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

February 3, 2003

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

SUBJECT: OCONEE NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 50-269/02-05, 50-270/02-05, AND 50-287/02-05

Dear Mr. Jones:

On January 4, 2003, the NRC completed an inspection at your Oconee Nuclear Station. The enclosed report documents the inspection findings which were discussed on January 14, 2003, with Mr. Bruce Hamilton 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 two NRC-identified and three self-revealing findings of very low safety significance (Green). Four of these findings were determined to involve violations of NRC requirements. However, because of the 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, four licensee identified NCVs are listed in Section 4OA7 of this report. If you contest any of the NCVs 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, DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Oconee facility.

Since the terrorist attacks on September 11, 2001, the USNRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The USNRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) '02, and the remaining inspections are scheduled for completion in CY '03. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY ‘03, the USNRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the USNRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

Docket Nos.: 50-269, 50-270, 50-287, 72-04
License Nos.: DPR-38, DPR-47, DPR-55

Enclosure: NRC Integrated Inspection Report 50-269/02-05, 50-270/02-05, and 50-287/02-05 w/Attachment - Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-269, 50-270, 50-287, 72-04
License Nos:	DPR-38, DPR-47, DPR-55
Report No:	50-269/02-05, 50-270/02-05, 50-287/02-05
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3 and Independent Spent Fuel Storage Installation
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	September 29, 2002 - January 4, 2003
Inspectors:	M. Shannon, Senior Resident Inspector S. Freeman, Resident Inspector E. Christnot, Resident Inspector K. Green-Bates, Project Engineer (Sections 1R08.2, 4OA3.4, 4OA5.3 and 4OA7) J. Ennis, Physical Security Inspector (Sections 4OA3.3 and 4OA5.1) D. Forbes, Physical Security Inspector (Section 4OA5.1) D. Jones, Senior Health Physicist (Sections 2OS1 and 2PS1) J. Kreh, Radiation Specialist (Sections 2PS3, 4OA1.1, and 4OA1.2) G. Kuzo, Senior Health Physicist (Sections 2OS3, 2PS1, 4OA1.1 and 4OA1.2) W. Rogers, Senior Reactor Analyst (Section 4OA5.2) S. Vias, Senior Reactor Inspector (Section 1R08.1) R. Chou, Reactor Inspector (Section 1R08.1)
Approved by:	Robert Haag, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000269/02-05, IR 05000270/02-05, IR 05000287/02-05, Duke Energy Corporation, 09/29/2002 - 01/04/2003, Oconee Nuclear Station; Inservice Inspection, Maintenance Effectiveness, and Surveillance Testing.

The inspection was conducted by the resident Inspectors and seven regional based inspectors: a project engineer, one physical security inspector, two reactor inspectors, and three health physicists. Five Green findings were identified, four of which were non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using the Significance Determination Process (SDP) found in Inspection Manual Chapter 0609. 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. Inspector Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding for the licensee’s failure to perform timely/effective corrective actions when dispositioning a component with identified ASME Code deficiencies and non-compliances.

  A non-cited violation of 10 CFR50, Appendix B, Criterion XVI, Corrective Actions, was identified with respect to the failure to perform timely/effective corrective actions. The violation is greater than minor because it is associated with the mitigating system cornerstone attributes and affected the cornerstone objective to ensure availability, reliability, and capability of the pressure boundary portion of a component used during Unit 1 design basis events. This finding was considered to be of very low safety significance because it was concluded that the component (1B condenser circulating water pump) could perform its intended pressure boundary safety function and that the issue could be resolved with NRC approval of relief requests. (Section 1R08.2)

- Green. An inadequately installed chain operator on atmospheric dump valve (ADV) block bypass valve 1MS-163 resulted in not having the ADVs available for both steam generators on Unit 1 operable during a mode change.

  A non-cited violation was identified for conducting a mode change without having the ADVs operable, as prescribed in Technical Specification (TS) 3.0.4 and TS 3.7.4. The violation affected the objective of the mitigating system cornerstone to protect against external factors (i.e., tornado) and was therefore, more than minor. This self-revealing finding was determined to be of very low significance due to the short exposure time and the limited initiating events affected by the loss of the ADV. (Section 1R12.1)

- Green. The licensee failed to correct a water intrusion problem following identification in 1998, 1999, and 2000 that water was entering the Units 1 and 2 turbine driven emergency feedwater (EFW) pump lube oil sumps.

A non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, requirements was identified for failure to identify the source of the water intrusion, failure to identify the rate of water intrusion, and failure to correct the condition adverse to quality. Water in the turbine driven EFW pump lube oil sumps had a credible affect on the operability, availability, reliability and function of the TDEFW mitigation system and was therefore, more than minor. This finding was determined to be of very low safety significance due to the multiple trains of equipment capable of performing secondary side heat removal not affected by the performance deficiency. This included two trains of motor driven EFW pumps per unit, potential cross connect of EFW between units, and the standby shutdown facility. (Section 1R12.2)

- <u>Green</u>. An inadequacy in the licensee's work planning program resulted in a missed Technical Specification (TS) required surveillance test involving the Keowee Hydro Station overhead power path.

  A non-cited violation of TS surveillance requirements (SR) 3.3.19.1, Channel Functional Test for Degraded Grid Voltage Protection Actuation Logic Channels, SR 3.8.1.15, 230kV Circuit Breaker Actuation on Switchyard Isolation, and TS 5.5.18, Keowee Hydo Unit Commercial Power Generation Testing Program, was identified when it was discovered that PT/0/A/610/022, Keowee Over Frequency Protection Functional Test, was not performed within the required TS SR frequency. This violation is more than minor because it affected the mitigating system cornerstone objective of equipment reliability, in that, a complex series of tests for the emergency power supply were not performed within the specified frequency. This self-revealing finding was determined to be of very low safety significance based on the fact that there was no unavailability of the Keowee units resulting from the missed surveillances. (Section 1R22.2)

Cornerstone: Reactor Safety/Barrier Integrity

- <u>Green</u>. A self-revealing finding was identified for the failure of a steam generator tube to successfully meet the "3 times normal operating delta-p pressure" (3ΔP) test criterion (4250 psid) during the in-situ pressure testing process. A performance deficiency was identified, in that the in-service inspection procedures did not have enough guidance to be able to identify a defect in this tube the previous outage; thereby, allowing the unit to operate last cycle with one tube that may not have met the 3ΔP limit the entire cycle.

  The finding was of very low safety significance because, the tube did not fail the performance criterion of meeting the "accident leakage limit." Specifically, having ruptured at a test pressure of 3987, the tube exceeded the normal operating delta pressure (1490 psid), main steam line break/faulted condition (2898 psid), and the main feedwater anticipated transient without scram analysis pressure (~1500 psid). In addition, the unit exhibited no signs of leakage during the last operating cycle from this tube. (Section 1R08.1)

B. <u>Licensee Identified Violations</u>

Four violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7.

Report Details

Summary of Plant Status:

Unit 1 operated at or near 100 percent rated thermal power (RTP) during the entire inspection period.

Unit 2 began the inspection period at 98.6 percent RTP in a coastdown mode for the end-of-cycle, (EOC)19 refueling outage. The unit remained in the coastdown mode until October 12, 2002, when the unit was shutdown. On November 22, 2002, the unit was taken critical and returned to 100 percent RTP on November 25, 2002. The unit operated at or near 100 percent RTP during the remainder of the inspection period.

Unit 3 operated at or near 100 percent RTP during the entire inspection period except for one reactor trip and resulting forced outage. The unit tripped on November 14, 2002, from a main turbine trip causing a reactor trip. The unit entered a forced outage to identify the cause of the trip and to effect repairs. Following repairs, the unit was taken critical on November 16, 2002, and returned to 100 percent on November 18, 2002.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

.1 Cold Weather Preparations

a. Inspection Scope

The inspector reviewed the licensee’s preparations to protect the Units 1, 2, and 3 siphon seal water (SSW) and essential siphon vacuum (ESV) systems, two systems per unit that are important to safety, from freezing during cold weather conditions. The review included: the system drawings, the procedures used to check operation of the heat trace circuits, a sample of the work orders (WO) used for checking the proper operation of the heat trace circuits, the calibration data for the associated alarms, and Problem Identification Process reports (PIPs) initiated that involved freeze protection activities. The inspectors also walked down/visually inspected associated heat traced piping to ensure proper insulation installation, the heat trace alarm panels for abnormal alarms, the electrical alignment of the heat trace breaker panels, the power supplies to ensure availability of electrical power, and the ESV building for proper heating. The intent of the review was to confirm that the licensee had completed preparations that would ensure that systems and components important to safety remained functional when challenged by adverse cold weather conditions. Specific documents reviewed included:

- IP/0/B/1601/09, Preventive Maintenance (PM) and Operational Check of Freeze Protection, Revision 14

- IP/0/B/1601/09A, Preventive Maintenance and Operational Check of QA-1 Freeze Protection, Revision 2
- IP/0/B/1601/10, Preventive Maintenance and Operational Check of Process Heat Trace, Revision 10
- WO 98509819, Units 1, 2, and 3 Process Heat Trace PM
- WO 98482543, Unit 1 Freeze Protection PM
- WO 98491590, Unit 2 Freeze Protection PM
- WO 98496005, Unit 3 Freeze Protection PM

b. Findings

No findings of significance were identified

.2 Adverse Weather Condition

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the adverse weather condition abnormal procedure for high winds in the area (exceeding 60 mph) following a warning from the national weather service, which occurred on the morning of December 13, 2002. Included in the review were the verification that the operator's actions specified in the abnormal procedure were taken in a timely manner prior to and during the high winds. Adequate operator staffing was maintained throughout the adverse weather condition. The inspectors assessed if any plant modifications, new evaluations, procedure revisions, or operator workarounds that would pose a challenge to safe plant operation related to the high winds condition.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

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

- Unit 2 low pressure injection (LPI) system prior to reactor vessel drain down

- Units 1 and 3 offsite and 235 Kv switchyard electrical power system lineup during yellow bus isolation to repair degraded grid phase X voltage detector

- Unit 1 low pressure service water system

b. Findings

No findings of significance were identified

.2 Complete Walkdown

a. Inspection Scope

The inspectors performed a detailed system walkdown on accessible portions of the Unit 1 emergency feedwater (EFW) system. The inspectors focused on verifying adequate material condition and correct system alignment. The inspectors' main focus was on the newly installed Automatic Feedwater Isolation System (AFIS). The inspectors reviewed system operating procedures, surveillance procedures, instrumentation procedures, Technical Specifications (TS), PIPs, as well as:

Updated Final Safety Analysis Report (UFSAR) Sections

6.2.1.4.4, Description of Blowdown Model (AFIS to isolate affected steam generators) - Table 6-32, Steam Line Break Mass and Energy Releases
7.4.3, Emergency Feedwater Controls
7.5.2.5, Display Instrumentation - Steam Generator Pressure
10.1, Steam and Power Conversion System
10.3, Main Steam System
10.4.6, Condensate and Main Feedwater System
10.4.7, Emergency Feedwater System
15.13, Steam Line Break Accident

Drawings

OFD-121A-1.8, Unit 1 Flow Diagram of Condensate System (Condensate Make-up and Emergency Feedwater Pump Suction), Revision 15
OFD-121D-1.1, Unit 1 Flow Diagram of Emergency Feedwater System, Revision 25

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 of selected areas 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. Inspection of the following areas were conducted during this inspection period.

- Unit 1 and 2 Control Room Areas, including the Technical Support Center (2 inspection areas)

- Unit 3 Control Room Areas, including the Operations Support Center (2 inspection areas)

- Keowee Hydro-Station Unit 1, including Control Room Area (2 inspection areas)

- Units 1 and 2 Auxiliary Building 6th floor, including the Spent Fuel Pool Area (2 inspection areas)

- Essential Siphon Vacuum and Siphon Seal Water Building (1 inspection area)

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI)

.1 Unit 2 Steam Generators (SGs)

a. Inspection Scope

The inspectors observed activities and reviewed selected inspection records for the eddy current examination (ET) of the SGs for 2EOC19 outage. The records were compared to the Technical Specifications (TS), license amendments, and applicable industry established performance criteria to verify compliance. Qualification and certification records for examiners, equipment and procedures for the above eddy current examination activities were reviewed. Approximately 25 examples of bobbin and rotating coil inspection ET data were reviewed and discussions held with appropriate personnel to evaluate the adequacy of data analysis including acquisition, primary analysis, resolution and quality data assurance. In addition, the inspectors reviewed the licensee's selection criteria for SG tubes to be plugged and in-situ tested during the 1EOC20 refueling outage. The observations and records were compared to the TS and the applicable Code (ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, with no Addenda) to verify compliance.

The inspectors also reviewed the licensee's past Quality Assurance Surveillance Checklist for 3EOC19, 1EOC20 and 2EOC18 Eddy Current Acquisition. The inspectors used those procedures and documents listed in the attachment to evaluate the implementation of the licensee's SG ISI program and associated activities.

Additionally, the inspectors reviewed activities relative to in-situ pressure testing of 21 Unit 2 SG tubes.

b. Findings

Introduction: A Green finding was identified for the failure of a steam generator tube to successfully meet "3 times normal operating delta-p pressure (3ΔP)" (4250 psid) test criterion during the in-situ pressure testing process.

Description: During in-situ pressure testing of 21 tubes of interest during 2EOC19 outage, SG 2B tube 37-27 began to leak at approximately 3900 psid and ultimately burst. This did not meet the "3 times normal operating delta-p pressure" (4250 psid) test criterion. The failure was at an axially oriented indication in a dent with manufacture burnish marks (MBM) superimposed over the dent. The defect was initially identified by ECT and measured as a 2" long single axial indication, 95% through wall (maximum depth), in a dent location just above the 15th support plate. This tube was subsequently removed from service by plugging. After existing data was reviewed, 28 other tubes having indications of dents and MBM that overlapped were preventatively plugged. The review of Unit 1 found 13 locations where dent and MBM indications overlapped but none appeared to contain defects as was seen on the Unit 2 SGs. Unit 3 revealed no similar overlapping dent and MBM indications.

