 Review of Pipe Supports Related to Steam Generator Replacement (Units 2 and 3)

a. Inspection Scope

The inspectors reviewed removal and reinstallation of pipe supports related to the SGR in order to assess its adequacy. The procedure used by Steam Generator Team (SGT) QC inspectors was QEP 12.03, Rev. 5E2/AFU, for modified or new supports and QEP 12.12, Rev. 0/AFU, ASME Section XI Visual Examination (VT-1 and VT-3) for existing supports. The inspectors reviewed PIP O-04-06744, Hanger and Support Deficiency Identified During the Implementation of the Steam Generator Replacement Project for 3EOC21 for the Unit 3. The inspectors reviewed 25 NCRs in order to evaluate the adequacy of dispositions, which included oversized anchor bolt holes, spring can cold settings out of tolerances, gaps out of tolerances, and washers installed incorrectly.

The inspectors also reviewed PIPs O-04-01572, -02566, and -03519 for Unit 2. The inspectors reviewed 28 NCRs which included 21 existing and 7 new supports. The inspectors discussed the NCRs and PIPs with the licensee's SGT engineers, SGT QC inspectors, and Duke Plant QC inspectors. The documents reviewed during this inspection are listed in the Attachment to this report.

The inspectors independently selected and walked down portions of nine supports with the licensee engineer to verify the adequacy of the inspection and installation. The nine supports were : 3-04A-2478E-H6686, Rev. 0; 3-48-2478A-H6668, Rev. 1; 3-50-2480B-H6683, Rev. 2; 3-57-2481B-H6672, Rev. 2; 3-57-2481B-H6673, Rev. 3; 3-57-2481C-H6643, Rev. 0; 3-64-2479A-H6700, Rev. A; 3-64-2479D-H6607, Rev. 0 and -H6683, Rev. 0.

b. Findings

No findings of significance were identified.

.11 (Closed) URI 50-270/2002-05-05, Determination of Consequences for not Maintaining Design Clearances on Feedwater Piping Whip Restraints and Corresponding Risk

The performance deficiency associated with this URI was discussed in detail in Inspection Report 05000269,270,289/2002005 and was characterized as being contrary to the requirements of 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures and Drawings. The inspectors reviewed the associated licensee calculation for a mis-configured feedwater whip restraint (i.e., lack of hot gap between nuts and mounting plates during the operation), discussed the calculation and problems with the licensee's engineer and the licensing personnel, and walked down the restraint during cold and hot conditions. The calculation reviewed was Oconee Calculation OSC-8370, Analysis of

Main Feedwater Rupture Restraints with Bounded Rods, Revision 1, for all three units. The purpose of the review was to determine whether or not the calculation was adequate to conclude that the feedwater pipe would not have failed with the mis-configured whip restraint.

This pipe was originally classified by Duke as Class F and reclassified as ASME Class 2 for Inservice Inspection (ISI) purpose. Therefore, the record of code for this pipe was USAS B31.1, Power Piping, 1967 edition. Based on the calculation, the licensee concluded that the pipe would not meet the B31.1 code allowable stresses and NRC MEB 3-1 requirements when the additional stress due to the bounded rods, thermal stresses, and postulated seismic event were added. The pipe would have been overstressed by 62 percent.

The licensee considered that the B31.1 code allowable stresses are based upon 7000 fatigue cycles. The licensee used conservatism built into the Markl curve (or equation) and a factor of safety of 2, to determine that 2268 cycles would have been required for failure. The licensee determined a cumulative fatigue usage factor (0.16) for the life of the plant based on 360 thermal cycles. The licensee also used the same curve to calculate the actual fatigue usage factor (.07) by using the actual number of plant thermal cycles (150). The licensee concluded that the fatigue usage factors for the pipe were less than 1.0 and acceptable. Therefore, although the pipe would not meet the B31.1 stress requirements, the licensee concluded that the pipe would not fail using the conservatism in the Markl curve and the calculated fatigue usage factors.

