U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Power Company
Facility:	Oconee Nuclear Station, Units 1, 2 & 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	October 6, 1996 - November 16, 1996
Inspectors:	M. Scott, Senior Resident Inspector G. Humphrey, Resident Inspector N. Salgado, Resident Inspector N. Economos, Reactor Inspector R. Freudenberger, Senior Resident Inspector D. Forbes, Reactor Inspector R. Carroll, Project Engineer R. Baldwin, Reactor Inspector P. Kellogg, Reactor Inspector
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Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2 & 3
NRC Inspection Report 50-269/96-16,
50-270/96-16, 50-287/96-16

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by two regional safety inspectors, one visiting senior resident, and one project engineer.

Operations

- The Unit 1 shutdown and associated rod drop test was performed in a professional and controlled manner. (Section O1.2)
- Unit 2 midloop operation was well controlled and coordinated. (Section O1.3)
- The overall cold weather protection program was determined to be adequate. (Section O1.4)
- A Non-Licensed Operator was aggressive in the identification of a discrepant condition on safety-related equipment. (Section O4.1)
- Initial review of operator training associated with Integrated Control System modifications indicated that the training was adequate. An inspector followup item was identified to address licensed operator qualification issues associated with the modification.

Maintenance

- Specific observed maintenance activities were generally performed thoroughly and professionally. (Sections M1.1 and M1.2)
- The licensee's welding instruction and field inspection programs were appropriate. The licensee's efforts to identify and document field conditions following the Unit 2 water hammer event were commensurate with applicable code requirements and quality standards, and reflected a conservative attitude. (Section M1.3)
- Inservice Inspection examinations scheduled for this outage were being performed as required by well trained personnel following procedures written in compliance with applicable code requirements. Personnel performing the inspections were well qualified to execute their assigned tasks. Eddy current examinations were consistent with Technical Specifications (TS) 4.17 requirements. Three tubes were identified in Steam Generator "B" with primary water stress corrosion cracking indications in the roll transition region of the upper tubesheet. A decision had not been reached on their disposition and/or repair at the end of the inspection period. (Section M1.4)

- Maintenance personnel, based on identified drawing discrepancies with as-built configuration, installed blanks on the Unit 1 and Unit 2 auxiliary building ventilation system vents supplying the control battery rooms. Subsequently, it was determined that the blanks adversely affected the Unit 1 and Unit 2 penetration room ventilation system (PRVS) tests, and should not have been installed. A violation was identified to address the failure of Maintenance personnel to initiate a Problem Investigation Process Report for problem evaluation when drawing discrepancies were identified. (Section M4.1)

- Maintenance personnel failed to implement the procedural requirements for restoration of the Main Steam Safety Valves (MSSV) by not ensuring spindle nut cotter pins were installed on two Unit 3 MSSVs and improperly installing the cotter pins on four Unit 2 MSSVs. These examples of poor Maintenance performance could have led to entry into Emergency Operating Procedures and/or loss of the steam generators as decay heat removal paths. An apparent violation with two examples was identified. (Section M4.2)

Engineering

- The licensee's interim corrective actions with respect to a recent main feedwater pump failure were adequate. (Section E1.1)

- A violation was identified concerning an inadequate Letdown Storage Tank (LDST) Level Calibration Procedure. (Section E8.1)

- A non-cited violation was identified to address the inadvertent removal of redundant power on the Unit 1 and Unit 3 LDST instrumentation. (Section E1.2)

Plant Support

- The licensee effectively implemented a program for shipping radioactive materials and for classifying waste destined for burial. (Section R1.1)

- The licensee's water chemistry control program for monitoring primary and secondary water quality had been implemented in accordance with the TS requirements and the EPRI guidelines for Pressurized Water Reactor water chemistry. (Section R1.2)

- The licensee was maintaining a high level of operability for radiation monitors in 1996. (Section R2.1)

- The transportation training focused on good radiological control work practices and compliance with transportation regulations. (Section R5.1)

- The licensee had complied with the TS required program for conducting audits of station activities. (Section R7.1)

- A non-cited violation was identified for an inadequate procedure in the Technical Support Center for terminating an Unusual Event. (Section P3.1)

Report Details

Summary of Plant Status

On October 4, 1996, Unit 1 reduced power to fifteen percent and the main turbine generator was taken offline. The unit remained at fifteen percent power to provide steam for the shutdown of Unit 3. On October 9, 1996, the unit was shutdown, and remained in that condition throughout the rest of the reporting period (Section 01.2).

Unit 2 remained in cold shutdown for the entire reporting period. On October 17, 1996, the licensee entered midloop operation to replace a leaking cold leg resistance temperature detector (RTD) (Section 01.3).

Unit 3 remained in a refueling mode throughout the entire reporting period.

Review of UFSAR Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

01.2 Unit 1 Shutdown and Rod Drop Test

a. Inspection Scope

On October 9, 1996, the licensee reduced power on Unit 1 from approximately 15 percent and subsequently tripped the unit. The licensee manually tripped the unit to perform a rod drop test. The licensee has a program to check the drop times and evaluate/replace Control Rod Drive Mechanisms (CRDM) if times exceed a 1.40 second administrative limit (TS limit is <1.66 seconds). The inspectors observed the power reduction and the rod drop test.

b. Observations and Findings

The licensee held an effective pre-job briefing on the power reduction and the rod drop test. Reactor engineers were present to support performance of the test. Once the evolutions were understood, the Operations staff cleared the Control Room (CR) of extraneous people and readied the CR for the test.

During the power reduction, all control and parametric indications were nominal. As power approached the trip test point as described in procedure PT/1/A/600/15, Control Rod Movement, power reduction was slowed and control board indications were carefully observed. After the trip, Operations performed appropriate checks to ensure that all rods were in the core and the reactor was shutdown.

Reactor engineers determined that the test was valid and that the rod insertion times, while longer than previous testing times, were well within the allowed TS limits. Nine of the rods did not drop into the core in less than the allowed administrative limit. The administrative limit is used by the licensee to ensure the TS limit is not exceeded. Management determined that the nine CRDMs would require replacement. In addition, based on its approach to the 1.40 second administrative drop time limit, one additional CRDM would also be replaced. The replacement actions were completed during this period.

c. Conclusions

The Unit 1 power reduction and rod drop test were effectively performed in a professional and controlled manner.