Analysis: The inspectors determined this finding was of very low safety significance because, during the in-situ pressure testing, the test pressure exceeded the Normal Operating delta pressure (1490 psid), Main Steam Line Break/Faulted Condition (2898 psid), and the Main Feedwater Anticipated Transient Without Scram analysis pressure (~1500 psid), but ruptured at 3987 psid, which was less than the 3ΔP Structural Limit (4250 psid). Therefore this tube did not fail the performance criterion of meeting the "accident leakage limit." In addition, the unit exhibited no signs of leakage during last cycle from this tube. A performance deficiency was identified in that the ISI procedures did not have sufficient guidance to be able to identify the defect in this tube during the previous outage, therefore allowing the unit to operate last cycle with one tube (37-27) in SG 2B, that may not have met the 3ΔP limit the entire cycle. Thus, the finding was evaluated as Green (very low safety significance). This issue is in the licensee's corrective action program as PIP O-02-06118 and Licensee Event Report (LER) 50-270/02-03-00.

Enforcement: The inspectors determined that the finding did not represent a non-compliance with the regulations, but did fail to meet industry guidelines as stated in Nuclear Energy Institute (NEI) 97-06 R/1, In-Situ Pressure Testing. This guidance was established to ensure SG tube structural and leakage integrity is maintained as implemented by Steam Generator Management Program104 “Condition Monitoring” and specifies that the tubes meet 3ΔP Structural Limit and EPRI PWR S/G Examination Guidelines, Revision 5.

.2 Program Review

a. Inspection Scope

The inspectors observed in-process ISI work activities and reviewed selected ISI records. The observations and records were compared to the TS and applicable third ISI interval required ASME Boiler and Pressure Vessel Codes, (1989 Edition and 1995 Edition, 1996 Addenda), to verify compliance.

The inspectors observed in-process acquisition and analysis of Framatome’s ultrasonic (UT) examination of reactor vessel head control rod drive mechanism (CRDM) nozzles using the remote automated “ACCUSONEX” data acquisition and analysis system to detect and characterize flaws. Additionally, the inspectors observed the ultrasonic examination of a previously repaired nozzle and reviewed selected liquid dye-penetrant (PT) examination data of reactor pressure vessel (RPV) head penetration welds.

The inspectors also observed and reviewed magnetic particle (MT) examinations of:

Reactor head bolts ID 2-RPV-26-204-46, 47 and 48(9.25 inch diameter ASME Class 1 reactor head bolts).

The inspectors observed the calibration, manual UT examination, and radiographic record for the following Class 1 pipe weld Weld 2-LP-0189-15 (Ten inch ASME Class I low pressure injection system outlet weld for valve 2LP-47).

Additionally, the inspectors reviewed the following weld specification procedures, procedure qualification records, and radiographs for compliance with applicable codes for the following pipe welds:

Weld 2-RC-0266-21	Inlet weld for ASME Class I pressurizer valve 2RC-1
Weld 2-RC-0266-22	Outlet weld for ASME Class I pressurizer valve 2RC-1
Weld 2-RC-0253-5	Butt weld for ASME Class I Auxiliary pressurizer spray line piping

Certification records for equipment and consumables, and the non-destructive examination (NDE) procedures for the above ISI examination activities were reviewed. Selected corrective action reports concerning ISI, ASME code, and reactor vessel head issues were reviewed by the inspectors.

b. Findings

Introduction: A Green non-cited violation (NCV) was identified for a failure to take timely/effective corrective actions when dispositioning a component with identified ASME Code deficiencies and non-compliances.

Description: The 1B condenser circulating water (CCW) pump is used for mitigating Unit 1 design basis events, including fire, loss of coolant accidents (LOCAs), loss of offsite power (LOOP), and LOCA/LOOP by providing a pressure boundary conduit for transporting water from the lake to appropriate safety/risk significant areas of the plant. Plant design bases delineate this pump as part of the emergency condenser circulating water (ECCW) siphon header for which TS 3.7.8 requires the ECCW system to be operable when in Modes 1-4. In June 2000, this QA-1 pump had pressure boundary welds repaired by a non-qualified vendor shop after which the pump was reinstalled. On May 15, 2001, the licensee wrote PIP O-01-1876, which documented six potential issues (identified by the American Nuclear Insurance Inspector) where the weld repair and subsequent required NDE performed by the non-qualified vendor shop did not meet the site 1989 Section XI ASME Code repair & replacement program requirements.

Additionally, the inspectors noted that the licensee had identified in PIP O-01-1876 a potential 10 CFR Part 21 hydrogen embrittlement corrosion issue for other site pumps (i.e., auxiliary service water) repaired by this vendor. The concern had not been closed out in the PIP, had no corrective actions assigned to it within the PIP, and there was no documentation within the PIP to connect the stated Part 21 problem to any other plant corrective actions or PIPs.

PIP O-01-1876 had been subdivided into two main categories: (1) actions to address the vendor oversite failure; and (2) actions to address the areas where the CCW pump repairs did not meet the licensee's repair and replacement program ASME Code requirements. The inspectors noted that while efforts to correct the vendor problem appeared to be actively underway and were being reviewed by management, efforts to disposition the technical and regulatory issues of the six potential ASME non-compliances stated in the PIP and to bring the pump into compliance appeared to have languished. Subsequent interviews with licensee personnel found that some additional work had been done to disposition some of the six identified Code problems and to correct the Part 21 corrosion issue raised in the PIP. However, the corrective action program process had not been used effectively, in that PIP O-01-1876 was not updated to add the new information and thus resolve, complete, and closeout some of the identified problems in a timely fashion.

Therefore, the 1B CCW pump had been repaired and installed in June 2000, and had been in service for 28 months, without clear Code verification that it could perform its design basis pressure boundary safety function. The operability evaluation contained within the PIP had no technical documentation or calculations to estimate and justify how long the non-Code repaired welds, which had not received a Code NDE, could remain functional to withstand design basis conditions. Futhermore, although a large portion of the welds are submerged, there was no time limit for leaving the non-compliant pump in service before another operating evaluation was required to reevaluate the pressure boundary condition for corrosion issues, etc. The inspectors concluded that 17 months was untimely and that as a result of the lengthy dispositioning of the problem, one possible opportunity to correct the issue during a subsequent Unit 1 outage had been missed.

As a result of the inspectors' questions, the licensee reviewed and dispositioned the CCW ASME Code pump issue and concluded that relief requests were to be submitted to correct two of the ASME non-compliance issues. In December, the inspectors reviewed two submitted CCW Code relief requests (2002-009 & -010, dated 12/16/02) and observed that the acceptable quality of the non-Code welds was based in part on the rationale that the non-compliant pressure boundary welds had successfully passed NDE examinations. The inspectors were concerned with this statement because, as identified by the licensee in PIP O-01-1876, all Section XI, IWA-4340 Repair and Replacement Program Code NDE requirements had not been met, as some of the pressure boundary welds had not received their required MT or PT examinations. However, neither the NDE issue, nor the basis of the dispositioning philosophy to waive the required Section XI NDE ASME Code requirements were discussed in the submitted relief requests. Therefore, the inspectors concluded that the two relief requests did not appear to be effectively prepared or reviewed against the site ASME Code requirements. The licensee opened PIP O-03-0185 to address this issue.

Analysis: The issue is considered more than minor because the finding is associated with the mitigating system cornerstone attributes and affected the cornerstone objective to ensure availability, reliability, and capability of the pressure boundary portion of a component used during Unit 1 design basis events (i.e., fire, LOCA, LOOP, and LOCA/LOOP). However, the conclusion that the pump could perform its intended safety function and that the issue could be resolved with NRC approval of relief requests, mitigated the finding to very low significance (Green) in accordance with the Significance Determination Process. The condition has been entered in the licensee's corrective action program under PIPs 0-C-02-06513, O-02-00826 and O-03-00185.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, requires in part that measures be established to assure that conditions adverse to quality, such as deficiencies, deviations and non-conformances are promptly identified and corrected. Contrary to the above, PIP O-01-1876 identified ASME Repair and Replacement Code non-compliance issues placed within the licensees corrective action program for the 1B CCW pump were not dispositioned or corrected in a prompt or timely manner, and Code resolution activities did not appear completely effective. Because the finding is of very low safety significance (Green) and is captured in the licensee's corrective action program, it is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. Accordingly, it is identified as NCV 50-269/02-05-01: Failure to Take Timely/Effective Corrective Actions When Dispositioning a Component with Identified ASME Code Deficiencies and Non-Compliances.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed simulator training on December 5, 2002. The scenario involved a reactor coolant system (RCS) break greater than maximum high pressure injection (HPI) flow but small enough to prevent the RCS from depressurizing below the LPI pump shutoff head. During the simulated event one motor driven EFW pump failed to start and one HPI pump tripped after starting. The inspectors observed crew performance in terms of: communications; ability to take timely and proper actions;

prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; and oversight and direction provided by the shift supervisor, including the ability to identify and implement appropriate TS actions.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

.1 Maintenance Effectiveness on SG Atmospheric Dump Valve Systems

a. Inspection Scope

The inspectors reviewed various problem reports related to the atmospheric steam dump systems in order to evaluate the effectiveness of the licensee's maintenance program.

b. Findings

Introduction: A Green NCV was identified for conducting a mode change without having the ADVs for both steam generators on Unit 1 operable, as prescribed in TS 3.0.4 and TS 3.7.4.

Description: On April 19, 2002, during a Unit 1 refueling outage, the licensee replaced the chain operator for ADV block valve bypass 1MS-163. During the installation, technicians had installed the chain operator bolts improperly such that they caught on the chain guard and prevented the valve from moving. The licensee did not discover the problem until the valve was tested on April 27, 2002. The chain operator was then repaired to allow proper operation of Valve 1MS-163.

On December 9, 2002, during review of PIPs related to the steam dump system and LER 50-269/02-05-00, (which involved a different problem with ADV 1MS-156), the inspectors noted that the licensee had identified the maintenance and operational problems with Valve 1MS-163 during the heatup of Unit 1, after the unit had entered Mode 3. The inspectors noted that the unit had been in Mode 5 at the time the original work was done. The unit entered Mode 4 on April 25, 2002, and began using the SGs for cooling. The unit subsequently entered Mode 3 (250°F, 350 psig) on April 26 and reached rated temperature and pressure (538°F, 2155 psig) on April 27 at 5:00 a.m. The licensee made final repairs to valve on day shift of April 27, 2002.

When using the ADVs, valve 1MS-163 must be opened first to equalize the pressure around the ADV block valve, 1MS-155 which then can be opened to allow use of the ADVs, 1MS-164 and 1MS-156. With Valve 1MS-163 unable to be opened, both ADVs were considered inoperable.

The inspectors determined that the licensee had not recognized that valve 1MS-163 needed to be tested following maintenance and prior to making a mode change. Because the valve was subsequently found to be inoperable, this condition was a violation of TS 3.0.4 for conducting a mode change with the ADVs inoperable.

Analysis: The inspectors determined that this finding was associated with program and process attributes and affected the objective of the mitigating system cornerstone to protect against external factors (i.e., tornado) and was therefore, more than minor. The inspectors determined that the inoperable valve, 1MS-163, would prevent use of the ADVs because high differential pressure would prevent the operators from opening ADV block valve 1MS-155 and thus prevent the use of the ADVs. Because both ADVs are needed for full mitigation credit for a steam generator tube rupture (SGTR) and one ADV is needed for a MSLB, the inspectors concluded that an actual loss of the safety function of the ADVs had occurred. This would affect the secondary heat removal and pressure equalization functions for SGTR and MSLB events. The inspectors performed a Phase 2 screening and determined the finding to be of very low significance (Green) due to the short exposure time and the limited initiating events affected by the loss of the ADVs.

Enforcement: TS 3.0.4 requires that, when an LCO is not met, entry into a mode of applicability is not permitted except when the actions for that mode of applicability permit operation for an unlimited amount of time. TS 3.7.4 requires that the ADV flow path for each steam generator be operable and with one or both paths are not operable, the required action is to be in Mode 3 within 12 hours and Mode 4 within 18 hours. The basis for TS 3.7.4 indicated that Valve 1MS-163 is part of the ADV flow path (atmospheric dump block valve bypass). Contrary to TS 3.0.4, Valve 1MS-163 was inoperable when Unit 1 entered Mode 3 with the steam generators relied on for cooling on April 26, 2002. Because the finding is of very low safety significance (Green) and is captured in the licensee’s corrective action program as PIP O-02-07047, it is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. Accordingly, it is identified as NCV 50-269/02-05-02: Improper Mode Change with Inoperable Atmospheric Dump Valve.

.2 Maintenance Effectiveness for Correcting the Water Intrusion Problem in the Units 1 and 2 Turbine Driven Emergency Feedwater Pump Lube Oil Sumps

a. Inspection Scope

The inspectors reviewed the oil analysis results from the turbine driven emergency feedwater pump lube oil sumps, specifically those analysis that indicated water intrusion into the lube oil sumps.

b. Findings

Introduction: A Green NCV of 10 CFR 50, Appendix B, Criterion XVI, requirements was identified for failure to identify the source and rate of the water intrusion and failure to correct the water intrusion problem following identification in 1998, 1999, and 2000 that water was entering the Units 1 and 2 turbine driven emergency feedwater pump lube oil sumps.

<u>Description:</u> On October 8, 2002, the licensee collected and analyzed oil samples from the Units 1, 2 and 3 turbine driven emergency feedwater (TDEFW) lube oil sumps. Excessive moisture content (greater than 9 percent) was reported in the Units 1 and 2 TDEFW lube oil sumps. Both lube oil sumps were subsequently placed on lube oil purification and the water was removed from the sumps.

The inspectors reviewed the previous TDEFW lube oil tank sample results and noted that excessive water content had previously been identified as follows: Unit 1, 7.2 percent on February 9, 1998, 9.2 percent in March 1999, and 7.5 percent on April 7, 1999; and Unit 2, 1 percent in January 2000. In addition several samples indicated water with concentrations at less than 1 percent in both units between 1998 and 2002. The inspectors noted that the licensee had not documented these adverse conditions (water found in the TDEFW lube oil sumps) in the corrective action program and the only corrective action was to remove the water by running the oil through the lube oil purification systems.