The licensee also performed an ASME fatigue analysis in order to evaluate the pipe based on Class 1 piping criteria. The result showed that the maximum stress ratio, the actual stress divided by the allowable stress, was .97 which was below the allowable ratio 1.0. The total cumulative fatigue usage factor was .92 for the life of the plant (if the deficient condition was not corrected) which was also below the allowable ratio 1.0. The licensee concluded that the pipe would not fail since the pipe met the ASME fatigue analysis limits.

The calculation assumed surface contact without a hot gap between the nuts and attached bracket plates for the rods, but did not assume the nuts were torqued. The licensee encountered difficulty loosening the nuts. The inspectors questioned why the licensee did not assume the nuts were torqued. The licensee's justification was that the lab report indicated that the rod threads were corroded, which could explain the difficulty in loosening the nuts.

The inspectors noted that the calculation did not consider thermal expansion coefficients for quenched hardened properties of the rods. The licensee stated that the B31.1 code does not provide any requirements to consider the material's quenched hardened properties and only considers chrome (Cr) content for the different thermal expansion coefficients. The licensee used low chrome content for the thermal expansion coefficients. Based on the inspector's observation, the licensee revised the modulus of elasticity by using carbon content greater than .3 percent.

The inspectors questioned the temperatures, thermal expansion coefficients, and moduli of elasticity used for the rods and/or pipe for relative movement between 70 degrees F to 450 degrees F. The licensee had used parameters associated with thermal expansion from 200 degrees F to 450 degrees F. The licensee revised the calculation in revision 2 based on the inspector's comments and included a pipe length reduction of 3.5 inches measured in the field. The total applied stresses between the pipe and rods in revision 2 were slightly less than those calculated in revision 1, as the increase in the thermal stress was reduced by the shorter pipe length.

The inspectors consulted with the NRR Mechanical and Civil Engineering Branch regarding the licensee's conclusions, the use of the Markl curve, and the ASME analysis. The NRR expert indicated that it was reasonable to use the Markl curve as a basis to determine the fatigue usage factor and higher allowable stress as a result of having an actual lower number of cycles than the 7000 cycles assumed in the B31.1 code. The expert indicated that it was appropriate to conclude that the pipe would not fail since the fatigue usage factor was less than 1.0. The expert also indicated that the use of the ASME analysis to evaluate past operability, (though not to qualify the current or future designs), is reasonable, even though the materials were procured and examinations were performed under the B31.1 code. This is because fatigue tests and resultant fatigue curves are based on the material properties only. The stresses due to fatigue are limiting and if the fatigue is evaluated as acceptable, it can be concluded that the pipe would not fail.

This finding was determined to be greater than minor because it is associated with the configuration control attribute and affected the objective of the Initiating Events Cornerstone to limit the likelihood of events that challenge critical safety functions. In addition, if left uncorrected, this finding could become a more significant safety concern in that continued increased stresses on the feedwater piping and the uncertainties in the analyses, could result in a piping failure. The finding was evaluated using the Reactor Safety SDP and determined to be of very low safety significance (Green) because the inspectors determined that the licensee's conclusion, that the pipe would not have failed at the time of discovery, was reasonable. Based on the very low safety significance and because the issue was entered into the licensee's corrective action program as PIP O-02-6240, this violation of 10 CFR 50 Appendix B, Criterion V is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000270/2004005-03, Failure to Maintain Design Clearances on Feedwater Piping Whip Restraints. Accordingly, URI 50-270/2002-05-05 is closed.

4OA6 Management Meetings (Including Exit Meeting)

Exit Meeting Summary

The inspectors presented the inspection results to Mr. R. Jones, Site Vice President, and other members of licensee management at the conclusion of the inspection on January 6, 2005. Subsequently, Mr. M. Ernstes of the NRC Region II Office presented the additional inspection results addressed in Sections 4OA5.8 and 4OA5.11 during a telephone conference on January 27, 2005, with Mr. G. Davenport, Oconee Compliance Manager. 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.

4OA7 Licensee Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being disposition as a NCV.