O1.3 Unit 2 Midloop Operation

a. Inspection Scope

The inspector reviewed the Unit 2 midloop operations as controlled by procedure OP/2/A/1103/11, Draining And Nitrogen Purging Of Reactor Coolant System.

b. Observations and Findings

During the Unit 2 forced outage, the licensee reduced Reactor Coolant System (RCS) inventory and reached the midloop operations level on October 17, 1996. Unit 2 was in midloop status for approximately eighteen hours. Midloop conditions were required for the replacement of the 2B1 cold leg RTD which was leaking. The inspectors reviewed the licensee's controls prior to the reduction of RCS inventory and verified that the requirements were met while operating at the reduced inventory levels as specified in procedure OP/2/A/1103/11, Enclosure 3.6, Requirements for Reducing Reactor Vessel Level to < 50" on LT-5. This procedure stipulated the sequence and steps required for reduction of RCS inventory and mid-loop operation. It further specified the precautions and limitations to be adhered to while in midloop operations.

The inspector verified that the requirement for two independent trains of RCS level monitoring was met while at reduced inventory. This was accomplished through the use of two permanently installed instruments (LT-5A and LT-5B) and two temporary ultrasonic instruments. During the

approach to midloop, level reduction was properly delayed because of the development of ultrasonic instrument problems. The licensee addressed the problems appropriately. Level indications were displayed in the CR on the LT-5A and LT-5B indicators, the Inadequate Core Cooling Monitor, and on the Operator Aid Computer.

The inspector verified that two trains of core exit thermocouples were available and utilized while at reduced inventory, as well as that the two sources of inventory makeup and cooling were available for operation. Multiple sources of offsite power were also available.

c. Conclusion

The licensee implemented and maintained the requirements specified by procedure while accomplishing reduced inventory operations without incident. The inspector concluded that the Unit 2 midloop operations were well controlled and coordinated.

01.4 Cold Weather Preparations

a. Inspection Scope (71714)

The inspector reviewed the licensee's program to protect equipment and systems against extreme cold weather conditions.

b. Observations and Findings

The licensee's cold weather protection program was based on an evaluation of plant equipment where conditions were such that freeze protection was necessary. The evaluation included plant areas/equipment that have experienced problems in the past. The more significant areas included: (1) the Borated Water Storage Tank (BWST) level indication, (2) the Elevated Water Storage Tank (EWST) level indication, and (3) the cooling water to the Condenser Circulating Water (CCW) pumps.

On November 15, 1996, the inspectors reviewed the status of heat trace alarm panels on all three units. Two annunciators were found to be in the alarm state. However, the affected heaters were not related to freeze protection and both had been identified by the licensee for corrective actions. Control room annunciation was periodically reviewed by the inspectors during routine control room tours. Loss of cooling water flow to the CCW pumps will actuate a CR alarm.

The inspector verified that freeze protection program actions were initiated as required when Control Room Alarm, 1SA9B3, RBV Purge Inlet Temp Low, annunciated indicating outside temperature had reached a low of 40 degrees F. The program response required that various heaters be reviewed for malfunctions and steam supplies be readied for use per OP/0/A/1106/22, Auxiliary Steam System. A second control room alarm annunciates when the outside temperature drops to 35 degrees F. The

requirements for that alarm are outlined in Enclosure 5.12, Cold Weather Checklist, of OP/1/A/1102/20, Shift Turnover. This procedure checklist specified various preventive measures to be implemented such as building doors being closed, dampers being closed, heaters being turned on and verified to be operating properly, proper cooling water flows to outside equipment, trench covers in place, heat tracing operating properly, and building heating systems in service. The inspectors toured areas of the plant, observing damper and door status.

The inspectors reviewed and/or discussed with the licensee the following:

- The most recent Work Orders (WO) that were performed on heat tracing for the BWST level indications [Unit 1, WO91037141 (last performed 2/12/96), Unit 2, WO91037410 (last performed 6/5/95), and Unit 3, WO91037645 (last performed 6/12/96)]. These circuits do not have alarms and a failed heat trace circuit would not be detected by the operator during heat trace panel checks. However, redundant level instrumentation is provided and is heat traced.

- Site discrepancy reports (PIPs 2-96-0252, 0-96-2185, 0-96-2372, and 0-96-0639) had been generated in reference to problems experienced at Oconee Nuclear Station (ONS) and other industry sites. A corporate audit was performed by Duke Power Company (DPC) to formalize a freeze protection program for all three nuclear sites. As a result of that audit, Problem Investigation Process (PIP) report 0-096-0639 was generated to indicate areas that are not consistent between the Duke facilities.

- Liquid radiological waste building freeze protection issues. The liquid waste building has no steam heat and temporary space heaters must be maintained to assure proper protection.

- Procedure upgrades that are planned or being evaluated by site management for implementation.

Based on the above, the inspectors noted that the licensee had initiated enhancements in several programmatic areas. Specific changes are still being pursued by the licensee under the corrective action program. The inspectors verified that the BWST heat trace instrumentation was calibrated on its last normal 18 month frequency. Procedures require that the liquid radiological waste building is manually maintained above freezing by appointed freeze protection personnel. Additional programmatic improvements are scheduled in the licensee's corrective action program.

c. Conclusions

The status of plant freeze protection equipment and program was determined to be adequate. However, the program will be enhanced with the implementation of actions that have been initiated by the licensee.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors used Inspection Procedure 71707 to walkdown accessible portions of the following safety-related systems:

- Keowee Hydro Station
- High Pressure Injection System
- Main Steam System

Equipment operability, material condition, and overall housekeeping were acceptable in all cases. Several minor discrepant conditions were noted by the inspectors in the Units 1 and 2 Emergency Core Cooling System (ECCS) pump areas. These were present after an extensive paintout period in these areas. Examples of the found conditions were bent instrument lines, taped covers on mechanical joints, and trash in open, uncovered floor drains. The discrepancies were reported to the licensee.