The inspectors noted that the lube oil analysis program was not effective in identification of water intrusion into the TDEFW lube oil sumps because lube oil samples were not taken after the pumps were run. Samples were often taken after the lube oil sumps had been placed on the weekly lube oil purification system for cleanup. The inspectors noted that because the preventive maintenance program was ineffective in identification of the water intrusion problem, effective maintenance to resolve the problem could not and was not pursued.

<u>Analysis:</u> For analysis purposes, the inspectors assumed the Unit 1 and Unit 2 TDEFW pumps had been inoperable since the date of the last surveillance runs until the sumps were cleaned by the lube oil purification systems (between 3-30 days). This was based on finding greater than 9 percent water in the sumps. Additionally, the inspectors concluded that the water intrusion into the TDEFW lube oil sumps had a credible impact on safety and was considered to have a credible affect on the operability, availability, reliability and function of the TDEFW mitigation system. For the Phase 1 screening, the high water concentration was considered to represent an actual loss of safety function, which required further evaluation. The finding was then processed through the Phase 2 SDP worksheets with an assumption that the TDEFW pumps were inoperable between 3-30 days. This finding was determined to be of very low safety significance (Green) based on the multiple trains of equipment capable of performing secondary side heat removal not affected by the performance deficiency. This included two trains of motor driven EFW per unit, potential cross connect of EFW between units, and the standby shutdown facility.

<u>Enforcement:</u> 10 CFR 50, Appendix B, Criterion XVI, Corrective Acton, requires that measures shall be established to assure that conditions adverse to quality, such as deficiencies, deviations, defective material and equipment and non-conformance's are promptly identified. The licensee's quality assurance program implements this requirement through Nuclear Station Directive 208, Problem investigation Process, Revision 22. Contrary to the above, following identification of an adverse condition (indication of significant water intrusion into the TDEFW lube oil sumps in 1998, 1999, and 2000), the licensee failed to identify the adverse condition in a PIP, and therefore did not take appropriate corrective actions to identify the source of the water intrusion, to

identify the rate at which the water was entering the sumps, and did not correct the condition adverse to quality. Because the finding is of very low safety significance (Green) and is captured in the licensee's corrective action program as PIP O-02-05306, it is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. Accordingly, it is identified as NCV 50-269,270/02-05-03: Failure to Identify and Correct the Turbine Driven Emergency Feedwater Lube Oil Sump Water Intrusion Adverse Condition.

1R13 Maintenance Risk Assessment and Emergent Work Evaluations

a. Inspection Scope

For selected structure, system and components (SSCs) the inspectors evaluated, as appropriate: (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. The following items were reviewed:

- PIP O-02-5208, Failure to close out Keowee Hydro Station (KHS) maintenance tasks resulted in a potential Orange risk condition when the Unit 1 turbine driven emergency feed water pump was being removed from service for train maintenance.

- PIP O-02-5245, Failure of the Anticipated Transient Without Scram (ATWS) Mitigation Systems Actuation Circuitry and Diverse Scram System resulting in the system being bypassed for repair activities.

- PIP O-02-5307, Failure of containment isolation valve 1RC-165 when the valve cycled from closed to open and back to closed when a different valve, 1RC-164, was opened for testing purposes.

- PIP O-02-5426, Possible Red Probablistic Risk Assessment (PRA) interaction with station Auxiliary Service Water (ASW) pump out of service for Unit 2 EOC19 with the Standby Shutdown Facility out of service for planned maintenance.

- WO 98513179, Isolation of the switchyard yellow bus for repairs to the degraded grid voltage detector.

- TT/2/A/0204/02, Reactor Building Spray (RBS) Pump Flow Test, Revision 1, special test of the 2A RBS pump resulting in an Orange risk condition while Unit 2 was in MODE 3.

- PIP O-02-6990, Work on Unit 1 inverter 1DIB originally classified as a green risk because the inverter was to be placed in the on AC Line MODE. Removal of the inverter from the safety function MODE, on DC Line, should have been classified as yellow.

- PIP O-02-6977, Procedure OP/0/A/1107/07, Loss of Normal Supply Power to 600V Safety Related Load Center, requires that breakers be removed and installed in different load center compartments (swapped). Designated personnel are not trained in performing this task.

- PIP O-02-6974, Unit 1 Borated Water Storage Tank heater failure alarms occurring at a high rate, with five request for repairs in a two week period, this could result in crystallization of the boron in the system.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions

a. Inspection Scope

The inspectors reviewed, the operating crew's performance during selected non-routine events and/or transient operations to determine if the response was appropriate to the event. In addition, operator response after reactor trips that required more than routine expected operator responses, or which involved operator errors was reviewed. As appropriate, 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. The non-routine evolutions reviewed during this inspection period included the following:

- On October 2, 2002, the operators detected an increase in the unidentified leakage rate from the Unit 1 reactor coolant system. The increased leakage was traced to a relief valve in the chemical sampling system

- Unit 3 reactor trip due to a main turbine trip, on November 14, 2002, caused by high water level in the moister separator reheaters

- Unit 3 reactor startup and power escalation following the reactor trip

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

Quarterly Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations affecting the risk significant mitigating 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 Limited Condition Operations. The inspectors reviewed the following items for operability evaluations:

- PIP O-02-5203, Operability of control batteries with room temperatures greater than 80 degrees F

- PIPs O-02-5215, 02-4570, 02-1569, and 00-2088, Operability of the ESV pumps, affecting all units, when leaking valves are discovered in the SSW system, thus diverting sealing/cooling water from the vacuum pumps

- PIP O-02-5263, Operability of the 1A LPI pump when a motor lead lug broke during the installation of the motor

- PIP O-02-5306, Operability of the Units 1 and 2 turbine driven emergency feed water pumps when water was found in the lube oil system

- PIPs O-02-5455 and 5494, Flow on the A and B outside air booster fans for Unit 1 and 2 control room did not meet acceptance criteria

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed selected operator workarounds to determine if the functional capability of the system or the human reliability in responding to an initiating event were affected. The inspectors specifically evaluated the cumulative effect of the operator workarounds on the ability to implement abnormal or emergency operating procedures. The inspectors also reviewed the workarounds that if not performed properly could result in a significant impact on the unit. The following items were included in this review:

- PIP O-02-4778, a relay in the 4160V circuit breakers could stick and prevent various safety related breakers from closing on demand. This was experienced on one breaker and is believed to be caused by a manufacturing varnish application problem. The operator workaround action is to take voltage readings and manually reset the relay if needed. The licensee has completed inspections and replacement of potential problem relays on Units 1 and 2 and plans on completing inspections and replacements of relays on Unit 3 during the spring 2003 refueling outage.

- PIPs O-01-3007, O-01-4856, and O-02-6905, The main turbine overspeed trip circuitry on Units 1 and 2 do not reset occasionally in a timely manner during testing. The reset must be held in place for up to 14 minutes. If this is not performed properly a main turbine trip could occur resulting in a reactor trip.

- PIPs O-02-6907 and O-02-6921, Valve 2V-18, Unit 2 upper surge tank (UST) dome to main condenser, was discovered closed. The lineup places a vacuum on the UST and provides deaeration to the condensate water. A work around procedure, OP/1&2/1106/16, Condensate Vacuum System, Enclosure 4.21, was written to open the valve. If this had not been performed properly a loss of main condenser vacuum would have occurred, causing a main turbine trip, and resulting in a reactor trip.

- PIP O-00-1590, Unit 3 steam generators must be manually isolated during a high energy line break (HELB), due to the automatic feedwater isolation system not being installed. If this is not performed properly a depressurization and overcooling of the reactor coolant system could occur affecting the mitigation of a HELB.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

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

- OP/0/A/2000/41, KHS - Modes of Operation, Revision 24, and MP/2/A/2200/03, KHU-2 Governor Actuator System Inspection and Maintenance, Revision 10, PMT for WO 9852379, isolate, disassemble, inspect, adjust, test, and restore

KHS Unit 2 governor actuator

- PT/3/A/0600/12, Turbine Driven Emergency Feedwater Pump Test, Revision 59, PMT for WO 98520939

- PT/1&2/A/0170/03, Control Room Ventilation System Operational Test, Revision 11, PMT for WR 98256608

- PT/0/A/0600/21, Safe Shutdown Facility Diesel/Generator Operational Test, Revision 09, PMT for WR 98542613

- PT/0/A/0251/29, Siphon Seal Water System Test, Revision 13, PMT for WO 98534656

- TT/2/A/0610/32, Verification of Breaker E2-2 Auxiliary Contact Repair, Revision 0

b. Findings

No findings of significance were identified.

1R20 Unit Outages

.1 Unit 2 Refueling Outage

a. Inspection Scope

The inspectors conducted reviews and observations for selected licensee 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 12, and November 25, the following activities related to the Unit 2 EOC19 refueling outage were reviewed for conformance to the applicable procedure and selected activities associated with each evaluation were witnessed:

- Reactor shutdown

- Mode changes from Mode 1, Power Operation, to Mode 6, Refueling

- Reduced inventory and mid-loop conditions for installation and removal of steam generator nozzle dams

- Defueling operations

- Defueled (no MODE) activities

- Refueling operations

- Activities involving the reactor vessel head control rod drive nozzles repairs

- Reactor startup and physics testing
- Mode changes from Mode 6, Refueling, to Mode 1, Power Operation
- System lineups during major outage activities and Mode changes

b. Findings

No findings of significance were identified.

.2 Unit 3 Forced Outage

a. Inspection Scope

Between November 14, 2002, and November 18, 2002, the following activities related to the Unit 3 reactor trip and the forced outage were reviewed for conformance to the applicable procedures and TS requirements. The inspectors witnessed selected activities associated with each evaluation.

- The evaluation of the post trip review team in determining the cause of the reactor trip
- The performance of the post trip recovery team and the repair activities
- Reactor startup and power escalation

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

.1 Routine Surveillance Testing Observations

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of the selected risk-significant SSCs listed below, to assess, as appropriate, whether the SSCs met TS, 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/0203/06AB, 3B Low Pressure Injection Pump Test - Recirculation, Revision 71
- PT/1/A/0202/11, 1C High Pressure Injection Pump Test, Revision 70
- PT/2/A/0610/01J, Emergency Power Switching Logic Functional Test, Revision 26

- PT/2/A/0251/24, High Pressure Service Water Full Flow Test, Revision 15

- PT/0/A/0811/01, Power Escalation Test, Revision 31

- PT/0/A/0205/05, Thermal Power and Reactor Coolant Flow Calculations, Revision 26

b. Findings

No findings of significance were identified.

.2 Surveillance Testing of Keowee Overhead

a. Inspection Scope

The inspectors reviewed the circumstances surrounding a missed Technical Specification required surveillance involving the Keowee Hydro Station overhead power path.

b. Findings

Introduction: A Green NCV of TS surveillance requirements (SR) 3.3.19.1, Channel Functional Test for Degraded Grid Voltage Protection Actuation Logic Channels, SR 3.8.1.15, 230kV Circuit Breaker Actuation on Switchyard Isolation, and TS 5.5.18, Keowee Hydo Unit (KHU) Commercial Power Generation Testing Program, was identified when it was discovered that PT/0/A/610/022, Keowee Over Frequency Protection Functional Test, was not performed within the required TS SR frequency.

Description: The missed functional test was inadvertently discovered by the licensee on December 31, 2002, while reviewing options of rescheduling the surveillance for a later date. Accordingly this issue is being treated as a self-revealing. The required frequency of the aforementioned TS surveillances is 18 months. As they were last performed in October 2000, their required frequency was exceeded. The licensee's investigation determined the cause of this missed surveillance to be an inadequacy in the work planning program.

The licensee implemented Surveillance Requirement Applicability, SR 3.0.3, and initiated a risk evaluation. The licensee concluded that the risk of continued operation for this condition to be yellow. The licensee managed this risk condition until January 4, 2003, at which time the functional test was successfully performed.

Analysis: The Keowee Hydro Units are required to provide emergency power to the site under various accident conditions. The missed surveillance's were required to verify operability of the units. The subsequent successful performance of PT/0/A/610/022 on January 4, 2002, verified that operability was maintained and that no unavailability of the Keowee Hydro Units was incurred. This finding was determined to be of very low safety significance as the SDP phase 1 screening of this issue was Green. This was based on the fact that there was no unavailability of the units resulting from the missed surveillances.

Enforcement: Technical Specification SR 3.3.19.1, Channel Functional Test for Degraded Grid Voltage Protection Actuation Logic Channels, SR 3.8.1.15, 230kV Circuit Breaker Actuation on Switchyard Isolation, and TS 5.5.18, KHU Commercial Power Generation Testing Program requires that PT/0/A/610/022, Keowee Over Frequency Protection Functional Test, be performed every 18 months. Contrary to the above, the licencee failed to perform PT/0/A/610/022 within the required frequency. Because the finding is of very low safety significance (Green) and is captured in the licensee's corrective action program as PIP O-02-07368, it is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. Accordingly, it is identified as NCV 50-269,270,287/02-05-04: Failure to Perform Surveillance within the Required Periodicity.

2. RADIATION SAFETY

Cornerstones: Occupational Radiation Safety and Public Radiation Safety

2OS1 Access Controls To Radiologically Significant Areas

.1 Access Controls

a. Inspection Scope

Licensee program activities for monitoring workers and controlling their access to radiologically significant areas and tasks were evaluated. The inspectors assessed adequacy of procedural guidance; directly observed implementation of administrative and established physical controls; and assessed resultant worker exposures to radiation and radioactive material. Radiation worker and Health Physics Technician (HPT) proficiency in implementing Radiation Protection (RP) program activities were appraised.

During the onsite inspection, access controls and monitoring of occupational exposures associated with Unit 2 reactor building scaffolding removal, basement floor sealing, in-service-inspection activities, and steam generator replacement preparatory work were observed, discussed, and evaluated. The evaluations included, as applicable, Radiation Work Permit (RWP) details; use and placement of dosimetry to monitor occupational exposures involving significant dose rate gradients; and electronic alarming dosimetry (EAD) set-points and use in loud noise areas. Effectiveness of established controls were assessed against area radiation and contamination survey results, potential for transient elevated dose rates, and occupational doses received. In addition, physical and administrative controls and their implementation for high radiation area (HRA), extra high radiation area (EHRA), and Very High Radiation Area (VHRA) entries and for storage of highly activated material within the spent fuel pool (SFP) were evaluated through direct observations of selected facility areas or job tasks, interviews of Health Physics technician and supervisory staff, and reviews of current survey records. The inspectors directly observed posting and controls for selected auxiliary building HRA/EHRA locations; posting and controls for Unit 2 Containment VHRAs; and material conditions and postings for waste processing and storage facilities. The inspectors observed radiation dose rates measured by an HPT and evaluated established posting and access controls for six elevations within the Unit 2 containment building.