- TS 3.9.3 requires in part that each penetration providing direct access from the containment atmosphere to the outside atmosphere either be closed by a manual, non-automatic power operated or automatic isolation valve, blind flange or equivalent during the movement of irradiated fuel assemblies within containment. On December 12, 2004, the licensee unexpectedly discovered during performance of the containment closure seven day re-verification, that five Unit 3 main steam drain valves were open. These valves were opened on December 7, 2004, to support drawing initial vacuum on the Unit 3 condenser. On December 14, 2004, the licensee's followup investigation determined that a feedwater drain valve inside the reactor building had also been open; thereby, providing a direct path to the outside atmosphere (via the associated steam generator and the open main steam valves) contrary to TS 3.9.3, as refueling had been on-going during this period. This issue was determined to be of very low safety significance based on the screening criteria found in MC 0609, Appendix H, Containment Integrity Significance Determination Process, approach for assessing Type B findings at shutdown. The issue was screened as having very low safety significance (Green) as the refueling cavity water level remained above the level required by TS for fuel movement and the deficiency did not affect the likelihood of core damage. This issue was documented in the licensee's corrective action program as PIP O-04-8658.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

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T. Cherry, ALARA Supervisor, Radiation Protection (RP)
N. Constance, Operations Training Manager
T. Coleman, ISI Coordinator
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W. Crosby, NDE Level III Examiner, SGT
C. Curry, Maintenance Manager
T. Curtis, Reactor & Electrical Systems Manager
G. Davenport, Compliance Manager
C. Eflin, Requalification Supervisor
W. Elliott, Radiation Protection Manager, SGT
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T. Grant, Engineering Supervisor, Reactor & Electrical Systems
R. Griffith, QA Manager
B. Hamilton, Station Manager
R. Hester, Civil Engineer
D. Jacobs, Project Welding Engineer, SGT
B. Jones, Training Manager
R. Jones, Site Vice President
T. King, Security Manager
T. Ledford, Engineering Supervisor, Reactor & Electrical Systems
B. Lowrey, Steam Generator Engineer
T. McDaniel, Civil/Structural Oversight Engineer
B. Millsaps, SGT Maintenance Manager
R. Murphy, Engineering Support
S. Neuman, Regulatory Compliance Group
L. Nicholson, Safety Assurance Manager
A. Pallon, QC Supervisor, SGT
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W. Pursley, Supervising Scientist, Technical Support, RP
R. Repko, Superintendent of Operations
D. Robinson, General Supervisor, Surveillance and Control, RP
J. Rowell, Engineer, Reactor & Electrical Systems
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J. Smith, Regulatory Affairs
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NRC
M. Ernstes, Chief of Reactor Projects Branch 1
R. Haag, Chief of Plant Support Branch 1
L. Olshan, Project Manager, NRR
L. Plisco, Deputy Regional Administrator, RII
L. Wert, Deputy Division Director, RII

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000287/2004005-01	NCV	Inadequate SFP Makeup Procedure Results in the Inadvertent Draining of Approximately 10,000 Gallons of Water from the Unit 3 SFP and the Declaration of a NOUE (Section 4OA3.1)
05000269,270,287/2004005-02	NCV	Incorrect Wiring of the SSF Submersible Pump Motor Leads (Section 4OA5.8)
05000270/2004005-03	NCV	Failure to Maintain Design Clearances on Feedwater Piping Whip Restraints (Section 4OA5.11)

Previous Items Closed

05000269/2002-04-00	LER	Potential Loss of Safety Function Due to Inadequate Design Documentation and Procedure Change (Section 4OA3.2)
05000287/2001-03-00	LER	Minor Reactor Pressure Vessel Head Leakage From Several Control Rod Drive Nozzle Penetrations Due to Primary Water Stress Corrosion Cracking (Section 4OA3.3)

05000269/200202-03	URI	Reactor Pressure Boundary Leakage During Operation (Section 4OA3.4)
05000269/2002-03-00	LER	Minor Reactor Pressure Vessel Head Leakage Due to Primary Water Stress Corrosion Cracking of An Alloy 600 Control Rod Drive Nozzle (Section 4OA3.4)
05000269/2003-02-00	LER	Apparent Reactor Coolant System Leakage From Three Reactor Vessel Head Penetrations (Section 4OA3.5)
05000287/2003-01-00	LER	Apparent Reactor Coolant System Leakage From A Reactor Vessel Head Nozzle (Section 4OA3.6)
2515/152	TI	Reactor Vessel Lower Head Penetration Nozzle Inspection - Unit 3 (Section 4OA5.3)
2515/153	TI	Reactor Containment Sump Blockage Inspection - Unit 3 (Section 4OA5.4)
2515/160	TI	Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) - Unit 3 (Section 4OA5.7)
05000269,270,287/2004002-02	URI	Incorrect Wiring of the SSF Submersible Pump's Motor Leads (Section 4OA5.8)
05000270/2002005-05	URI	Determination of Consequences for not Maintaining Design Clearances on Feedwater Piping Whip Restraints and Corresponding Risk (Section 4OA5.11)