04 Operator Knowledge and Performance

04.1 Unit 3 Reactor Building Purge System (71707)

On November 12, 1996, alarm 3SA-9, RBV Purge Inlet Temp Low, annunciated on the Unit 3 Control Room panel. A Non-Licensed Operator (NLO) was dispatched to the 3B Reactor Building Inlet Purge equipment area to determine the cause for the alarm. The NLO completed the alarm response requirements and found no problems. However, the operator noticed that a damper indicator lever was not in the position that he had remembered it during previous inspections of that equipment. He opened a duct panel door and inspected the inside of the duct. As a result, the operator identified that the inlet dampers had been damaged. Subsequently, the purge system was shut down for repairs.

The inspectors noted that the NLO aggressively pursued the cause of the alarm. The Auxiliary Steam system was experiencing problems at that time and low steam pressure was the most likely suspect for the annunciated condition since the heating steam was supplied from that source. The NLO demonstrated excellent operational skills by understanding the equipment and continuing to investigate the cause of the problem.

05 Operator Training and Qualification

05.1 Operator Requalification Program (71001)

a. Inspection Scope (71001)

During the period of November 12-15, 1996, the inspector used guidance from Inspection Procedure 71001 to review and evaluate the licensee's operator requalification program in the area of the Unit 3 Digital Integrated Control System (ICS) modification training, start-up training, lesson plan (system description) evaluation, examination review, operator license disposition and procedural validation.

b. Observations and Findings:

The inspector observed two sessions of a start-up training lab on the Unit 1 simulator with the Unit 3 digital ICS model installed. The simulator training crews consisted of four operators. The inspector observed two of the four operators performing start-up training using the new digital ICS. The two additional operators were questioned by the instructor while the start-up lab was being conducted. When the first group was done with the start-up lab the two groups exchanged positions. During the start-up training lab the inspector conducted interviews concerning their training with six operators, two Reactor Operators and four Senior Reactor Operators. Start-up training is scheduled to be completed January 2, 1997.

The inspector found that each operator considered the first round of classroom training adequate in providing technical knowledge concerning the digital ICS modification. The inspector questioned the operators concerning the ability to operate both digital and analog ICS models. The operators stated that they felt it would not be a problem going between the different ICS models provided some type of "just-in-time" training was provided prior to assuming the shift on either unit. The operators interviewed also stated that their opinion on the ability to operate both the new and old ICSs may change once they became exposed to the malfunction training scheduled in December, 1996.

The inspector reviewed lesson plan OP-OC-STG-ICS, Integrated Control System (STG-ICS). The training department provided sixteen hours of classroom training to plant operators. This training was completed for all licensed personnel on October 8, 1996. Following this training, additional ICS review was provided and an examination was prepared for all licensed personnel. All licensed operators received the examination. However, eighteen personnel have to be retested due to receiving a failing grade. The inspector reviewed one comprehensive ICS modification examination. The examination contained twenty detailed multiple choice questions concerning the modification and was found to adequately test that knowledge.

The inspector discussed with the Training Department's staff their recommendation to the Operations Department concerning the dispensation of current license holders. At the time of the inspection, the Training Department had not decided on what their recommendation would be pertaining to licensed operators. The inspector determined that the Training Department would not make a recommendation until malfunction training was started, allowing them time to evaluate problem areas not previously identified. Malfunction training was scheduled for the first crew during the week of December 2, 1996. Since the results of malfunction training will be an decision point, this item will be tracked under Inspector Followup Item (IFI) 50-287/96-16-06, ICS Malfunction Training Results.

The inspector observed two separate sessions of the validation of testing procedures. The procedures being evaluated were marked "Preliminary." The group was comprised of plant engineers, operations personnel and training instructors. The procedures evaluated were TN/3/B/2989/00/ALI-26, ICS/NNI Transient Testing at Power, and TN/3/B/2989/0/A-03, Loss of ICS/NNI Power Testing at 15% Reactor Power. The inspector observed a good working relationship within this group.

c. Conclusions

The inspector concluded that the first round of start-up training conducted on the new digital ICS model was satisfactory. The inspector also concluded that operators felt confident with going from the analog to the digital ICS, however, the inspector was unable to determine the actual impact without viewing the malfunction training scheduled in December. The inspector determined that the sixteen hours of operator requalification class room training contributed to the confidence exhibited by the operators during interviews.

By reviewing the system description, the inspector determined that the new ICS model uses inputs differently than the analog version. The system description was well written in clear and concise language. This document was formatted in a logical sequence, which enabled a comprehensive understanding of a very complex system.

The inspector concluded from the review of one examination that a comprehensive examination was administered to the operators. The examination contained pertinent test items. The examination encompassed a range of aspects concerning the integrated control system.

The inspector concluded the validation process for the testing procedures was conducted in a professional manner. The validation team discussed various aspects of the testing scheme while providing insights concerning certain aspects of plant systems and contingency actions not addressed in the procedures.

08 **Miscellaneous Operations Issues** (92901, 92700)

08.1 (Closed) URI 50-270/96-12-04 Pressurizer Safety Valve 2RC-67 Operability

This item addressed the technical issues associated with pressurizer safety valve (PSV) 2RC-67 not lifting within the required setpoint. As documented in PIP 2-096-0945, the early actuation of the 2RC-67 would delay a reactor trip for transients that trip on high pressure, or the reactor may trip on a different trip function. The licensee performed an analysis on the past operability of 2RC-67, as documented in calculation OSC-6687, PSV Past Operability Evaluation (PIP #2-096-0945). The conclusion of OSC-6687 determined that PSVs would have performed their intended safety function during Cycle 15 based on the licensee's analysis results. The inspector reviewed OSC-6687 and identified no problems. This item is closed.

08.2 (Closed) URI 50-270/96-12-03 Delay In Licensee Event Report (LER) Submittal

This item was opened pending the licensee's results of the past operability review for PSV 2RC-67. The licensee determined that 2RC-67 was past operable as documented in a letter dated October 10, 1996, from Duke Power Company to the U.S. Nuclear Regulatory Commission. Therefore, the licensee determined that the event was not reportable per 10 CFR 50.73. As described above, the inspector reviewed the evaluation and found no problems. This item is closed.