Occupational workers' adherence to selected RWPs and HPT proficiency in providing job coverage were evaluated through direct observations, review of selected exposure records and investigations, and interviews with licensee staff.

Occupational exposure data associated with direct radiation, potential radioactive material intakes, and from dispersed facial contamination events during the current Unit 2 Refueling Outage were reviewed and assessed independently.

Radiation protection program activities and their implementation were evaluated against Title 10 Code of Federal Regulations (10 CFR) 19.12; 10 CFR 20, Subparts B, C, F, G, H, and J; UFSAR Section 11, Radioactive Waste Management, and Section 12, Radiation Protection; TS Sections 5.4 Procedures, 5.5 Programs and Manuals, and 5.6 Reporting Requirements; and approved licensee procedures. Licensee guidance documents, records, and data reviewed within this inspection area are listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

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 responsible licensee representatives. The inspectors assessed the licensee's ability to characterize, prioritize, and resolve the identified issues in accordance with licensee procedure Nuclear System Directive 208, Problem Investigation Process, Revision 12.

Specific assessments, audits, and PIPs reviewed and evaluated in detail for this inspection area are listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.3 Independent Spent Fuel Storage Installation (ISFSI)

a. Inspection Scope

Access control and surveillance results for the licensee's ISFSI were evaluated. The evaluation included review of ISFSI radiation control surveillance procedures and assessment of radiological survey data. The inspectors toured the ISFSI and observed access controls, thermoluminescent dosimeter (TLD) placement, and radiological postings on the perimeter security fence. The inspectors observed a licensee technician perform gamma and neutron radiation surveys of a spent-fuel cask. Surveys made at locations procedurally designated for routine surveys within the perimeter fence were also observed. Survey results were compared to the most recent survey records.

Program guidance, access controls, postings, equipment material condition and surveillance data results were reviewed against applicable sections of the cask Certificate of Compliance, Safety Analysis Report (SAR), ISFSI TS, 10 CFR Parts 20 and 72, and applicable licensee procedures. Licensee guidance documents, records, and data reviewed within this inspection area are listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment

.1 Area Radiation Monitoring and Post-Accident Sampling Systems

a. Inspection Scope

The availability, reliability, and operation of selected direct area radiation monitor (ARM) and continuous air monitor (CAM) equipment used for routine and accident monitoring activities were reviewed and evaluated. The inspectors reviewed Maintenance Rule evaluation data and directly observed equipment material condition, installed configurations (where accessible), and conduct of performance checks for selected monitors. Procedurally established alarm set-points were corroborated and performance check details were reviewed for selected ARM equipment through discussions and direct observation of Control Room instrumentation panel operations, settings, and monitor response readouts. Recent calibration data for five ARMs (listed in the Attachment at the end of this report) were reviewed and discussed with the responsible staff.

The inspectors evaluated Post-Accident Sampling System (PASS) equipment procedural guidance, operations, and equipment availability. The evaluation included review of current program guidance, assessment of recent surveillance tests, and status of Post Accident Gaseous and Liquid sampling system equipment/instrumentation availability and operability, and review of completed training for personnel.

Program guidance, performance activities, and equipment material condition for the direct radiation detection instrumentation and continuous air sampling equipment were reviewed against details documented in TS Section 5.4.1, Procedures; 10 CFR Parts 20 and 50, UFSAR Section 11, and associated licensee procedures. Program guidance, and radiation detection and sampling equipment required for accident monitoring were reviewed against TS Section 5.5.4, Post-Accident Sampling; applicable sections of NUREG-0737, Clarification of Three Mile Island (TMI) Action Plan Requirements, November 1980; and Regulatory Guide (RG) 1.97, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Rev. 3. Licensee guidance documents, records, and data reviewed within this inspection area listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.2 Personnel Survey Instrumentation

a. Inspection Scope

Current program guidance, including calibration and operation procedures, and its implementation to maintain operability and accuracy of selected fixed and portable survey instruments were reviewed and evaluated.

During the week of November 4, 2002, the inspectors reviewed current calibration data for selected personnel survey instruments and assessed operability of various portable survey instruments either staged for use or being used by the HPT staff. Instrument selection and operability determinations conducted by HPTs prior to performing selected radiological survey and/or monitoring activities were reviewed and discussed. The technical and HPT staff's knowledge and proficiency regarding instrumentation use and calibration activities were evaluated through interviews, record reviews, and direct observation of radiation and contamination surveys. Actions taken for portable survey instruments found to be significantly outside of acceptance criteria during routine calibration activities were reviewed and discussed with responsible licensee representatives.

Operability and analysis capabilities of the whole body counting (WBC) equipment for monitoring internally deposited radionuclides and for Personnel Contamination Monitor (PCM) equipment utilized for surveys of individuals exiting the radiologically controlled area (RCA) were evaluated. For both WBC and PCM equipment, current calibration and recent operational/performance test surveillance data, as applicable, were evaluated. The licensee's data base of radionuclides used for routine and investigative WBC analyses were reviewed and evaluated. Selected WBC data analysis results were reviewed and discussed with responsible staff to assess knowledge and proficiency in evaluating results and resolving unknown energy peaks. The inspectors directly observed conduct of PMC surveillance tests for selected instrumentation located at Radiologically Controlled Area (RCA) egress control points. In addition, selected PCM detector responses to a National Institute of Standards and Technology (NIST) traceable Cesium (Cs)-137 source, source strength of approximately 5000 disintegrations per minute per 100 square centimeters (dpm/100 cm^2), were observed and discussed with licensee representatives.

Licensee activities associated with personnel radiation monitoring instrumentation were reviewed against TS 5.4.1 Procedures; 10 CFR 20.1204 and 20.1501; and applicable licensee procedures listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.3 Respiratory Protection - Self-Contained Breathing Apparatus (SCBA)

a. Inspection Scope

The licensee's respiratory protection program guidance and its implementation for SCBA equipment use were evaluated. The number of available SCBA units and their general material and operating condition were observed during tours of the Unit 1& Unit 2 Control Room common area, the Unit 3 Control Room area, and Operations Support Center. Current records associated with supplied air quality, and maintenance activities for staged SCBA equipment were reviewed and discussed. Proficiency and knowledge of staff responsible for maintaining SCBA equipment were evaluated through review of training certificates, and from discussions and demonstration of an SCBA monthly functional test. The inspectors reviewed records and evaluated status of medical qualifications, fit test results, and training status for Emergency Response Organization personnel on-call during the week of November 4, 2002. In addition, Control Room operations staff were interviewed to determine their level of knowledge of available SCBA equipment storage locations, selection of respirators and proper use, bottle change-out, and availability of prescription lens inserts, if required.

Licensee activities associated with maintenance and use of SCBA equipment were reviewed against TS Section 5.4.1, Procedures; 10 CFR Part 20.1703; FSAR Section 12; RG 8.15, Acceptable Programs for Respiratory Protection, Rev. 1, October 1999; American National Standards Institute (ANSI)-Z88.2-1992, American National Standard Practices for Respiratory Protection; and applicable licensee procedures listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.4 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed selected PIP issues associated with area radiation monitoring equipment, portable radiation detection instrumentation, and respiratory protective program activities. The inspectors assessed the licensee's ability to characterize, prioritize, and resolve the identified issues in accordance with licensee procedure Nuclear System Directive 208, Problem Investigative Process, Rev. 12.

Specific documents reviewed and evaluated are listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

.1 Effluent Processing and Monitoring Systems Reviews

a. Inspection Scope

The operability, availability, and reliability of selected effluent process sampling and detection equipment used for routine and accident monitoring activities were reviewed and evaluated. Inspection activities included record reviews and direct observation of equipment configuration and operation. The following effluent monitoring equipment was included in the inspection:

- Unit 3 Radiation Indicating Alarm-32 (3RIA-32), Auxiliary Building Gas Monitor
- RIA-33, Liquid Radwaste Effluent Monitor
- 3RIA-37, Waste Gas Effluent Monitor
- 2RIA-43, Unit Vent Particulate Monitor
- 2RIA-44, Unit Vent Iodine Monitor
- 2RIA-45, Unit Vent Gas Monitor

For a Decant Monitor Tank release conducted on November 6, 2002, the inspectors directly observed process effluent sampling and monitoring equipment material condition, installed configurations (where accessible), and operability; evaluated local and control room data regarding flow rates and channel response checks; and reviewed and evaluated established effluent release set-points. The inspectors assessed sample representativeness, radionuclide concentration sensitivities, achieved analyses accuracies, pre-release dose calculation completeness, and adequacy of effluent radiation monitor set-point determinations. Technician proficiency in conducting pre-release processing, sampling, and gamma spectroscopy analyses was observed and evaluated. Interviews were conducted with two chemistry technicians to evaluate staff proficiency and knowledge of effluent release requirements, equipment capabilities, and procedural details.

The licensee’s laboratory quality control (QC) program activities for liquid and airborne sample radionuclide analyses were evaluated. The inspectors discussed and reviewed, as applicable, laboratory QC activities including current gamma spectroscopy and liquid scintillation detection equipment calibrations, calibration source details; and daily system performance results; preparation, processing and storage of composite samples; radionuclide lower limit of detection (LLD) capabilities and achieved accuracies; and results of the quarterly cross-check spiked radionuclide samples analyzed during calendar year (CY) 2001 and year-to-date (YTD) 2002.

Program guidance, equipment configuration and material condition for the effluent sampling and monitoring equipment were reviewed against details documented in TS Sections 5.4, 5.5, and 5.6; 10 CFR Part 20, UFSAR Sections 11, 12, and 16 Selected Licensee Commitments; Offsite Dose Calculation Manual (ODCM), Rev. 42; ANSI-N13.1-1969, Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities; ANSI-N13.10-1974, ANS Specification and Performance of On-Site Instrumentation for Continuously Monitoring Radioactivity in Effluents, and approved procedures listed in the Attachment at the end of this report.

In-place liquid effluent release equipment, observed task evolutions, and offsite dose results were evaluated against 10 CFR Part 20 requirements; Appendix I to 10 CFR Part 50 design criteria: TS Sections 5.4, 5.5, and 5.6; UFSAR Sections 11 and 16 details, ODCM Rev. 42 specifications; and applicable procedures listed in the Attachment, Laboratory and sample processing QC activities were evaluated against RG 1.21, Measuring, Evaluating and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials In Liquid and Gaseous Effluents from Light-Water Cooled Nuclear Power Plant, June 1974; and RG 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operation) - Effluent Streams and the Environment, December 1977.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

Licensee PIP issues documented for effluent processing and monitoring activities were reviewed. The inspectors assessed the licensee's ability to characterize, prioritize, and resolve the identified issues in accordance with licensee procedure Nuclear System Directive 208, Rev.12. Four PIPs (listed in the Attachment at the end of this report) were reviewed and evaluated in detail.

b. Findings

No findings of significance were identified.

2PS3 Radiological Environmental Monitoring Program (REMP) and Radioactive Material Control Program

.1 REMP Implementation

a. Inspection Scope

The licensee's 2001 Annual Radiological Environmental Operating Report was reviewed and discussed with licensee representatives. The inspectors assessed data analyses, surveillance results, and land-use census information. Report details were evaluated for required sample types, sampling locations, and monitoring frequencies.

During the week of November 4, 2002, the inspectors toured and evaluated selected sampling stations for location and material condition of REMP equipment. Collection of air particulate filters and charcoal cartridges and determinations of flow rates were inspected at air sampling stations 79 and 81. The inspector also observed the collection of broadleaf vegetation samples at those two sites. Collection of dairy samples was reviewed at sampling location 82. The proficiency and knowledge of technicians collecting the samples and the adequacy of collection techniques were assessed. The placement and material condition of TLDs were evaluated at monitoring sites 22, 23, 44, 56, and 81. Using Global Positioning System equipment, the inspectors independently determined the locations of the seven REMP sites listed above and compared the results to the locations documented by the licensee in the Annual Radiological Environmental Operating Report.

Program guidance, procedural implementation, and environmental monitoring results were reviewed against Section 16.11.6 of the Selected Licensee Commitments (SLC) Manual; 10 CFR Parts 20 and Appendix I to 10 CFR Part 50 design criteria requirements; UFSAR details; ODCM guidance; and applicable procedures listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.2 Meteorological Monitoring Program

a. Inspection Scope

Licensee program activities to assure accuracy and availability of meteorological data were evaluated. The inspectors reviewed and evaluated data obtained from the primary and backup meteorological towers. During the week of November 4, 2002, the inspectors toured primary and backup meteorological facilities, assessed equipment material condition, and reviewed instrument operability. The consistency of current meteorological data between the local readout at the primary meteorological tower and the in-plant data from the Operational Aid Computer (OAC) was analyzed. Meteorological data recovery reports for 2001 and 2002 were evaluated. In addition, the inspectors compared 2001 meteorological monitoring data against licensee assumptions used for effluent releases and assessments.

Meteorological program implementation and activities were reviewed against 10 CFR Part 20; SLC Manual; UFSAR Section 2.3; ODCM guidance; and applicable procedures listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.3 Unrestricted Release of Materials from the RCA

a. Inspection Scope

Radiation protection program activities associated with the unconditional release of materials from the RCA were reviewed and evaluated. The inspectors compared current calibration and performance check source radionuclide composition to radionuclides identified in current dry active waste (DAW) stream 10 CFR Part 61.55 analyses. Current calibration and performance check data were reviewed and discussed with responsible licensee representatives and the inspectors directly observed surveys of materials released from the RCA using Small Article Monitor (SAM) equipment. In addition, SAM-9 and SAM-11 equipment sensitivities were assessed using a low-level NIST traceable Cs-137 radioactive source, i.e., source strength of approximately 5000 dpm/100 cm^2, and placement at varying locations within the detection equipment.