<u>Items Discussed</u>

05000269,270,287/2004007-01	VIO	Failure to Obtain Prior NRC Approval to a Change to the Facility Involving Unreviewed Safety Questions on High Energy Line Break Analysis (Section 4OA2.3)

DOCUMENTS REVIEWED

Section 1RO4: Equipment Alignment

OP/2/A/1106/06, Emergency Feedwater
EP/2/A/1800/001 Rule 3, Loss of Main or Emergency Feedwater

Enclosure 5.9 of EP/2/A/1800/001, Extended Emergency Feedwater (EFW) Operation
Enclosure 5.26 of EP/2/A/1800/001, Manual Start of Turbine Driven EFW Pump
Enclosure 5.27 of EP/2/A/1800/001, Alternate Methods for Controlling EFW Flow
TS 3.3.14, 3.7.5, and 3.7.6
UFSAR Sections 10.4.7.1, 10.4.7.2, 10.4.7.3, 10.4.7.4, and 10.4.7.5
Selected Licensee Comments 16.7.3, 16.10.3, 16.10.6, and 16.10.7
Drawings OFD 121A-2.8 and OFD 121D-2.1

Section 1R08: ISI Activities

NDE 12, General Radiography Procedure For Preservice and Inservice Inspection, Rev. 11
QAL-15, Inservice Inspection (ISI) Visual Examination, VT-2, Pressure Test, Rev. 21
ESD Boric Acid Corrosion Control Program, Rev. 1
Nuclear System Directive 413, Fluid Leak Management Program, Rev. 3
Oconee Unit 3 Nuclear Power Plant, Year 2004 10 Year Reactor Vessel Examination Program Plan (Scan Plan), Rev 0
Welding Procedure Specification (WPS), GTSM0808-01
PIP S/N: O-04-06591, Mode 3 Tour (Initial Entry for Outage)
PIP S/N: O-04-06596, Engineering Mode 3 Shutdown Tour
PIP S/N: O-03-03996, Results of 6-17-03 RB Tour
PIP S/N: O-04-00246, Findings of Unit 2 quarterly power entry
PIP S/N: O-04-03805, Mode 3 Reactor Building Walkdown
PIP S/N: O-04-07815, I.D. Surface Indication on the HPI Thermal Sleeve Nozzle
PIP S/N: O-03-01519, Recordable Indications on hanger 3-04A-SR3

2OS1 Access Control To Radiologically Significant Areas

Procedures, Manuals, and Guidance Documents

Duke Power Company (DPC), Oconee Nuclear Station, Radiation Protection Routines, Procedure No. HP/0/B/1000/054, Rev. 38
DPC, Industrial Radiography Safety Manual, Procedures for Establishing and Posting Radiation Areas for Radiography and Radioactive Material Storage Areas II-3, Rev. 7
DPC, Standard Procedure for Oconee, McGuire and Catawba Nuclear Stations (SPOMCNS), Access Controls for High, Extra High, and Very High Radiation Areas, Procedure No. SH/0/B/2000/012, Rev. 003
DPC, SPOMCNS, Preparation of a Radiation Work Permit (RWP), Procedure No. SH/0/B/2000/003, Rev. 006
Duke Power Quality Assurance Program Related (DPQAPR), Nuclear Policy Manual (NPM), Nuclear System Directive (NSD): 208, Problem Investigation Process (PIP), Rev. 27
DPQAPR, NPM, NSD: 210, Corrective Action Program, Rev. 4
DPQAPR, NPM, NSD: 223, Trending Program, Rev. 4