08.3 (Closed) LER 270/96-03 Pressurizer Relief Valve Technically Inoperable

The licensee determined that this event was not reportable, and that the LER was not required. During the initial report, the licensee indicated that PSV 2RC-67 failed to meet its as found set pressure band. After further analysis, it was concluded that 2RC-67 would have performed its intended safety function. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703, 61726)

The inspectors observed all or portions of the following maintenance activities:

- TN/3/A/OE9360/00 Procedure For The Implementation and Verification of Minor Modification OEC-9360 (Wet Tap on CCW-42)
- WO 96063295 Keowee Unit #1 Turbine Sump Pump's Quarterly Test
- PT/3/A/203/04 Low Pressure Injection System Leakage
- MP/0/A/1500/009 Defueling/Refueling Procedure (Unit 3)
- WO 96041652 PM Relays In Switchgear 3TD14
- WO 95056597 NSM-32976, Replacement of 3HP-5
- WO 96084056 Wide Range Instrument Channel Check
- WO 96080249 2HD-50 Valve Replacement
- WO 95028313 OEC-7451, Replace 1SD-40
- WO 96055134 Replace Valve Seat on 3C-20
- WO 96081630 PM Valve 2HPSW-85
- WO 96079756 NSM 2491, Steam Drain Modifications
- WO 96011371 NSM 32979, Replace 2MS-126, 130, and AS-1
- WO 96079787 Investigate and Repair 2LPSW-6

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress.

Quality control personnel were present when required by procedure. When applicable, appropriate radiation control measures were in place.

c. Conclusion

The inspectors concluded that the maintenance activities listed above were completed thoroughly and professionally.

M1.2 Implementation of Temporary Modification to Remove Valve 1LPSW-254

a. Inspection Scope (62707, 40500)

On October 15, engineering personnel performing a visual inspection of valve 1LPSW-254 identified a crack in the valve stem at the keyway. The A train of Low Pressure Injection (LPI) was removed from service, and a temporary modification was initiated to remove the valve from the system. To implement the modification, the licensee installed a mechanical plug downstream of valve 1LPSW-254 to provide an isolation boundary for the work. A temporary modification (TSM 1301) was developed to remove the valve from the piping system and replace it with a spacer. This maintenance evolution rendered the A train of LPI unable to perform its decay heat removal function with the unit in cold shutdown.

The inspector assessed the maintenance activity by performing the following: observation of interdepartmental planning and contingency meetings; observation of management, operations, and maintenance prejob briefings; observation of work in progress; review of Temporary Modification TSM-1301, Temporary Removal of 1LPSW-254 from the Piping System, including the 10 CFR 50.59 evaluation; review of procedure TN/1/A/1301/TM/01M, Procedure to Install Temporary Modification TSM-1301; and attendance at Plant Operation Review Committee Meetings on the subject.

b. Observations and Findings

During the planning of the maintenance evolution, operators identified enhancements that would improve existing procedures to cope with a loss of decay heat removal, particularly with the specific plant conditions that existed at the time the A train was to be isolated. Commencement of the maintenance was delayed until the enhancements could be incorporated into the procedures and described in the operations prejob briefing information.

Management, operations, and maintenance prejob briefings consistently emphasized the actions that would be necessary in response to a loss of decay heat removal.

The temporary modification, its associated 10 CFR 50.59 evaluation, and implementing procedure were complete, of appropriate detail, and developed in accordance with station procedures.

The maintenance, including the installation of the mechanical plug (which was performed by a contractor), was performed in a controlled manner with an appropriate level of management oversight.

c. Conclusion

Contingency planning for a potential loss of the decay heat removal function while a single train of LPI was available during maintenance to remove valve 1LPSW-254 was appropriate. The implementation of the temporary modification was performed in a controlled manner with an appropriate level of management oversight.

M1.3 Maintenance Welding (55050)

a. Inspection Scope

The inspector reviewed the control of welding processes and weld production.

b. Observation and Findings

The inspector determined that the Generation Services Department at Duke's Corporate Offices was responsible for generating and revising the Corporate Welding Manual. This department was also responsible for generating and issuing weld procedure qualifications, welder performance qualifications, and the code required updates used in the field to verify welder qualification and work assignments. Welding procedures and welder performance qualifications were executed to the requirements of the latest approved edition of ASME Code Sections IX and XI as applicable. Welding activities at the ONS are controlled by the Maintenance Welding Manual (manual), and the applicable construction code which controls certain fabrication, inspection and testing requirements for given welds. Mechanical/Civil Equipment Engineering, generates and revises the manual and administers the welding program at ONS. The Superintendent of Mechanical Maintenance implements and maintains control of the welding program. Responsibilities for weld production and QC inspections are assigned to the Mechanical/Civil Manager and to the Maintenance Support Manager, respectively.

As required by the welding manual, Class G, non-QA, piping is installed per the appropriate guidelines with documentation of required inspections. Production welds in this category are subject to a final visual inspection that are performed by the welding supervisor or his designee. Also, Section 9 of the welding manual provided a list of craft responsibilities and the general requirements to be followed during weld fabrication. These included use of appropriate materials,

Field Weld Data Sheet, weld joint details, cleanliness, cold spring, preheating and postweld heat treatment.

The inspector identified the following observations which were discussed with the licensee's cognizant engineer who has been given the responsibility for reviewing and revising the subject manual as part of the overall corporate effort to improve the Duke welding program.

- Visual inspections of completed welds fabricated to B31.1 requirements are presently performed by the welding supervisor or his designee. To provide increased independence, this type of inspection can be done by a welding inspector or QC inspector who has been trained and qualified in accordance with applicable ANSI Standards and Duke's written program.

- Paragraph 9.6 of the welding manual requires the welder/fitter to achieve weld fit-up without unacceptable cold spring. No details or specifics are provided except for the applicable ONS specification given as reference. The control of cold spring appears to be a function best monitored by engineering.

- Preheating is another responsibility for which welders are accountable. Paragraph 9.8 states in part that preheating shall be performed in accordance with the specified Field Weld Data Sheet (FWDS). The inspector noted that the FWDS states the requirement for preheat and the appropriate temperature, but does not identify the procedure which provides the necessary information for acceptable heat treating practices.