The licensee practices and implementation of monitoring for unconditional release of materials from the RCA were evaluated against 10 CFR Part 20; TS 5.5; UFSAR Section12; and applicable licensee procedures. The applicable licensee guidance, calibration records, and performance data are listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

.4 Problem Identification and Resolution

a. Inspection Scope

Licensee audits and PIPs associated with REMP operations and with program activities associated with unrestricted release of materials from the RCA were reviewed and evaluated. Specific PIPs reviewed and evaluated in detail are listed in the Attachment at the end of this report. The inspectors assessed the licensee’s ability to characterize, prioritize, and resolve the identified issues in accordance with licensee procedure Nuclear System Directive 208, Problem Investigative Process, Rev. 12.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Occupational Radiation Safety PI Verification

a. Inspection Scope

The licensee's Occupational Exposure Control Effectiveness PI results for the Occupational Radiation Safety Cornerstone were reviewed for the period October 1, 2001 through September 30, 2002. For the subject period, the inspectors reviewed data reported to the NRC, and sampled and evaluated applicable corrective action program issues and selected Health Physics Program records. The inspectors assessed the licensee monthly review for PI occurrences as performed for December 2001 through September 2002 in accordance with Procedure SH/0/B/2002/001. The licensee's disposition of the reviewed issues was evaluated against NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 2.

b. Findings

No findings of significance were identified.

.2 Public Radiation Safety PI Verification

a. Inspection Scope

The inspectors reviewed and discussed the Radiological Control Effluent Release Occurrence PI results for the Public Radiation Safety Cornerstone from October 1, 2001, through September 30, 2002. For the subject period, the inspectors reviewed data reported to the NRC, and sampled and evaluated applicable corrective action program issues and selected Health Physics Program records. The inspectors assessed the licensee monthly review for PI occurrences as performed for December 2001, through September 2002 in accordance with Procedure SH/0/B/2002/001. The licensee's disposition of the reviewed issues was evaluated against NEI 99-02, Revision 2.

b. Findings

No findings of significance were identified.

.3 Initiating Events, and Barrier Integrity Cornerstones

a. Inspection Scope

The inspectors conducted annual reviews of the Oconee Units 1, 2, and 3 PIs listed in the table below, to determine their accuracy and completeness against requirements in NEI 99-02, Revision 2.

Cornerstone: Mitigating Systems		
Performance Indicator	*Verification Period*	*Records Reviewed*
Safety System Unavailability for the Residual Heat Removal System (all Units)	1 st quarter, 2002, 2 nd quarter, 2002 and 3rd quarter, 2002	• Problem Reports (PIPs) • Monthly Operating Reports • operator logs
Safety system Unavailability for the High Pressure Injection System (all Units)		
Safety System Unavailability for the Heat Removal System (Emergency Feedwater) (all Units) Safety System Unavailability for the Emergency AC Power System Safety System Functional Failures (all Units)		

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Annual Sample Review - Uncontrolled Design Change to the Feedwater Pipe Whip Restraints

a. Inspection Scope

The inspectors performed an in-depth review of the Unit 2 feedwater pipe whip restraint design requirements in order to verify proper implementation and to determine if deviations were being properly identified and documented in the licensee's corrective action program. Following the field inspections, the inspectors verified that conditions adverse to quality were properly documented in the licensee's corrective action program.

b. Findings

Introduction

The inspectors identified that clearances between the Unit 2 feedwater pipe whip restraint nuts and structural mounting plates were not in accordance with the gap requirements specified in the design drawing. The consequences of not maintaining the specified gap between these components is currently under review and is identified as an unresolved item (URI).

Description

The two feedwater lines for each Oconee unit enter containment from the east penetration room. Each feedwater line has a rupture whip restraint which is attached to the piping and is adjacent to the containment penetration. The restraint is located between the containment penetration and the feedwater line check valve. The restraint has eight threaded rods, with each rod being pinned on one end to the support structure and the other end being connected by a nut to a mounting plate that is welded to the feedwater piping. Note (7) on Design Drawing O-494 specifies that final tightening of the nuts shall be performed when the feedwater piping is at normal operating temperature (465 degrees F). The note continues to indicate that the nuts shall be drawn snug, then backed off one-quarter turn. Rod threads shall then be jammed to prevent rotation of the nuts. In earlier discussions with the licensee, the inspectors had been informed that during shutdown conditions, with the feedwater system at ambient (cold) temperature, a gap of 1/8-1/10 of an inch should exist between each whip restraint nut and its associated mounting plate.

During the fall 2002 (EOC 19) Unit 2 refueling outage, the inspectors inspected the Unit 2 feedwater pipe whip restraints while at ambient temperature. For the restraint associated with feedwater penetration 25, the inspectors found that no gap existed for six of the eight nuts. The licensee had to use a wrench to loosen these nuts. The remaining two nuts could be loosened by hand; however, the inspectors noted that there was no visual indication of any gap. For the restraint associated with penetration 27, five of the eight nuts could be loosened by hand; however, the inspectors noted that there was no visual indication of any gap. In addition, it was noted that the licensee did not attempt to measure any of the gaps. The remaining three nuts were covered by asbestos insulation and the licensee elected not to remove the insulation and inspect them. The licensee subsequently adjusted the nuts to provide gaps at ambient conditions.

The inspectors noted that the feedwater whip restraints were installed in response to the "Giambusso Letter" of December 1972, which implemented 10 CFR 50 General Design Criteria (GDC)- 4. This letter required the licensee to analyze and to protect the plant from piping breaks at the terminal ends of high energy piping. Per Branch Technical Position MEB 3.1, terminal ends are defined as "Extremities of piping runs that connect to structures, components, or pipe anchors that act as rigid restraints to piping motion and thermal expansion." The design of the feedwater line whip restraint is such that the stationary end of the restraint (feedwater piping welded to support) is a terminal end, which is enclosed by the remainder of the whip restraint. In theory, if a pipe break were to occur, the location would be at the terminal end and the whip restraint would restrict movement of the piping and prevent excessive damage to nearby components and systems. Because the feedwater pipe restraint nuts were tightened when the feedwater system was at ambient conditions, the inspectors concluded that the restraints could have acted as rigid restraints to piping motion during normal (hot) conditions and caused a partial moment restraint similar to that created by a pipe anchor. As a consequence, the whip restraint created local stresses similar to the local stress created by a terminal end at a pipe location that is not protected by a whip restraint. Based on this change, the feedwater pipe whip restraint may not have been capable of mitigating the effects of a pipe break at a terminal end.

In response to these as-found conditions, the licensee performed an engineering evaluation and documented the results in a position paper. The inspectors, along with NRC Regional and Nuclear Reactor Regulation (NRR) engineering personnel reviewed the evaluation. The licensee concluded that the location of the terminal end had not changed. They stated that if the nuts had been overly tightened and if the maximum thermal expansion differences between the feedwater piping and restraint actually existed, the whip restraint would experience "enormous loads" such that component damage would have been obvious. The various types of damage mentioned included failure of the clevises that connect the rods to the stationary part of the restraint, failure of the mounting plate, and deformation of the rod threads. The licensee stated that no damage was noted that would indicate a bound condition had existed. The inspectors noted no damage to the restraint or piping during their inspection. The inspectors and appropriate NRC engineering personnel are continuing to review and discuss with the licensee their evaluation and conclusion that the lack of clearances for the feedwater piping restraints did not adversely impact the feedwater system.

<u>Analysis:</u> The inspectors are continuing to review and assess the potential impact of an unrestrained feedwater piping break in the east penetration room. The inspectors noted that feedwater pipe whip following a pipe break would damage safety-related piping and electrical components in the area. In addition, an unrestrained break in feedwater piping between the check valve and SG would cause the amount of escaping steam flow to exceed the analyzed amount and may exceed the pressure rating of structures. The full extent of possible damage from a change in the location of the terminal end has not been fully assessed.

<u>Enforcement:</u> 10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawing, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. The design drawing requirements for feedwater piping restraint clearances were not met. Final disposition of this issue is pending determination of the consequences for not maintaining the clearances and any corresponding increase in plant risk. This issue is identified as URI 50-270/02-05-05: Determination of Consequences for not Maintaining Design Clearances on Feedwater Piping Restraints and Corresponding Risk.

.2 <u>Cross-Reference to PI&R Findings</u>

Sections 1R08.2,1 R12.2, and 4OA7 describe findings for failure to take timely corrective action for conditions adverse to quality.

4OA3 Event Followup

.1 (Closed) LER 50-269/02-05-00: Potential Failure of Manual Atmospheric Dump Valve due to Pressure Locking

This LER involved the failure of Valve 1MS-156, one of two atmospheric dump valves on the 1B once through steam generator (OTSG), due to the potential for pressure locking. In November 1997, the licensee replaced the valve as a like-for-like replacement, when in fact it was not. The previous valve was a solid wedge gate valve, but the replacement was a flex wedge gate valve that was susceptible to pressure locking. The design function of 1MS-156 is to vent the OTSG at lower pressures, primarily to mitigate a steam generator tube rupture (SGTR). The process, as described in the basis for TS 3.7.4, would be for the operators to open the block valve bypass (1MS-163) to equalize pressure, and then open block valve 1MS-155. The operators would then use the other atmospheric dump valve (1MS-164), which is a throttle valve, to control pressure until RCS temperature reaches approximately 363 degrees F. The operators would then open 1MS-156 to cool the RCS to LPI conditions. Without 1MS-156, the time to cool to LPI conditions would take longer and increase the amount of material released following the SGTR. The licensee identified that Valve 1MS-156 had been inoperable from November 28, 1997, until July 8, 2002. The licensee entered the valve into their corrective action program as PIP O-02-03626 and removed the pressure locking potential by installing a bonnet vent line.

The inspectors reviewed this LER against the Significance Determination of Reactor Inspection Findings for At-Power Situations. In doing this review the inspectors assumed that, following a SGTR, valve 1MS-156 would not be available to help cool the RCS to LPI conditions. Because both atmospheric dump valves need to be available for full mitigation credit in a SGTR, the inspectors assumed that an actual loss of the safety function of 1MS-156 had occurred. This would affect secondary heat removal and pressure equalization functions for STGR under the mitigating systems cornerstone. Both the Phase 2 screening and the Phase 3 large early release frequency review indicated a very low safety significance (Green) based on maintaining system function through the other ADV. Accordingly, this issue has been recognized as a licensee identified NCV in Section 4OA7 below.

.2 (Closed) LER 50-270/02-01-00: Technical Specification Valve Manually (ADV) Inoperable Due To Mechanical Interference

This LER was addressed in Section 1R12.1, and is considered closed.

.3 (Closed) LER 50-269/01-S01-00: Security Access Revoked for Falsification of Criminal Record

This LER addressed the licensee’s granting of unescorted access to the protected area to a vendor employee during the period March 3, 1999, through June 7, 1999, based on inaccurate criminal history information entered into the Plant Access Data System (PADS) by another licensee. PADS is widely used database which allows sharing of background screening data among nuclear sites. On April 10, 2001, Oconee became aware that the another licensee failed to update PADS to reflect criminal history information developed during its background investigation process of the applicant which had not been reported by the applicant on his background investigation questionnaire (BIQ). Based on a review of information in the LER submitted by the licensee who failed to update PADS in this case, the chronology of events at Oconee concerning the individual who was granted access based on the incorrect PADS information, and Duke Power's Access Authorization Procedure, NSD-218, Revision 7, the inspectors concluded that the licensee followed their access authorization process for granting unescorted protected area access at Oconee and took appropriate actions upon being notified by the other licensee of the BIQ falsification. Based on the review of available information, no findings of significance or violations of regulatory requirements were identified related to Oconee.

.4 (Closed) LER 50-270/02-02-00: Unit 2 Reactor Coolant System Pressure Boundary Leakage due to Cracks Found in Reactor Vessel Head Penetrations

The reported condition involved masked or leaking CRDM nozzles on Unit 2. The leaks were determined to have resulted from cracks predominately due to primary water stress corrosion cracking (PWSCC), which had initiated in the weld material. The licensee captured this issue in their corrective action program as PIP O-02-05496. Repairs to the reactor head penetrations were completed prior to restart from the outage.

As indicated in Section 4OA7 of this report, this event constituted a violation of NRC requirements, as the leakage was a violation of Oconee TS 3.4.13 which states that reactor coolant system (RCS) operational leakage shall be limited to no pressure boundary leakage. Detailed in Section 4OA5.3 below, this finding was of very low safety significance (Green) because it is reasonable to assume no loss of function of the RCS boundary and to expect the structural integrity of the RCS to be maintained. An important factor influencing the significance was the very low likelihood of the initiating event (LOCA) resulting from cracks in the CRDM nozzle J-Welds. No other findings or issues of significance were identified.

4OA5 Other

.1 Temporary Instruction (TI) 2515/148, Appendix A, Pre-inspection Audit for Interim Compensatory Measures (ICMs) at Nuclear Power Plants

a. Inspection Scope

The inspectors conducted an audit of the licensee's actions in response to a February 25, 2002, Order which required the licensee to implement certain interim security compensatory measures. The audit consisted of a broad-scope review of the licensee's actions in response to the Order in the areas of operations, security, emergency preparedness, and information technology as well as additional elements prescribed by the TI. The inspectors selectively reviewed relevant documentation and procedures; directly observed equipment, personnel, and activities in progress; and discussed licensee actions with personnel responsible for development and implementation of the ICM actions.

The licensee's activities were reviewed against the requirements of the February 25, 2002 Order; the provisions of TI 2515/148, Appendix A; the licensee's response to the Order; and the provisions of the NRC-endorsed NEI Implementation Guidance, dated July 24, 2002.

b. Findings

No findings of significance were identified. A more in-depth review of the licensee's implementation of the February 25, 2002, Order utilizing Appendix B and C of TI 2515/148 will be conducted in the near future.