Radiation Work Permit (RWP) Documents

RWP No. 6300, Inspections, Surveillance & Firewatch
RWP No. 6301, Radiation Protection Surveillance
RWP No. 6302, Radiography Testing

Corrective Action Program (CAP) Documents

PIP O-04-06988, RP held up sequence for installing transfer tube covers due to high radiation levels found at the deep end ladder extensions on the east and west ladder
PIP O-04-07239, A high radiation area posting was found on the floor
PIP O-04-07474, RP discovered contamination in a clean room while performing investigative surveillance
PIP O-04-07477, Contamination found in designated clean area room
PIP O-04-07549, Worker alarmed portal monitor
PIP O-04-08431, An unauthorized individual was found inside the radiography boundary during a source exposure
PIP O-04-08439, An individual walked up to a boundary rope, grabbed it and leaned over it
PIP O-04-08554, Contamination was found in clean areas

Section 2OS2: ALARA Planning and Controls

Procedures, Guidance Documents, and Manuals

DPC, ONS, Incore Detector Assembly Withdrawal and Insertion, Procedure No. IP/0/A/0302/004B
DPC, ONS, Body Burden Analysis-Evaluation of Results, Procedure No. HP/0/B/1000/063, Rev. 018
DPC, ONS, Procedure for Quantifying Airborne Radioactivity, Procedure No. HP/0/B/1010/057, Rev. 031
DPC, ONS, Radiological Protection Requirements for Incore Detector Work, Procedure No. HP/0/B/1000/104, Rev. 004
DPC, ONS, Radiological Protection Requirements for Steam Generator Maintenance, Procedure No. HP/0/B/1000/016, Rev. 020
DPC, SPOMCNS, Access Controls for High, Extra High, and Very High Radiation Areas, Procedure No. SH/0/B/2000/012, Rev. 003
DPC, SPOMCNS, Internal Dose Assessment, Procedure No. SH/0/B/2001/001, Rev. 002
DPC, SPOMCNS, Investigation of Skin and Clothing Contaminations, Procedure No. SH/0/B/2001/003, Rev. 006
DPC, SPOMCNS, Investigation of Unusual Radiological Occurrences, Procedure No. SH/0/B/2001/004, Rev. 006
Duke Power Company System ALARA Manual, For Use in the Design, Construction, Operation, and Decommissioning of Nuclear Power Stations and Supporting Facilities, Rev. 16
DPQAPR, NPM, NSD: 208, PIP, Rev. 27
DPQAPR, NPM, NSD: 210, Corrective Action Program, Rev. 4
DPQAPR, NPM, NSD: 223, Trending Program, Rev. 4

ALARA Pre-Planning and Planning Worksheets

Inspections/Surveillance/Firewatch/Engineering/Confined Space/Toolroom Attendant for RWP No. 6300
Install and Remove Scaffolding for RWP No. 6302
RCS Pipe Cutting/Machining/Welding for RWP No. 6310
Radiography Testing for RWP No. 6302
Remove/Install RCS Temporary/Permanent Supports for RWP No. 6308

Rig/Remove Original Steam Generator Transport/Store for RWP No. 6318

RWPs

RWP No. 6300, Inspections/Surveillance/Firewatch/Engineering/Confined Space/Toolroom Attendant
RWP No. 6302, Radiography Testing
RWP No. 6304, Decon Activities
RWP No. 6305, Install and Remove Scaffolding
RWP No. 6306, Remove and Install Insulation
RWP No. 6308, Remove/Install RCS Temporary/Permanent Supports
RWP No. 6309, Remove/Install Large Bore Piping Secondary Temp/Perm Restraints/Install Seal Plates on MS Pipe End
RWP No. 6310, RCS Pipe Cutting/Machining/Welding
RWP No. 6311, Remove/Install Small Bore Piping
RWP No. 6318, Rig/Remove Original Steam Generator Transport/Store
RWP No. 6319, Shielding Activities