In addition to the above, the inspector reviewed applicable FWDS to be used for pipe replacement and check valve installation for the first and second stage reheater drain tanks A and B. FWDS reviewed included L-350, Rev. 17; L-365, Rev. 4; L-231, Rev. 18; L-250, Rev. 17; and L-264, Rev. 3. FWDS reviewed were to be used for welding the following materials:

- Mild carbon steel to like material
- Mild carbon steel to stainless steel material
- Stainless steel to like material

The welding processes to be used for joining these materials were shielded metal arc and gas tungsten arc or a combination of the two. The inspector's review revealed that these procedures were properly qualified and documented in accordance applicable code requirements.

Pipe and Valve Installation - Reheater Drain Line Modification

The instructions and documentation for installation of pipe and valves in the reheater drain system of Unit 2 are described in modification NSM 22941, Part AM1 and Temporary Modification Procedure TN/2/A/2941/0/AM1.

Enclosure 5.4 of the package will be used for instructions and documentation of new pressure retaining welds. Also, the instructions provide for QC/ANI inspections, and associated hold points and for surfaces examinations of root and completed welds. Additionally, cleanliness requirement for carbon and stainless steel piping as recommended by ANSI Standard N45.2.1-73 were added as a quality measure.

Field Inspections

As documented previously in Inspection Report 50-269,270,287/96-15, extensive field inspections were performed by the licensee and contractors focusing on locating branch connections, taking data, and performing calculations to determine whether as built conditions met minimum code requirements. Branch connections that failed to meet code requirements were scheduled for replacement. Additionally, pipe and elbow welds whose location could have rendered them subject to cracking in the weldment or associated base metal were radiographed to determine their integrity. Selected pipe and elbow welds were visually examined for anomalies. Associated surfaces were examined using a magnetic particle examination technique to look for evidence of crack indications. Finally, a consultant was contracted to perform field inspections and to provide stress analysis evaluations with respect to the effects of water hammer on existing piping.

c. Conclusion

The licensee's welding instruction and field inspection appeared appropriate. The licensee's efforts to identify and document field conditions following the Unit 2 water hammer event were commensurate with applicable code requirements and quality standards, and reflected a conservative attitude.

M1.4 Inservice Inspection Unit 3 (73753)

a. Inspection Scope

Observe inservice activities to determine adequacy of nondestructive examination and compliance with code requirements and FSAR commitments.

b. Observation and Findings

The scheduled Unit 3 refueling outage was changed to coincide with the unscheduled shutdown in response to the water hammer events on Unit 2. This outage was identified as End-Of-Cycle 16 (EOC-16) and was the second refueling of the third interval since commercial plant operation. The applicable code was identified as ASME Sections XI and V, 1989 Editions. The scope of the Inservice Inspections (ISI) during this outage was limited to: augmented examinations in response to IE Bulletin 88-08; and followup ultrasonic examinations in response to previously identified rejectable indications in welds No. 3SGA-WG8-1 and 3SGA-WG8-2

of Once Through Steam Generator (OTSG) "A" of Unit 3. This item was documented in PIP No. 3-092-0371 for tracking purposes. In addition, inspections included examination of the pressurizer relief nozzle welds, pressurizer spray nozzle weld and upper head and upper shell course weld.

The inspector observed the examination of the aforementioned welds on the pressurizer. This included system calibration and examination with 0°, 45° and 60° transducers. Duke Non-Destructive Examination (NDE) procedures used for these examinations included NDE-640, Rev. 1, for the 0° scan and NDE-620, Rev. 5, for the 45° and 60° scans.

These procedures have been reviewed on previous inspections and were found to meet code requirements. Calibrations and examinations were properly performed and documented. Indications were evaluated and dispositioned. Limited examinations were calculated and percentage of weld examination/coverage was documented. Personnel who performed the examinations were adequately trained and knowledgeable of code and procedural requirements. Rejectable indications were not identified.

Eddy Current Examination of Unit 3 OTSGs

The scope of examining OTSG tubes at ONS Unit 3 during the current refueling outage (EOC-16) was as follows:

(1) Inspect 100% of inconel-600 plugs and 40% of inconel-690 plugs on the hot leg, using motorized pancake coil (MRPC) probe.

(2) Inspect Lane/Wedge tubes in hot leg of both OTSGs with MRPC.

(3) Inspect selected inconel-600 and -690 sleeves in hot leg of both OTSGs with Bobbin and Plus-Point coil probes.

(4) Inspect 100% of tubes available in both OTSGs with Bobbin coil probe.

(5) Inspect roll transitions in hot leg of both OTSGs with MRPC coil probe.

With respect to item (5) above, a 20% randomly selected sample was scheduled for examination with MRPC coil probe. The sample was subsequently increased to 100% when the examination identified an indication in the roll transition region. This indication was believed to be associated with Primary Water Stress Corrosion Cracking (PWSCC) mechanism.

The licensee plans to pull four tubes for a metallurgical examination to determine conditions associated with tube degradation. Procedures used to perform the examination and analyze results comply with ASME Code

Section XI, 1989 Edition with no Addenda. Also applicable by reference is Regulatory Guide 1.83, July 1975. Applicable procedures include:

NDE-701, Rev. 3:	Multifrequency Eddy Current Examination of Steam Generator tubing at McGuire, Catawba and Oconee Nuclear Stations.
NDE-707, Rev. 3:	Multifrequency Eddy Current Examination on Non-Ferrous Tubing, sleeves and plugs using a motorized rotating coil probe.

In addition to these procedures, the licensee developed a set of guidelines which are used to assist in data acquisition and analysis of data at the Oconee Nuclear Station and to establish consistency and compliance with applicable requirements. These guidelines were as follows:

- Eddy Current Acquisition Guidelines, October 6, 1996
- Eddy Current Analysis Guidelines, October 9, 1996

Data acquisition was being performed by the licensee using Zetec's Eddynet Acquisition system. Data analysis was being performed offsite at the McGuire Nuclear Station, as well as Framatome in Lynchburg, VA and Rockbridge, IL.