.2 (Closed) URI 50-269,270,287/2001-08-02: Steam Generator Tube Stresses Resulting from Use of the Station Auxiliary Service Water Tornado Pump

Due to the time necessary to evaluate alternate core cooling strategies and to place the ASW tornado pump into service, the compressive steam generator tube stresses exceeded manufacturer design limits on the tubes. An analysis did not exist that confirmed the integrity of the steam generators under these conditions. Through the licensee's corrective action system, a new compressive differential temperature limit was established, assuming ASW tornado pump operation at approximately 40 minutes after event initiation. This temperature limit is one component of the postulated steam generator tube differential stresses associated with this event. Using the new differential temperature, a steam generator structural analysis was undertaken. After the licensee completed this structural analysis, a technical reviewer in the Mechanical and Civil Engineering Branch of the Office of Nuclear Reactor Regulation performed an adequacy review of the analysis (Task Interface Agreement 2002-05). To this end the analysis documented as Calculation OSC-8055, "ONS Tornado Event Transients-OSTG Tube Allowable Flaw Size and Tube Integrity Under Axial Compression with Either Axial or Circumferential Tube Degradation," was reviewed. The review determined that the methodology was appropriate, and the analysis fundamentally sound. Consequently, the calculation supported the use of the Station ASW pump for secondary side heat removal within the 40 minute time constraint without structural damage to the steam generators. This analysis had always been required under 10 CFR 50, Appendix B, Criterion III, "Design Control." However, since its omission did not impact the operability, availability, reliability or the function of the steam generators, this violation is considered minor. Violations of minor significance are not subject to enforcement action as described by Section VI.A.1 of the NRC Enforcement Policy, NUREG-1600.

.3 (Closed - Oconee Unit 2 only) TI 2515/150: Reactor Pressure Vessel Head and Head Penetration Nozzles (NRC Bulletin 2002-02)

a. Inspection Scope

The inspectors observed activities relative to inspection of the reactor vessel head penetrations (VHPs) in response to NRC Bulletins 2001-01, 2002-01, and 2002-02. The guidelines for the inspection were provided in TI 2515/150, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02). The inspection included the review of NDE procedures, assessment of NDE personnel training and qualifications, observation and assessment of visual (VT), UT and PT examinations.

Discussions were also held with contractor and licensee personnel. Activities were examined to validate licensee conformance with inspection commitments and gather information to help the NRC staff identify possible further regulatory positions and generic communications.

Specifically, the inspectors reviewed or observed: (1) VT inspection using remote video of VHPs for leakage; (2) in-process UT examinations of reactor head penetrations (CRDMs, etc,) using the the remote automated "ACCUSONEX" data acquisition and analysis system to detect and characterize axial, circumferential and off-axis inner diameter (ID) and outer diameter (OD) initiating flaws in the nozzle base metal as well as leak paths in the interference fit region of the nozzle; (3) Rotating Probe UT of previously repaired nozzles; (4) PT data of selected RPV head J-groove welds; and (5) plant specific information (head temperature and exposure) to verify that the correct inputs were used in the time-at-temperature model for determining Unit 2 RPV head susceptibility ranking.

a. <u>Findings</u>

The licensee performed a qualified visual inspection for all RPV penetrations and identified wet leak indications on seven nozzles (Nos. 8, 9, 19, 24, 31 ,42 and 67) with five other nozzles identified as being 'masked' by dry boron deposits and therefore requiring further examination (Nos. 1, 4,18, 60, 63). In order to confirm nozzle integrity, the licensee also performed a UT examination on all 69 nozzles. Based on final UT, VT and PT results, the licensee identified indications in 15 nozzles (Nos. 1, 8, 9, 11, 15, 19, 21, 24, 31, 36, 38, 42, 60, 63 and 67) and repaired them all. The licensee characterized the cracks found in the nozzles as axial cracks either ID, OD, or weld, with 7 classified as wet thru wall leaks. The licensee dispositioned one nozzle as satisfactory (No. 56), when after grinding an identified indication, a final PT examination found no recordable crack indications on the weld.

The licensee captured this issue in their corrective action program as PIP O-02-05496**.** The leakage violated Oconee TS 3.4.13, which states that RCS operational leakage shall be limited to no pressure boundary leakage. As indicated in Section 4OA3.4 above, this event, which constituted a violation of NRC requirements, was reported in LER 50-270/02-02-00.

Specifically, the inspectors addressed the following TI elements:

(1) Inspector verification that the examinations were performed by qualified and knowledgeable personnel.

The inspectors found that visual and NDE inspections were being performed in accordance with approved and demonstrated procedures by trained and qualified inspection personnel. All examiners had significant experience, including previous experience inspecting and detecting flaws in VHPs.

(2) Verification that the examinations were performed in accordance with approved procedures.

Visual Examinations

The inspectors reviewed Procedure MP/0/A/1150/029, Reactor Vessel Head Penetrations - Visual Inspection. The licensee's examination plan included a visual examination from nine reactor head service structure inspection ports with the reactor head in place and the reactor coolant system at normal operating temperature and pressure. Any suspected leakage observed by the visual examination was to be further checked using NDE techniques. The inspectors verified by direct observation and in discussions with examination personnel that the approved acceptance criteria for head penetration leakage were applied in accordance with the procedure and also verified that the examination results for each penetration were individually documented. A second visual inspection was performed after the reactor head was placed on the head stand and boron deposits removed to identify any wastage masked by boron. A third visual inspection was performed after all 15 weld repairs were complete and another head wash was performed. The inspectors observed that the bare metal visual examinations were done per procedure. No reactor head wastage was identified during any of the 3 visual inspections.

The inspectors observed that some penetrations were hard to see from the inspection ports and that some of the previously repaired welds were masked with dry boron deposits. From this the inspectors questioned the licensee's ability to adequately examine these penetrations. In order to positively determine if penetrations were leaking, the licensee performed additional NDE on these penetrations.

UT and PT Examinations

No reactor vessel head wastage was identified during any of the bare metal visual inspections and to address potential RPV head penetration integrity issues all 69 nozzles received UT examination (including the 4 previously repaired nozzles) in accordance with Procedure 54-ISI-100-09. Equipment models, specifications, calibration and transducer frequencies were verified by the inspectors to be as stated in the qualification. The mechanized scans used blade and rotating probes, the circumferential blade probe was the primary inspection probe as it had been demonstrated for the detection of ID and OD surface connected circumferential, off-axis and axial flaws.

The UT (Aramis) inspection area for the 65 non-repaired nozzles from under the head using the circumferential blade probe to inspect for both axial and circumferential indications, extended from approximately 11" above the bottom of the nozzle and 370 degrees around the nozzle (10 degree overlap). Eleven special interest nozzles also received a second UT examination using the top-down rotating probe, with an inspection area from the bottom of the nozzle to the top of the head. Five nozzles had PT examinations performed of the surface of the J-groove weld and OD surface of the CRDM nozzle. The area of coverage for this PT was the nozzle OD extending below the head and the weld and cladding surface extending 3" radial out from the OD of the nozzle.

For the 4 previously repaired nozzles, the UT inspection area was the repair weld, the heat-effected zone under weld and ½" up into the tube using the rotating probe configured for inspection of the ID Temper bead repair. Two of the repaired nozzles also received a PT inspection, with the area of coverage ½" below the weld to approximately 2" above the weld.

The inspectors observed in-process examinations, reviewed the Framatome procedures and the licensee's inspection plan approved by Duke management for use for the VHP inspection. The inspectors noted that approved acceptance criteria and/or critical parameters for VHP leakage were applied in accordance with the procedures.

(3) Verification that the licensee was able to identify, disposition, and resolve deficiencies. Determine extent of material deficiencies (associated with the concerns identified in the bulletins) which were identified that required repair.

All nozzles received both a surface (VT or PT) and volumetric inspection (UT). If a VT surface inspection of a nozzle was not possible due to masking of the nozzle then an alternate PT surface inspection was performed. Indications considered to be potential crack indications from either inspection were required to be reported for further inspection and disposition. The licensee established a zero tolerance criteria, where any axial indications found in either of the UT or PT examinations, regardless of the presence or absence of an obvious axial leak path, would require the nozzle to be repaired. As a result, of the 69 penetrations inspected using VT, UT and in some cases PT examination, 15 nozzles were scheduled for repair, 7 due to identified thru wall wet leakage cracks and 8 due to the Oconee zero tolerance criteria as potential flaws had been identified.

No expansion-of-scope was required as 100% of the nozzles were inspected with a UT probe qualified to detect and characterize axial, circumferential, and off-axis ID and OD initiating flaws in the nozzle base metal as well as leak paths in the interference fit region of the nozzle. Inspectors noted that past repair techniques appeared to be validated as recordable flaws were not found in any of the 4 previously repaired nozzles. As a permanent corrective action resolution to the PWSCC vessel head cracking issue, the licensee had ordered new reactor heads for all three units and scheduled head replacement for the next refueling outage was actively underway (Unit 3 - April 2003, Unit 1 - Fall 2003, Unit 2 - Spring 2004).

The wet leaks and other identified cracks were determined to have resulted predominantly from PWSCC in the CRDM nozzle J-welds, and therefore this finding affected the Reactor Safety Cornerstone and the Initiating Events objective of limiting the likelihood of LOCAs. The finding was processed through the significance determination process Phase 1 and was determined to be of very low safety significance (Green). This was based on assumptions for this deficiency that there would have been no loss of function of the RCS pressure boundary and that it is reasonable to expect the structural integrity of the RCS to have been maintained. This is due to the fact that the cracks found in the CRDM welds have minimal potential to structurally fail in a manner that would allow a nozzle to be ejected. Although leakage through the welds creates an environment around the nozzle above the welds that could lead to circumferential cracking of the nozzle and potentially to nozzle ejection, inspection of nozzles by the licensee did not indicate circumferential cracking. Additionally, ejection of a nozzle due solely to a cracking of the weld itself is unlikely as the nozzle and attached remaining weld could not be forced through the tight bore of the head. Also considered were the extensive time to reach the critical crack length, the numerous licensee inspections that would take place allowing for identification and repair prior to reaching the critical crack length and the full compliment of emergency core cooling systems that are capable of protecting the core. Enforcement associated with this issue is discussed in Section 4OA7.

(4) Verification that the licensee was capable of identifying the PWSCC phenomenon described in the NRC bulletins.

The licensee performed NDE examinations on 100% of the CRDM nozzles during the outage. The inspection techniques used had been previously demonstrated capable of detecting PWSCC type cracks as well as cracks from actual samples from another unit. During the inspection, PWSCC cracks were identified and conservatively dispositioned. No unusual cracks or crack locations as compared to past inspections were found, most were typical PWSCC cracks found to have migrated from the toe of the weld up into the nozzle.

(5) Evaluate condition of the reactor vessel head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions).

The inspectors performed a direct observation of the Unit 2 reactor vessel head and noted that no significant examples of insulation, leakage sources, debris, dirt, impeded the examination. If the licensee was not able to adequately view each of the 69 CRDM nozzles and the reactor head vent nozzle during the VT surface examinations, then a PT surface examination was performed.

(6) Evaluate ability for small boron deposits, as described in Bulletin 2001-01, to be identified and characterized.

Three qualified bare metal inspections were performed. One inspection with the head still on the vessel to identify boron deposits; a second after the head was placed on the head stand and deposits removed to identify any wastage on nozzles masked by boron, and a third visual inspection after all repairs were completed and a second head wash performed. All nozzles initially masked by boron received a volumetric (UT) examination and an alternative type surface inspection (PT).

(7) Determine any significant items that could impede effective examinations.

No significant items that could impede the examination process were noted during observation of the visual or NDE examinations. All nozzles were 100% circumferential blade probe tested with the exception of 3 nozzles. For the 3 nozzles where only partial coverage was able to be obtained with the circumferential blade probe, two nozzles (95% and 80% coverage) were technically dispositioned as the small percentage of area not covered was not in the toe of the weld, and the third (20% coverage) received a second UT examination with the top down rotating probe configured for the inspection of tube material of non-repaired nozzles.

4OA6 Management Meetings

Exit Meeting

The inspectors presented the inspection results to Mr. Bruce Hamilton, Station Manager, and Mr. David Baxter, Manager of Engineering, and other members of licensee management at the conclusion of the inspection on January 14, 2003. 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 Violation

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements, which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs:

- TS 3.7.4, requires that the ADV flow path for each steam generator be operable, with 12 hours to be in Mode 3 if one or both paths are not operable. The basis for TS 3.7.4 indicated that Valve 1MS-156 was part of the ADV flow path (atmospheric vent block valve). Contrary to TS 3.7.4, Valve 1MS-156 was inoperable from November 28, 1997, until July 8, 2002, after being replaced with a valve that was susceptible to pressure locking. As discussed in detail in Section 4OA3.1, this licensee identified violation is of very low safety significance (Green) based on maintaining system function through the other ADV. The licensee entered the valve into their corrective action program as PIP O-02-03626 and removed the pressure locking potential by installing a bonnet vent line.

- On October 23, 2002, the licensee discovered four rags, each measuring one square foot, in the Unit 2 UST. The UST is the primary source of water for the motor and the turbine driven emergency feedwater pumps. TS 5.4.1 requires that written procedures shall be implemented for activities outlined in Regulatory Guide (RG) 1.33. Nuclear System Directive (NSD) 104, Material Condition, Housekeeping, Cleanliness, and Foreign Material, Section 104.3, Standard for Cleanliness Levels and Foreign Material Exclusion, which implements RG 1.33 requirements, specified that steps be taken to prevent the introduction of foreign material into systems and components to minimize damaging or harmful effects, such as, changes in system flow characteristics. Contrary to this NSD requirement the rags were left in the UST following work activities during the previous refueling outage. This licensee identified violation was evaluated and, because the rags did not migrate out of the UST, the pumps were tested periodically throughout the last plant online operating period, and no degradation of flow characteristics were identified, it was determined to be of very low safety significance (Green). This issue was entered into the licensee's corrective action program as PIP-O-02-5815.