Records and Data

4th Quarter ALARA Committee Meeting Agenda
DPC, ONS, HP Derived Air Concentration Report, U3 Reactor Building 4th Floor (Routine, Sample Nos. 041127052, Dated 11/27/04
DPC, ONS, RP Area Samples for U3 Reactor Building 1st Floor (Routine), Sample Nos. 041127055 and 041127071, Dated 11/27/04
DPC, ONS, RP Area Samples for U3 Reactor Building 2nd Floor (Routine), Sample Nos. 041127060 and 041127070, Dated 11/27/04
DPC, ONS, RP Area Samples for U3 Reactor Building 3rd Floor (Routine), Sample Nos. 041127039, 041127042, 041127046, 041127054, 041127058, and 041127075, Dated 11/27/04
DPC, ONS, RP Area Samples for U3 Reactor Building 4th Floor (Routine), Sample Nos. 041127061 and 041127073, Dated 11/27/04
DPC, ONS, RP Area Samples for U3 Reactor Building A Cavity (Routine), Sample No. 041127051, Dated 11/27/04
DPC, ONS, RP Area Samples for U3 Reactor Building B Cavity (Routine), Sample No. 041127053, Dated 11/27/04
DPC, ONS, RP Area Samples for U3 Reactor Building Basement (Routine), Sample Nos. 041127059 and 041127072, Dated 11/27/04
Dose Due to Internally Deposited Alpha Emitters Based on ONS Weighted Alpha DAC for selected individuals associated with 11/27/04 airborne event in the U3 Reactor Building (8.29 E-05, 8.62E-05, 3.81E-05, 3.55E-05, and 3.45E-05 microcuries)
RP & Safety Daily Status Reports, Dated 12/08/04 and 12/10/04
U3 EOC-21 Outage Meeting Agendas, Dated 12/07/04 and 12/10/04

CAP Documents

PIP O-04–6975, The refueling canal contamination levels were approximately 20 times higher than expected
PIP O-04-08177, U3 Reactor Building was evacuated due to high contamination and

airborne radiation levels
PIP O-04-08480, 3RIA-5 went into an alarm on high dose rate while the incore wires were being pulled
PIP O-04-08555, Operating experience indicates that dose rate reductions can be obtained by backflushing the LD Coolers and associated piping

Section 4OA5.6: Containment Restoration Activities

Modification Package ON-33086, Containment Opening, Part AS9, Revision 1, including 10 CFR 50.59 Screening Document

Work Package 33555, Unit 3 Construction Opening Steel Liner Installation

Work Package 33550, Unit 3 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 2

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 Ten SGT Rebar Splicers

Tensile Test Results for Three Rebar Sister Splices

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 4

Procedure BPI-GRIP Systems Splicing Manual and Operating Instructions, Revision 10/18/01

BarSplice Installation and Examination of Swaged Mechanical Splices Supplemental Requirements for the Oconee Nuclear Station, Revision 0

NDE Examiner Qualification Records for the following SGT NDE Examiners: 3 Level II VT and MT Examiners; 1 Level II RT Examiner, and 2 Level III Examiners

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

Final Surface Magnetic Particle Examination Reports for Liner Plate Welds LP-1, LP-2, LP-3, and LP-4

Certification Records for MT Yokes SGT-0041and SGT-0045

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 001, 002, 003, 008, and 022

Receipt Inspection Reports and Certified Material Test Reports for 1/8" E7018 - Lot 4K312C03 (Heat 23462) and 3/32" E7018 - Lot 2G308C05 (Heat 150357) Welding Electrodes

Section 4OA3.4 (.5, .6, and .7): CRDM Leakage

PIPs

O-01-00587, Evidence of primary leakage at base of reactor head/CRDM nozzle penetrations. (Unit 3 root cause for the February 2001 forced outage)
O-01-01121, Reactor vessel closure heads for Units 1, 2 and 3 should be declared A(1) due to primary pressure boundary leaks on nozzle penetrations.
O-01-01455, Evidence of primary leakage at base of reactor head/CRDM nozzle penetrations. (Unit 2 root cause for the February 2001 forced outage)
O-01-04546, Flaw indications on CRDM Nozzle #2 are inconsistent with damage results expected after 7 months of operation. (Root Cause for Unit 3 Nozzle #2)
O-01-04220, Evidence of through wall leakage on primary pressure boundary. (Unit 3 root cause for the Fall 2001 outage)