At the close of this inspection on October 18, 1996, bobbin coil examination was in progress, but had not reached the point of identifying tubes for plugging. In a similar manner, examination of the roll transition at the upper tube sheet was making good progress, but no evidence of PWSCC had been identified. On October 22, 1996, the licensee's accountable engineer indicated that preliminary evaluation identified three tubes in OTSG "B" with axial indications. The suspect tubes were identified in locations 136-47, 113-114, and 132-1. The licensee expected to have the examination and the list of tubes to be repaired during the week of October 27, 1996.

c. Conclusion

ISI examinations scheduled for this outage were being performed as required by well trained personnel following procedures written in compliance with applicable code requirements. Personnel performing the inspections were well qualified to execute their assigned tasks. Eddy current examinations were consistent with Technical Specifications 4.17 requirements. Three tubes were identified in S/G "B" with PWSCC indications in the roll transition region of the upper tubesheet. No decisions had been reached on their disposition and/or repair at the close of the inspection period.

M4 Maintenance Staff Knowledge and Performance (92902, 62707)

M4.1 Failure To Initiate a PIP

a. Inspection Scope

The inspector reviewed an issue involving the installation of blanks on the auxiliary building ventilation system (ABVS) supply vents which feed the Unit 1 and Unit 2 control battery rooms. The blanks adversely affected the Unit 2 and Unit 1 Penetration Room Ventilation System (PRVS) testing.

b. Observations and Findings

On October 2, 1996, during the performance of PT/2/A/0100/010, Penetration Room Ventilation System Vacuum Test, the PRVS could not maintain a vacuum against the Unit 2 control battery room as documented in PIP 0-096-1960. The licensee determined that Maintenance personnel had installed blanks on the ABVS supply vents feeding the Unit 2 control battery room on September 25, 1996, which adversely affected the PRVS test. On October 9, 1996, the licensee performed PT/1/A/0100/010, Penetration Room Ventilation System Vacuum Test, and the system could not maintain a vacuum against the Unit 1 control battery room. Blanks had also been installed on the ABVS vents feeding the Unit 1 control battery room on September 25, 1996. Isolating the supply air to the battery rooms reduced the pressure in the rooms to the point where it was no longer positive with respect to the penetration room when the PRVS was in operation. The licensee determined that there were no present operability concerns on Unit 1 and Unit 2 since they were shutdown. The Unit 1 past operability evaluation documented in OSC-6679, Penetration Room Allowable Leakage, concluded that the Unit 1 PRVS was past operable from September 25, 1996, through October 9, 1996. The licensee determined that there was no past operability concern for Unit 2 because the blanks were installed while the unit was offline. The inspector noted that there is an open deviation (DEV) on the operability of the PRVS (DEV 50-269,270,287/94-24-04).

The licensee incorporated minor modification ONOE-9540 which removed the installed blanks from Unit 1 and 2 ABVS supply vents in the control battery rooms. The inspector independently verified that the blanks had been removed from the supply vents. The modification will also revise the drawings to reflect the correct as-built configuration (blanks removed). The licensee successfully performed the Unit 1 and Unit 2 PRVS tests after the implementation of ONOE-9540.

In early September 1996, Maintenance personnel identified that station drawings 0-504A and 0-2504B indicated that the subject vents should have been blanked off. The NSM which originally installed the Control Battery Room Air Conditioning Units was also intended to blank off the ABVS supply vents in the rooms. Maintenance initiated work requests

(WR) 96038038 and 96037440 to install the blanks to assist cooling the battery rooms during the summer since the air temperature coming out of the duct was higher than the 80 degree limit for the room. Nuclear Station Directive (NSD) 208, Problem Investigation Process, provides criteria for initiating a PIP for drawing discrepancies. On September 9, 1996, Maintenance personnel identified that drawing 0-2504B did not match as-built conditions, but failed to initiate a PIP as required by NSD 208. The inspector concluded that Maintenance personnel should have initiated a PIP once the drawing discrepancies were identified, then Engineering could have evaluated the installation of the blanks. This is being identified as example one of Violation 50-269,270/96-16-01, Maintenance Failed To Initiate a PIP. On September 12, 1996, Maintenance personnel identified that drawing 0-504A did not match as-built conditions, but again failed to initiate a PIP. This is being identified as example two of Violation 50-269,270/96-16-01, Maintenance Failed To Initiate a PIP.

c. Conclusion

A violation with two examples was identified to address the failure of Maintenance personnel to initiate a PIP to address drawing discrepancies on the missing blanks on the ABVS vents supplying the Unit 1 and Unit 2 control battery rooms. Maintenance initiated WRs that installed blanks on ABVS supply vents which adversely affected the Unit 1 and Unit 2 PRVS testing.

M4.2 Main Steam Safety Valve (MSSV) Cotter Pin Inspection (92902, 40500)

a. Inspection Scope

In May 1996, another B&W plant had a Dresser Main Steam Safety Valve (MSSV) fail to reseat after lifting. This was due to its spindle nut not being held in place by a cotter pin that should have engaged a slot in the nut and a drilled hole in the valve's spindle. The nut vibrated down the spindle and interfered with the valve's downward motion as the lifted. That B&W plant had Main Steam Isolation Valves and a Feed-Only-Good-Generator system. As documented in Inspection Report 50-269,270,287/96-12, the licensee was aware of the problem and determined that the specific problem was not an immediate concern at Oconee because: the Oconee valve vendor was a different manufacturer (Crosby Valve and Gage Company); the valve details, though similar in function, were sufficiently different; the Oconee valve procedure specifics would tend to prevent incorrect cotter pin/nut engagement; and discussions with valve assembly technicians provided no negative findings. Based on this and personnel safety concerns while at power, inspection of the 48 MSSVs (8 per steam line; 16 per unit) was scheduled for the next cold shutdown periods. During recent plant shutdowns to cold conditions for other reasons, the inspectors participated in the inspections and reviewed applicable WOs and PIPs.

b. Observations and Findings

On October 15, 1996, per WO 96080355, the licensee conducted the Unit 1 inspection and did not identify any problems. On October 14, 1996, per WO 96080322, the licensee conducted the Unit 2 inspection which identified that spindle nut cotter pins were improperly installed on four MSSVs. The four MSSVs were 2MS-0001, 2MS-0005, 2MS-0013, and 2MS-0014. Each valve has a nominal lift setpoint of 1100 psig except for 2MS-001, which has a setpoint of 1104 psig. The cotter pins were not bent sufficiently, and could have vibrated out of the spindle nut. The subject MSSVs were located on separate steamline headers; therefore, if the valves failed to reseat under certain conditions both OTSGs could have been lost as decay heat removal paths. On October 21, the licensee performed a past operability evaluation for the four MSSVs. It was concluded that the valves would have performed their protection function by opening, but the valves could not be credited for closing to provide a fission barrier and preventing a loss of inventory. The evaluation also concluded that even if the four valves failed to reseat, the radiological dose released would not have exceeded the 10 CFR Part 100 limits. This conclusion was drawn assuming a Chapter 15 Steam Generator Tube Rupture.