- TS LCO 3.4.13.a requires that RCS leakage shall be limited to “No Pressure Boundary Leakage,” when in Modes 1, 2, 3 and 4. The associated action statement requires that with any pressure boundary leakage, be in Hot Standby within 12 hours and in Cold Shutdown within the following 36 hours. Based on results of the Unit 2 reactor head visual examination detailed in section 4OA5.3 of this report, the licensee identified seven CRDM penetrations (nozzle nos. 8, 9, 19, 24, 31 ,42 and 67) with evidence of wet leakage which required repair. This was discovered during inspections of the reactor head penetrations while the plant was in Mode 5; therefore, the licensee met the required action upon discovery of the condition. Although it is not possible to determine when the reactor vessel head penetration leakage began, it is clear that it had existed for a time greater than the 12 hours required to be in Hot Standby and therefore, constitutes a violation of the TS. As indicated in Section 4OA5.3, this licensee identified violation was determined to be of very low safety significance (Green) and was entered into the licensee's corrective action program as PIP O-01-05496**.**

- 10 CFR 50 Appendix B, Criterion XVI, Corrective Actions, requires in part that measures be established to assure that conditions adverse to quality are promptly identified and corrected. PIP-O-01-03287 identified boron accumulation on the body to bonnet flange of Unit 2 building spray valve 2BS-17 during the Code VT-2 pressure boundary Code examinations. To delay the ASME Code Section XI requirement to pull the bolting at that time, the licensee filed a Code relief request (RFR-97-GO-001), which included several actions and requirements to be performed. However, the licensee later identified that the required work was not performed within the required time span and that Code and relief request commitments were not met. The lack of timely corrective actions to resolve the identified ASME Code non-compliance issues is considered to be a violation of 10 CFR 50, Appendix B, Criterion XVI. The licensee identified this violation and captured it in their corrective action program as PIP O-02-0826. Because components maintained their functionality, this violation is of very low significance (Green).

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Batson, Mechanical/Civil Engineering Manager
D. Baxter, Engineering Manager
T. Colman, ISI Coordinator
T. Curtis, Reactor & Electrical Systems Manager
W. Foster, Safety Assurance Manager
P. Fowler, Access Services Manager, Duke Power
D. Hubbard, Modifications Manager
B. Hamilton, Station Manager
R. Jones, Site Vice President
T. King, Security Manager
B. Medlin, Superintendent of Maintenance
B. Millsaps, Vessel Head Penetration Inspection Project Manager
L. Nicholson, Regulatory Compliance Manager
R. Repko, Superintendent of Operations
J. Smith, Regulatory Affairs
J. Twiggs, Manager, Radiation Protection
J. Weast, Regulatory Compliance

NRC

L. Olshan, Project Manager

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-270/02-05-05	URI	Determination of Consequences for not Maintaining Design Clearances on Feedwater Piping Whip Restraints and Corresponding Risk (Section 4OA2)

Opened and Closed

50-269/02-05-01	NCV	Failure to Take Timely/Effective Corrective Actions When Dispositioning a Component with Identified ASME Code Deficiencies and Non-Compliances (Section 1R08.2)

50-269/02-05-02	NCV	Improper Mode Change with Inoperable Atmospheric Dump Valve (Section 1R12.1)
50-269,270/02-05-03	NCV	Failure to Identify and Correct the Turbine Driven Emergency Feedwater Lube Oil Sump Water Intrusion adverse Condition (Section 1R12.2)
50-269,270,287/02-05-04	NCV	Failure to Perform Surveillance within the Required Periodicity (Section 1R22.2)

Previous Items Closed

50-269/02-05-00	LER	Potential Failure of Manual Atmospheric Dump Valve due to Pressure Locking (Section 4OA3.1)
50-270/02-01-00	LER	Technical Specification Valve Manually Inoperable Due To Mechanical Interference (Section 4OA3.2)
50-269/2001-S01-00	LER	Security Access Revoked for Falsification of Criminal Record (Section 4OA3.3)
50-270/02-02-00	LER	Unit 2 Reactor Coolant System Pressure Boundary Leakage due to Cracks Found in Reactor Vessel Head Penetrations (Section 4OA3.4)
50-269,270,287/01-08-02	URI	Steam Generator Tube Stresses Resulting from Use of the Station Auxiliary Service Water Tornado Pump (Section 4OA5.2)
2515/150 (Unit 2 only)	TI	Unit 2 Reactor Pressure Vessel Head and Head Penetration Nozzles - NRC Bulletin 2002-02 (Section 4OA5.3)

Items Discussed

None

LIST OF DOCUMENTS REVIEWED

(Section 1RO8.1)

NDE-701, Multifrequency Eddy Current Examination of Steam Generator Tubing at Catawba, McGuire and Oconee Nuclear Station, Rev. 3
NDE-703, Evaluation of Eddy Current Data for Steam Generator Tubing, Rev. 1
NDE-707, Multifrequency Eddy Current Examination of Non-Ferrous Tubing, Sleeves and Plugs

using a Motorized Rotating Coil Probe, Rev. 2
NDE-708, Evaluation of Eddy Current Data for Non-Ferrous Tubing, Sleeves and Plugs using a Motorized Rotating Coil Probe, Rev. 1
NDE-713, Data Management Procedure and Responsibilities in Support of Eddy Current Inspections, Rev. 3
NDE-714, Administrative Guide for Resolving Differences During the Review of Eddy Current Data, Rev. 1
NDE-721, System Administration Procedure for Handling of Raw Eddy Current Data and Results, Rev. 1
Eddy Current Analysis Guidelines for Duke Power Company's Once-Through Steam Generators (OTSG), Rev. 5
Eddy Current Acquisition Guidelines for Duke Power Company's OTSGs, Rev. 8
Data Management Guidelines, Oconee Nuclear Station Steam Generators, Rev. 0
Oconee Nuclear Station Site Technique Qualification, Rev. 3
Steam Generator Management Program (SGMEP) 102, Steam Generator Tube Repair Lists, Rev. 1
SGMEP 101, Dispositioning Guidelines, Rev. 3
SGMEP 102, Steam Generator Tube Repair Lists, Rev. 1
SGMEP 104, Condition Monitoring, Rev. 3
SGMEP 105, OTSG Specific Assessment of Potential Degradation Mechanisms, Rev. 4
OTSG Eddy Current Analysis Guidelines, Appendix A, Bobbin Analysis, Rev. 5
OTSG Eddy Current Analysis Guidelines, Appendix B, Rotating Coil Analysis, Rev. 5
Steam Generator Inspection and Maintenance Workscope - Oconee Nuclear Station 2EOC19, 5/9/01
Oconee Nuclear Station, Unit 2 EOC-19 Refueling Outage Plan
Contractor NDE Training Records
Visual Acuity Examination Records
Calibration/Service Data Records
Eddy Current Examination Technique Specification Sheets (ETTS)
Daily Status Sheets, Oconee Unit 2-EOC19
Technical Specifications §5.5.10, Steam Generator (SG) Tube Surveillance Program
Quality Assurance Surveillance Checklist for 3EOC19, 1EOC20 and 2EOC18 Eddy Current Acquisition
LER 50-270/2002-003-000, Problem Investigation Process No. O-02-6118, Steam Generator Tube Leak During In-Situ Pressure Test
In-Situ Pressure Test Summary for Oconee Unit 1 (April 2002)
PIP O-02-02870
PIP O-02-06118

(Section 1RO8.2)

Framatome ANP Nondestuctive Examonation Procedure 54-ISI-100-09, Remote Blade Probe and Rotation Probe Ultrasonic Examination of Reactor Head Penetrations, dated 9/9/02
Duke Power Company NDE 600, Ultrasonic Examination of Similar Metal Welds in Ferritic and Austenitic Piping Rev 14, dated 10/1/01
Framatome ANP Weld Specification Procedure WP3/43/F43TBSCa-01,Machine Temper Bead GTAW, dated 8/26/02
Framatome ANP Weld Procedure Qualification Record PQ7164-02, PQR for Weld Specification Procedure, dated 2/8/02
Framatome ANP Weld Procedure Qualification Record PQ7183-01, PQR for Weld Specification

Procedure, dated 2/20/02

PDI Generic Procedure for Straight Beam Ultrasonic Examination of Bolts and Studs PDI-UT-5, Rev C

Duke Power Company NDE 25,Magnetic Particle Examination Rev 20, dated 2/10/02

Duke Power Company MP/0/A/1150/029, Reactor Vessel Head Penetrations - Visual Inspection.

PIP O-97-04251,Code Requires evaluations for relevant conditions found during VT-2 exam to be performed prior to continued service & evaluation to be submitted to regulatory authority, dated 10/05/1997

PIP O-00-001593, leakage or boron accumulation on 11 mechanical joints dated 4/27/00

PIP O-01-02071, ASME Section XI ISI VT-2 Pressure Testing boron accumulation on 6 mechanical joints, dated 5/29/01

PIP O-01-03287, ASME Section XI ISI VT-2 Pressure Testing leakage or boron accumulation on 46 mechanical joints, dated 9/05/01

PIP O-01-05107, ASME Section XI ISI VT-2 Pressure Testing leakage or boron accumulation on 6 mechanical joints, dated 12/05/01

PIP O-02-00449 Work Request were incorrectly voided, VT-2 exam identified boron on valves, dated 1/25/02

PIP O-01-01876, The installed Unit 1 1B CCW Pump was repaired at a non-qualified supplier and has several ASME Code compliance issues, dated 5/17/01

PIP O-02-00347, A Transportability review indicates that the CCW Pump Refurbishment Project should be evaluated for ‘non-OEM refurbishment vendor’ issues, dated 1/26/02

PIP O-02-00826, ASME required Code activity was not performed, dated 2/21/02

PIP O-02-06513, Untimely Corrective Action Resolution for 1B CCW Pump ASME Code Issues, dated 11/12/02

PIP O-03-00185, ASME NDE disposition for PIP O-01-01876 Corrective action 17 needs to be reviewed for compliance with regulatory ASME requirements, dated 01/14/03

PIP O-01-00055, Unit 1 Inconsistency regarding the issue of filler metal and documentation on weld tickets, dated 1/04/01

PIP O-01-04797, Unit 3 RCS level decrease due to leakage past valves 3LP-16 and 3HP-241 seats, dated 1/04/01

PIP O-01-03832, Unit 3 Tube fitting downstream of containment isolation valve 3RC-7 (U3 PZR Sample Isol Pene#1 has an active leak, dated 10/18/01

PIP O-02-00722, ASME Section III Subsection NF designation for pipe supports is needed to address questions from ANII, dated 2/14/02

PIP O-02-02149,NRC Notice 2002-13 has been Reviewed and Determined to Be Applicable to Oconee Pressure Vessel Heads, dated 4/16/2002

NCR 6018784-00, PT examinations of Nozzle 60 and 63 revealed rejectable indications in the base metal region, Rev 00

NCR 6018784-01, After grinding & performing additional PT on Nozzle 63 per NCR 6018784-00, a larger rejectable indication in the base metal was detected, Rev 01

NCR 6018784-02, After acid etching Nozzle 63 NCR 6018784-01 an underbead crack or lack of fusion was observed propagating along the fusion line, Rev 02

Framatome ANP Ultrasonic Examination Calibration Report T2294-01.25.24 for Repaired Nozzle #18, dated 10/21/2002

Framatome ANP Ultrasonic Examination Report T2294-16.03.59 Results for Repaired Nozzle #18, dated 10/21/02

Framatome ANP Ultrasonic Examination Report A2294-16.28.03 Results for Nozzle #47, dated 10/21/02

Framatome ANP Ultrasonic Examination Report Results A2295-12.00-51 for Nozzle #61, dated

10/22/02
Framatome ANP Liquid Penetrant Examination Report nozzle #1, dated 10/23/02
Framatome ANP Liquid Penetrant Examination Report nozzle #60, dated 10/23/02
Framatome ANP Liquid Penetrant Examination Report nozzle #63, dated 10/23/02
Framatome ANP Liquid Penetrant Examination Report nozzle #67, dated 10/23/02
Assessment of Oconee U1 EOC19 Welding and Inservice Inspection (ISI) Activities File No. SA-00-46(ON)(RA)(MNT), dated 1/10/01
Octagon Process, Inc. Certificate of Analysis Ferromor ND 8, Lot# F-21312 dated 8/8/00
Duke Energy Corporation Oconee Nuclear Staion, Unit 1 Request for ASME Code Relief No. 2002-09, dated 12/16/03
Duke Energy Corporation Oconee Nuclear Staion, Unit 1 Request for ASME Code Relief No. 2002-10, dated 12/16/03

(Section 2OS1)

Standard Health Physics Procedure (SH) SH/0/B/2000/012, Access Controls for High, Extra High, and Very High Radiation Areas, Rev. 1
SH/0/B/2000/005, Posting of Radiation Control Zones, Rev. 1
Health Physics Procedure (HP) HP/0/B/1000/054, Radiation Protection Routines, Rev. 37
HP/0/B/1000/099, Diving Operations, Rev. 2
Radiation Dosimetry Procedure (RD) RD/0/B/4000/15, Nuclear Site Area, Monitoring, Rev. 7
HP/0/B/1000/097 Radiological Protection Requirement For Independent Spent Fuel Storage Installation (ISFSI) - Phase III and IV (DSCs 41-84)
Certificate of Compliance for Spent Fuel Storage Cask No. 1004, Amendment Effective Date 9/12/01
Independent Spent Fuel Storage Installation (ISFSI) Technical Specifications (TS), 9/17/01
RWP 2010, Unit 2 Reactor Building (U2 Rx Bldg) Install and Remove Scaffolding, Rev. 13
RWP 2011, U2 Rx Bldg in Service Inspection, Rev. 9
RWP 2023, U2 Rx Bldg Painting/Stenciling/Azimuth and Coating/Sealing Work, Rev. 8
RWP 2360, U2 Rx Bldg A & B OTSG Replacement Preparatory Work, Rev. 2
Radiation Survey Number (#) 102502-24, Unit 2 Letdown Cooler Room, 10/24/02
Radiation Survey # 103002-18, Unit 2 Letdown Cooler Room, 10/30/02
Radiation Survey # 101602-31, Unit 2 Reactor Building Basement, 10/16/02
Radiation Survey # 110702-16, Unit 2 Reactor Building Basement, 11/07/02
Radiation Survey # 101102-18, Independent Spent Fuel Storage Installation, 10/11/02
Radiation Survey # 072202-2, Horizontal Storage Module, 7/22/02
TLD results for ISFSI Boundary, 2ndQuarter 2001 (2Q01), 3Q01, 4Q01, 1Q02, 2Q02
Respiratory Evaluations for Unit 2 RFO 2002, Activities as of November 7, 2002
Oconee Nuclear Station Internal Dose Assessments 10/1/01 through 10/31/02
Duke Power Company Assessment Report, GO-02–15 (NPA)(RP)(ALL) conducted February 4, through February 14, 2002
PIP O-01-05090, Manager field observation of deficiency in physical condition of signs used for posting and crudburst controls, 12/11/01
PIP O-02-00194, Higher than normal radiation levels observed in the low exposure waiting area of unit 3 east penetration room, 1/17/02
PIP O-02-00330, Two technicians entered a posted contaminated without protective clothing, 1/24/02
PIP O-02-00940, Door to unit 2 room 217 found propped open blocking radiation and safety postings from view, 2/28/02
PIP O-02-02358, Key to room 304 not returned to RP as required, 4/24/02