Other

Oconee Unit 3 CRDM Nozzle Ultrasonic Examination Results (Top Down Tool) (Nozzle 2 portion) dated November 20, 2001
Unit 3 RV Head Timeline for 1988 through 2003
Visual Examination for Leakage of PWR Reactor Head Penetrations (EPRI) dated August 2001
Visual Examination for Leakage of PWR Reactor Head Penetrations (EPRI) dated March 2003
Calculation 32-5012403-00-00, OC-3 CRDM Nozzle Circumferential Flaw Evaluation (proprietary)

Section 4OA5.7: NRC Bulletin 2004-01

Duke Energy Response to NRC BL 2004-01
Alloy 600 Program Health Report

Section 4OA5.9: Welding, NDE, PSI

Procedures

SGT Procedure QEP 12.03, Rev.0E3, Visual Examination
SGT Procedure QEP 12.04, Rev. 3, Liquid Penetrant Examination
SGT Procedure QEP 12.05, Rev.3E1, Magnetic Particle Examination
SGT Procedure QEP 12.06, Rev. 2, Radiographic Examination (ASME)
SGT Procedure QEO 12.08, Rev. 2E1, Ultrasonic Thickness Examination
SGT Procedure QEP 12.09, Rev. 1, Manual Ultrasonic Examination of ASME Section III Pipe and Vessel Welds
SGT Procedure QEP 15.01, Rev. 4/AFU, Identification and Control of Deviations
SGT Welding Procedure Specifications (WPS) and Procedure Qualification Records (PQR)
GT/1.3-1 and PQR 55-PQ7180-01, GT-SM/1.3-1 and PQRs 55-PQ4665-00 and 55-PQ7186-00, GT/CLAD 1.3-1 and PQRs 55-PQ7172-01 and 55-PQ7173-01, GT/CLAD 1.3-2 and PQRs 55-PQ7172-01 and 55-PQ7173-01.

Other Documents Reviewed

PIPs O-04-07288, O-04-06596, O-04-02608, O-04-03435, O-04-03060, O-04-03177, O-04-03079, O-04-03959, O-04-03024, O-04-07519, O-03-06840, O-03-07044, O-03-07158, and O-03-07838
SGT NCRs 03-026, 03-071, 03-063, 03-055, 03-069, and 02-119,
B & W Report BWC-TR-2004-05 and 06, Rev. 0, Technical Summary of Bobbin and X-Probe Exams for Replace Steam Generators
Work Packages 33065A, 33065B, 3067A, 33080A, and 33085B
Reports for PT, MT, VT, RT, and UT
RT films reviewed for welds: Hot Legs 3RC-0283-5V and -6V; Cold Leg 3RC-0283-9V; Main Steam Line 3-MS-0138-20V; and Feed Water Line 3-FDW-0268-48V

Section 4OA5.10: Review of Pipe Supports Related to Steam Generator Replacement

Procedures

SGT Procedure QEP 12.03, Rev. 5E2/AFU, Visual Weld and Hanger Examination
SGT Procedure QEP 12.12, Rev. 0/AFU, ASME Section XI Visual Examination (VT-1 and VT-3)
SGT Procedure QEP 07.08-1, Rev. 0E1/AFU, Conceptual / Final Scope Document (CSD/FSD) for Modification No. ON-23086 for Unit 2
SGT Procedure QEP 15.01, Rev. 4/AFU, Identification and Control of Deviations

Other Documents Reviewed

PIP O-04-06744 for Unit 3
PIPs O-04-01572, -02566, and -03519 for Unit 2
SGT NCRs 03-008, 03-009, 03-010, 03-011, 03-013, 03-015, 03-017, 03-021, 03-023, 03-024, 03-025, 03-026, 03-030, 03-031, 03-033, 03-036, 03-038, 03-041, 03-047, 03-048, 03-056, 03-057, 03-070, and 03-077 for Unit 3.
SGT NCRS 02-005, 02-008, 02-022, 02-028, 02-042, 02-044, 02-056, 02-091, 02-097, 02-101, 02-108, 02-145, 02-149, 02-150, 02-151, 02-155, 02-0156, 02-0159, 02-0160, 02-162, and 02-

164, 02-041, 02-078, 02-081, 02-119, 02-146, 02-152, and 02-165.