The Unit 3 inspection conducted on October 24, 1996, by the inspectors along with the licensee identified that cotter pins were not installed on two MSSVs. The two valves were 3MS-0010 and 3MS-0001, each with a nominal lift setpoint of 1065 psig and 1104 psig, respectively. The valves were on separate steamline headers; therefore, if the valves failed to reseat under certain conditions both OTSGs could have been lost as decay heat removal paths. The licensee's system operability evaluation concerning the two valves was not available prior to the end of the inspection period.

On October 29, 1996, the licensee made a 10CFR 50.72 notification concerning the two Unit 3 MSSVs missing their cotter pins. The licensee determined that the possibility existed for flow induced vibration to have caused the unsecured spindle nut to rotate down the spindle toward the valve body. Therefore, 3MS-0001 and 3MS-0010 could have been prevented from properly closing, resulting in an potential primary system overcooling event. On October 30, 1996, the licensee made a similar 10 CFR 50.72 notification addressing the four Unit 2 MSSVs having improperly installed cotter pins. The 10 CFR 50.72 section cited in the reports was "Any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident".

During each Unit's respective refueling outage the valves were partially disassembled to perform setpoint tests. The manual lift linkage assembly, which includes the spindle nut, was removed and re-installed each time. The licensee considered the parts removed as not being

safety parts. As reported by the licensee, the Unit 2 valves identified above did not lift (as expected) during the last reactor trip.

The cotter pins on the four Unit 2 MSSVs (2MS-0001, 2MS-0005, 2MS-0013, and 2MS-0014) were improperly installed on May 4-5, 1996. Associated Maintenance Procedure MP/0/A/1200/089, Valve - Main Steam Safety - Setpoint Test, Step 12.3 states that, "Spindle nut cotter pins are in place and in good mechanical condition." The inspector noted that there was no documented QC or second party verification to ensure correct cotter pin installation. The failure of Maintenance personnel to properly install the subject cotter pins per MP/0/A/1200/089 is considered a violation of TS 6.4.1 and is identified as example one of Apparent Violation (EEI) 50-270,287/96-16-05: Failure to Properly Install MSSV Spindle Nut Cotter Pins.

The two Unit 3 MSSVs (3MS-0001 and 3MS-0010) which had missing cotter pins should have had the pins installed during the performance of MP/0/A/1200/089 on July 17-18, 1996. The failure of Maintenance personnel to properly install the subject cotter pins per MP/0/A/1200/089 is considered a violation of TS 6.4.1 and is identified as example two of Apparent Violation (EEI) 50-270,287/96-16-05: Failure to Properly Install MSSV Spindle Nut Cotter Pins.

The licensee's proposed corrective action was to perform minor modifications on all three units' MSSVs to remove the lift lever assembly (i.e., lift lever, lever pin, lever cotter pin, forked lever, forked lever pin, forked lever cotter pin, spindle nut, and spindle nut cotter pin). The inspector verified that WO96083643, WO96083248, and WO 96083850 were being generated, and will be implemented during the ongoing outages. The inspector also reviewed the safety evaluations associated with the lift lever assemblies and did not identify any additional issues of concern.

c. Conclusion

Maintenance personnel failed to appropriately implement the procedure requirements for restoration of the MSSVs by ensuring that cotter pins were properly installed on two Unit 3 MSSVs and four Unit 2 MSSVs. These examples of poor Maintenance performance could have led to entry into Emergency Operating Procedures and/or loss of OTSGs as decay heat removal paths. Accordingly, an Apparent Violation with two examples was identified.

M8 **Miscellaneous Maintenance Issues** (92903)

M8.1 (Closed) IFI 269,270,287/96-12-01 MSSV Cotter Pin Inspection

This item is closed based on the information provided in Section M4.2 of this inspection report.

M8.2 (Open) Unresolved Item 269/96-04-04 Root Cause Assessment of Failures to Valves 1MS-77 and 1LPSW-254

One of the two issues addressed by this item involved unreliability of valve 1LPSW-254. The valve is in the Low Pressure Service Water (LPSW) system and is the Unit 1 Train A Low Pressure Injection (LPI) Cooler outlet isolation valve. Valve 1LPSW-251 is the LPI cooler outlet flow control and is located directly upstream of 1LPSW-254. As documented in NRC Inspection Report 50-269,270,287/96-04, piping vibration in the vicinity of these valves has caused failures of valve 1LPSW-254 in the past. A modification was implemented in 1992 in an attempt to improve reliability; however, there have been subsequent failures. Each train of LPI on all three units has a similar arrangement. The unresolved item was opened pending the licensee's evaluation of the vibration problem and determination of necessary corrective actions.

During this inspection period, the A train of LPI was placed in service for decay heat removal following shutdown of Unit 1. In service inspections of the valve were performed by engineering personnel. As documented in PIP 1-096-2000, on October 11 slight motion of the 1LPSW-254 valve stem relative to the operator was identified. On October 12 corrective maintenance was performed to replace the key (which showed signs of wear) and the operator was rotated 180° to utilize the unused keyway in the operator drive sleeve. The A train of LPI was returned to service following testing later the same day. On October 15, a followup inspection of the valve by engineering personnel identified a crack in the valve stem at the key way. The A train of LPI was removed from service and a temporary modification was initiated to remove the valve from the system. The inspector observed the work to implement the modification as documented in Section M1.2. of this report.
Since unreliability of valve 1LPSW-254 continued, the inspector reviewed the status of Unresolved Item 269/96-04-04. The licensee had completed the engineering evaluation of the system vibration in the vicinity of the LPI cooler flow control valves, including an initial recommendation for corrective action.