(Section 2OS3)

Performance Test (PT) procedure PT/0/A/0230/001, Radiation Monitor Check, Rev. 126
General Employee Training, Advanced Respiratory Protection Self-Contained Breathing Apparatus - (SCBA), Rev. 7
System Chemistry Manual (SCM) 4, Post Accident Liquid Sampling Systems Position Relative to NUREG-0737, Appendix A, Oconee Nuclear Station, Rev.5,
Health Physics Procedure (HP), HP/0/B/1000/067E, Quality Assurance for Automated Personnel Monitors, Rev. 16
HP/0/B/1003/016, Calibration of the Automated Personnel Monitors, Rev. 15
HP/0/B/1003/021, Procedure for the Calibration of the Wholebody Counting System, Rev. 4
HP/1/A/1009/017, Operating Procedure for the Post-Accident Containment Air Sampling System, Rev. 17
HP/0/B/1010/002, Radiological Respiratory Quality Assurance, Rev. 15
HP/0/B/1010/017, Breathing Air Quality Control Test Procedure, Rev. 7
HP/0/B/1010/004, Selection of Proper Respiratory Protective Equipment and Respiratory Surveillance Requirements, Rev. 23
Unit 2 (U2), Area Radiation Monitor (RIA)-3, Containment Area, completed 5/23/01
Unit 1 (U1) RIA5, Reactor Building Refueling Deck, conducted 4/25/02
U2, RIA5, Incore Area, completed 1/31/01
Unit 3 (U3) RIA5, Incore Area, Reactor Building Refueling Deck, completed 2/27/01
U1, RIA8, Hot Chemistry Laboratory Area, completed completed 1/31/01
Procedure Process Record (PPR) HP/1/A/1009/017, Operating Procedure for the Post-Accident Containment Air Sampling System, Rev. 17, conducted 8/7/02
PPR HP/2/A/1009/017, Operating Procedure for the Post-Accident Containment Air Sampling System, Rev. 16, conducted 9/11/02
PPR HP/3/A/1009/017, Operating Procedure for the Post-Accident Containment Air Sampling System, Rev. 17, conducted 7/18/02
PPR HP/1/A/2002/004D, Test Procedure for Operation of the Post Accident Liquid Sampling System (PALSS), Rev.33, conducted 10/24/02
PPR Chemistry Procedure (CP)/1/A/2002/004D, Test Procedure for Operation of the PALS, Rev.33, conducted 8/21/02
PPR CP/1/A/2002/004D, Test Procedure for Operation of the PALS, Rev. 33, conducted 8/21/02
PPR HP/0/B/1010/002, Radiological Respiratory Quality Assurance, April 2002, through September 2002
PPR Calibration of Automated Personnel Monitor, HP/B/0/1003/016, Personnel Contamination Monitor (PCM)-1B Equipment Serial Numbers (S/Ns) 974, 934, 953, conducted January 2002; and PCM 1C 135, conducted January 2002
Grade D Air Quality Certificates of Analysis for MAKO Air Compressor; Quarterly Sample Results from December 2001 through September 2002
Whole Body Counter Library Radionuclide Data as of October 15, 2002
PPR HP/O/B/1003/21, Procedure for Calibration of the Wholebody Counting System, Rev. 4, for People Mover Equipment conducted 03/21/01, and 04/08/02; and Chair Equipment conducted 03/21/01, and 03/11/02
Oconee Nuclear Station Data Base for Respiratory Protection Training, Fit Testing and Medical Qualification as of November 5, 2002
Employee Qualifications and Skills System Data Base Training Status for Operation of Post Accident Liquid Sampling System and Operation of Post Accident Gaseous Sampling System as of 11/06/02

Calibration Records/Certificate of Calibration for the following Portable Instrumentation: GM Detectors including E-120 Serial Number (S/N) 145577, Calibration Date [10/09/02]; 6112B Teletectors S/N 50797, 10/23/02, and S/N 68307, 10/14/02; Ion Chambers RO-20 S/N 1066, 08/19/02, and S/N1327, 5/20/02; and ASP-1 Neutron Monitoring; S/N 2063, 06/04/02
PIP O-02-02913, Reactor Operator Standing Watch without Respirator Glasses, 05/28/02
PIP O-01-04326, Heightened Potential for Personal Error in Process of Issuing RP Instruments and Respirator Issue, 11/14/01
PIP O-01–04269, Respiratory Program did not Update Employee's Training for Respiratory Use, 11/13/01
PIP O-01-04327, Potential for Cross-Contamination of Respirators and Work Holdup, 11/14/01

(Section 2PS1)

Instrument Procedure (IP) IP/0/B/0360/038, Sorrento RIA-32 Auxiliary Building Gas Monitor, Rev. 13
IP/0/B/0360/043, Sorrento On-Line Dual Range Gas Monitor, Rev. 13
IP/0/B/0360/031, Sorrento Process Radiation Monitor Skid Calibration, Rev. 26
Chemistry Procedure (CP) CP/0/B/5200/048, Resin Recovery System Operation, Rev. 76
Oconee Nuclear Station Off-site Dose Calculation Manual, Rev. 42
Radiation Protection Policy Manual, Policy V-02, Quality Control of Count Room Instrumentation, Rev. 0
HP/O/B/1000/067, Quality Assurance for Count Room Instrumentation, Rev. 08
HP/O/B/1001/009, Count Room Instrument Performance Check Procedures, Rev. 12
HP/O/B/1003/019, Calibration and Setup of HPGE Detectors Using the Count Room Acquisition System Software, Rev. 5

Effluent Monitor 3RIA-32, Calibration Data 8/30/01
Effluent Monitors 3RIA-37/38, Calibration Data 5/15/02
Effluent Monitors 2RIA- 43 thru 46, Calibration Data 8/14/02
Liquid Waste Release # 2002205, conducted 11/6/02
Interlaboratory Cross Check Program for calendar year (CY) 2001 and year-to-date (YTD) 2002
PIP O-01-4389, Liquid waste release terminated. Flow to RIA-33 was not restored following cleaning of the RIA-33 chamber, 11/15/01
PIP O-01-04513, Dilution flow from Keowee Tailrace fluctuated during liquid waste release, 11/19/01
PIP O-02-01952, No written guidance for use of effluent accounting computer program when noble gas activity is not detected in gaseous effluent samples, 4/9/02
PIP O-02-05048, Liquid waste release terminated. Liquid waste activity indicated by RIA-33 was not within the range calculated for the release 9/25/02
Oconee 2001 Annual Effluent Release Report, dated April 16, 2002

(Section 2PS3)

SH/0/B/2000/006, Removal of Items from RCA/RCZs and use of Release/Radioactive Material Tags, Rev. 1
Offsite Dose Calculation Manual, Rev. 41
Procedure 700, Preparation of Environmental Sampling Supply Kits, Rev. 0
Procedure 701, Milk Sampling at Oconee Nuclear Station, Rev. 0
Procedure 702, Airborne Radioiodine and Airborne Particulate Sampling at Oconee Nuclear Station, Rev. 0

Procedure 705, Broadleaf Vegetation Sampling at Oconee Nuclear Station, Rev. 0
Procedure Process Record, HP/B/0/1003/016, Calibration of Automated Personnel Monitor, Rev. 15, for Small Article Monitor (SAM) Equipment Serial Number (S/N) 181 conducted 4/11/02, S/N 203 conducted 6/21/02, S/N 204 conducted 5/16/02, and S/N 261, conducted 3/14/02
Semiannual calibration of primary and backup meteorological monitoring instrumentation, completed 8/6/02
REMP air-sampling equipment annual calibrations: location 60, S/N LVAS42, conducted 11/20/2001; location 74, S/N LVAS51, conducted 11/27/2001; location 77, S/N LVAS55, conducted 12/3/2001; location 78, S/N LVAS76, conducted 12/3/2001; location 81, S/N LVAS44, conducted 11/20/01
PIP O-01-04124, Radioactive Material Discovered in Clean Area, 11/07/01
PIP O-02-00836, Lack of Procedural Guidance for Control of Radioactive Material, 02/21/02
PIP O-02-01322, Radiation Protection Personnel Contamination Monitors and Small Article Monitors used for Outage Purposes No Longer Reliable and are Labor Intensive to Maintain, 03/21/02
PIP O-02-01487, Assessment of Vendor Performance of the REMP, 3/27/02
PIP O-02-02588, Air Radioiodine Cartridges Placed in the Wrong Direction in Air Sampler Head, 5/7/2002
PIP O-02-02704, Assessment of Procedure Use and Adherence in Vendor Collection of REMP Samples, 5/15/02
Oconee Nuclear Station - Annual Radiological Environmental Operating Report for 2001, submitted 5/8/02

(Sections 4OA1.1 and .2)

SH/0/B/2002/001, NRC Performance Indicator Data Collection, Validation, Review, and Approval, Rev. 1
HP/0/B/1000/016, Radiation Protection Requirements for Steam Generator Work, Rev. 20
Oconee Nuclear General Exposure Listing 01/01/01 through 2/31/01, and 01/01/02 through 8/5/02
Oconee Nuclear Station, 2001 Annual Radioactive Effluent Release Report, dated 04/18/02
HP/0/B/1000/016 records (Enclosure 5.2, OTSG Platform Worker Dose Tracking) associated with RCA exits on 4/18/02 and 10/16/02, in which dose alarm was exceeded by 100 mrem or more
PIP O-02-06361, Need to ensure that Performance Indicators for the Occupational Radiation Safety Cornerstone are captured and reported correctly, 11/7/02

LIST OF ACRONYMS

ADV	-	Atmospheric Dump Valves
AFIS	-	Automatic Feedwater Isolation System
ANSI	-	American National Standards Institute
ARM	-	Area Radiation Monitor
ASME	-	American Society of Mechanical Engineers
ASW	-	Auxiliary Service Water
ATWS	-	Anticipated Transient Without Scram
BIQ	-	Background Investigation Questionaire
CAM	-	Continuous Air Monitor
CCW	-	Condenser Circulating Water
CFR	-	Code of Federal Regulations
Cs	-	Cesium
CRDM	-	Control Rod Drive Mechanism
CY	-	Calendar Year
DAW	-	Dry Active Waste
DEC	-	Duke Energy Corporation
EAD	-	Electronic Alarming Dosimetry
ECCW	-	Emergency Condenser Circulating Water
EFW	-	Emergency Feedwater
EHRA	-	Extra High Radiation Area
EOC	-	End-of-Cycle
EPSL	-	Emergency Power Switching Logic
ES	-	Engineered Safeguards
ESV	-	Essential Siphon Vacuum
ET	-	Eddy Current
HELB	-	High Energy Line Break
HPI	-	High Pressure Injection
HPT	-	Health Physics Technician
HRA	-	High Radiation Area
ID	-	Inner Diameter
IR	-	Inspection Report
ISFSI	-	Independent Spent Fuel Storage Installation
KHS	-	Keowee Hydro Station
KHU	-	Keowee Hydro Unit
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LLD	-	Lower Limit of Detection
LOCA	-	Loss Of Coolant Accident
LOOP	-	Loss Of Offsite Power
LPI	-	Low Pressure Injection
MBM	-	Manufacture Burnish Marks
MSLB	-	Main Steam Line Break
MT	-	Magnetic Particle
NCV	-	Non-Cited Violation
NDE	-	Non-Destructive Examination
NEI	-	Nuclear Energy Institute
NIST	-	National Institute of Standards and Technology
NRC	-	Nuclear Regulatory Commission

NRR	-	Nuclear Reactor Regulation
NSD	-	Nuclear System Directive
OAC	-	Operational Aid Computer
OD	-	Outer Diameter
ODCM	-	Offsite Dose Calculation Manual
ONS	-	Oconee Nuclear Station
OSC	-	Operational Support Center
OTSG	-	Once Through Steam Generator
PADS	-	Plant Access Data System
PASS	-	Post-Accident Sampling System
PCM	-	Personnel Contamination Monitor
PI	-	Performance Indicator
PIP	-	Problem Investigation Process report
PM	-	Preventive Maintenance
PMT	-	Post-Maintenance Test
PRA	-	Probability Risk Assessment
PT	-	liquid dye-Penetrant
PWSCC	-	Primary Water Stress Corrosion Cracking
QC	-	Quality Control
RBS	-	Reactor Building Spray
RCA	-	Radiologically Controlled Area
RCS	-	Reactor Coolant System
REMP	-	Radiological Environmental Monitoring Program
REV	-	Revision
RG	-	Regulatory Guide
RP	-	Radiation Protection
RPV	-	Reactor Pressure Vessel
RTP	-	Rated Thermal Power
RWP	-	Radiation Work Permit
SAM	-	Small Article Monitor
SAR	-	Safety Analysis Report
SCBA	-	Self-Contained Breathing Apparatus
SDP	-	Significance Determination Process
SFP	-	Spent Fuel Pool
SG	-	Steam Generator
SGTR	-	Steam Generator Tube Rupture
SLC	-	Selected Licensee Commitments
SR	-	Surveillance Requirement
SSC	-	Structure, System and Component
SSF	-	Standby Shutdown Facility
SSW	-	Siphon Seal Water
TDEFW	-	Turbine Driven Emergency Feedwater
TLD	-	Thermoluminescent Dosimeter
TMI	-	Three Mile Island
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
UST	-	Upper Surge Tank
UT	-	Ultrasonic
VHP	-	Vessel Head Penetrations

VHRA	-	Very High Radiation Area
VT	-	Visual
WBC	-	Whole Body Counting
WO	-	Work Order
WR	-	Work Request
YTD	-	Year-To-Date