LIST OF ACRONYMS

ADAMS	-	Agency wide Documents Access and Management System
ALARA	-	As Low As Reasonable Achievable
ANSI	-	American National Standards Institute
ARM	-	Area Radiation Monitor
AP	-	Abnormal Procedure
ASME	-	American Society of Mechanical Engineers
ASTM	-	American Society for Testing and Materials
ASW	-	Auxiliary Service Water
BACC	-	Boric Acid Corrosion Control
BHUT	-	Bleed Holdup Tank
BMV	-	Bare Metal Visual
BWST	-	Borated Water Storage Tank
CAM	-	Continuous Airborne Monitor
CAP	-	Corrective Action Program
CCW	-	Condenser Circulating Water
CFR	-	Code of Federal Regulations
CRDM	-	Control Rod Drive Mechanism
DEC	-	Duke Energy Corporation
ECCS	-	Emergency Core Cooling System
ED	-	Electronic Dosimeter
EDG	-	Emergency Diesel Generator
EHRA	-	Extra High Radiation Area
EOC	-	End of Cycle
EFW	-	Emergency Feedwater
FDW	-	Feedwater
FME	-	Foreign Material Exclusion
FTC	-	Fuel Transfer Cannel
GPM	-	Gallons per Minute
HP	-	Health Physics
HPI	-	High Pressure Injection
HPSW	-	High Pressure Service Water
HPT	-	Health Physics Technician
HRA	-	High Radiation Area
HX	-	Heat Exchanger
ICS	-	Integrated Control
IP		Inspection Procedure
IR		Inspection Report
ISI	-	Inservice Inspection
IST	-	Inservice Testing
KHU	-	Keowee Hydroelectric Unit
kV	-	Kilo Volt
LCO	-	Limiting Condition for Operation
LDST	-	Letdown Storage Tank
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
NIST	-	National Institute of Standards and Technology
NOUE	-	Notification of Unusual Event
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
ODCM	-	Offsite Dose Calculation Manual
ONS	-	Oconee Nuclear Station
OS	-	Occupational Radiation Safety
OOS	-	Out of Service
OTSG	-	Once-Through Steam Generator
PARS	-	Publicly Available Records
PASS	-	Post Accident Sampling System
PCM	-	Personnel Contamination Monitor
PI	-	Performance Indicator
PIP	-	Problem Investigation Process report
PM	-	Preventive Maintenance
PMT	-	Post-Maintenance Testing
PSI	-	Pre-Service Inspections
PT	-	Liquid Penetrant
PWHT	-	Post Weld Heat Treatment
QC	-	Quality Control
RA	-	Radiation Area
RBES	-	Reactor Building Emergency Sump
RBS	-	Reactor Building Spray
RCMUP	-	Reactor Coolant Makeup Pump
RCA	-	Radiologically Controlled Area
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
REMP	-	Radiological Environmental Monitoring Program
RFO	-	Refueling Outage
RG	-	Regulatory Guide
RII	-	Region II
RP	-	Radiation Protection
RPV	-	Reactor Pressure Vessel
RT	-	Radiograph Examination
RTP	-	Rated Thermal Power
RV	-	Reactor Vessel
RWP	-	Radiation Work Permit
SCBA	-	Self-Contained Breathing Apparatus
SDP	-	Significance Determination Process
SG	-	Steam Generator
SGR	-	Steam Generator Replacement

SGRP	-	Steam Generator Replacement Project
SLC	-	Selected Licensee Commitments
SSC	-	Structure, System and Component
SSF	-	Standby Shutdown Facility
Tave	-	Average RCS Temperature
TDEFW	-	Turbine Driven Emergency Feedwater
TI	-	Temporary Instruction
TLD	-	Thermoluminescent Dosimeter
TS	-	Technical Specification
TSAIL	-	Technical Specification Action Item Log
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
UT	-	Ultra Sonic
VHRA	-	Very High Radiation Area
WANO	-	World Association of Nuclear Operators
WBC	-	Whole Body Counter
WO	-	Work Order