The results of the vibration evaluation were documented in an engineering memo to file dated October 1, 1996. The evaluation indicated that excessive vibration existed in the LPSW LPI cooler flow control valves on all three units. The vibration is the result of flow induced cavitation through the flow control valves. Valve 1LPSW-254 is the shortest distance downstream from its associated flow control valve. This has likely contributed to its higher rate of failure. The engineering evaluation recommended replacement of the flow control valves with larger valves that included a flow attenuator and the replacement of the isolation valves with larger valves of the same style.

Additional corrective actions for the 1 LPSW-264 failures are still under review by station management. The failure of 1MS-77 was not reviewed. The URI remains open.

III. Engineering

E1 Conduct of Engineering

E1.1 3B Main Feedwater Pump (MFP) Gear Failure

a. Inspection Scope

The inspector reviewed the licensee's root cause evaluation and PIPs associated with the 3B MFP failure which occurred on August 24, 1996.

b. Observations and Findings

On August 24, 1996, Unit 3 experienced a runback to 65% power due to a loss of the 3B MFP. The licensee determined that the runback was caused by a failure of the 3B MFP turbine main shaft oil pump (MSOP) to function because of the failure of the number three and number four gear set. The actual root cause of the gear failures is still under evaluation. As documented in PIP 3-096-1626, part of the assessment of the failure addressed whether the failed gears were a matched pair, or not. Previous failures dating back to 1994 had identified this as a problem. The licensee's investigation revealed that the gears that were replaced were a matched pair but that it was fortuitous and not because of corrective actions from previous events. PIP 2-094-474 provided guidance to purchase the gears in matched sets. Due to a lack of communication, the gears that were already purchased were not returned, and no matched pairs were ever ordered. Currently, there is an active purchase identification number for matched gear sets.

Since the late 1980s the licensee had performed major Preventive Maintenance (PM) on the MFPs every refueling outage (RFO). On October 4, 1994, the licensee changed the major PM to every third RFO and minor PM to every RFO. On July 25, 1995, the licensee changed the major PM to every fourth RFO to coincide with MFP rebuild. After this latest failure, the licensee revised the PM frequency on the MFP front standard hydraulic system to once per refueling outage until a cost benefit analysis can be performed on the available MSOP reliability improvement options.

The inspectors observed the 3B MFP being rebuilt with the new gears. The licensee conducted the work with appropriate WOs and procedures.

c. Conclusion

The licensee's corrective actions were appropriate to address this issue.

E1.2 Letdown Storage Tank Level Redundant Power Supply

a. Inspection Scope (37551)

The inspector reviewed the circumstances leading to the identification that the Letdown Storage Tank (LDST) level instrumentation was not powered from a redundant power supply.

b. Observations and Findings

On October 28, 1996, the licensee identified that Unit 3 LDST level transmitter ON3HPILT0033P1 was not powered from the Integrated Control System (ICS) Redundant Power Panel. Further investigation revealed that Unit 1 was also not powered from the Redundant Power Panel.

A modification, NSM 1,2,3 2728 had been implemented in the 1989 and 1990 time period which changed the transmitters from Bailey to Rosemount types. During the modification, the redundant power supply detailed on drawings had not been reconnected on Units 1 and 3, but was properly installed on the Unit 2 instruments. IP/0/A/0202/1F, HPI LDST Level Instrument Calibration Procedure, was performed as a post modification test. The test did not address the redundant power supply.

The inspectors reviewed applicable Bailey Meter Company instrument drawing D80323245, Rev. DQ (drawing referenced the Rosemount Instruments) and verified that the field installation was not in accordance with the drawing. The consequences of a power failure to the LDST Level instrumentation was discussed with the system engineer. A power failure to the instrument would result in the indication dropping to mid-scale. This mid-scale instrument failure would be less noticeable than a failure to the low-end of the scale. However, in reviewing the control room indication, it was learned that there was a light on the face of the gage which would go out if power failed. It was further observed that the normal operating range was at approximately 90 percent of full scale and a failure to the 50 percent position should be detected by the operators. The inspector concluded that should the single power source fail, Operations would have detected the failure within a short period of time.

The licensee issued PIP 0-96-2165 to describe and resolve this problem. Additionally, they aggressively initiated corrective action. The licensee has reconnected the redundant power supply on Unit 1 instruments and has scheduled the work on Unit 3 to be performed prior to its restart. The inspector reviewed the Unit 1 re-installation functional test data and had no further concerns.

c. Conclusion

Although the LDST indication is not considered safety-related, the indication is essential (importatant to safety) to ensure that the plant

is operated in a safe manner. Failure to maintain plant configuration as detailed on the drawings is a violation. This licensee identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. This issue will be identified as NCV 269,287/96-16-04, Failure to Maintain Equipment in Accordance with Plant Drawings.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Unresolved Item (URI) 50-269,270,287/96-12-02 LDST Pressure-Level Curves

The licensee determined that LDST level calibration procedure IP/0/B/0202/001F, Letdown Storage Tank Level vs. Pressure Curve Limits, did not properly account for instrument uncertainties. The procedure was in error because a specific gravity correction factor had been misapplied in calculation OSC-4506, Letdown Storage Tank Level Instrument Loop Accuracy Calculation For 1, 2, 3 HPILT0033P1 and 33P2. The inspector concluded that calibration procedure IP/0/B/0202/001F was inadequate, in that it did not correctly account for instrument uncertainties, and is being identified as Violation 50-296,270,287/96-16-02, LDST Calibration Procedure In Error.

As described in IR 50-269,270,287/96-12, there was no present operability concern. The inspector reviewed calculation OSC-6646, Past Operability Determination For PIPs 0-096-1539 and 0-096-1550, LDST Curve Analysis. Calculation OSC-4616 determined the curves for operations use in maintaining the correct level pressure relationship in the LDST to ensure that gas would not be carried into the suction of the HPI pumps. Non-conservatisms were noted in OSC-4616. Specifically, the partial pressures of gas and water vapor had not been considered in the calculation. OSC-6646 examined the results of OSC-4616 and previous revisions of the curves that had been used at ONS. The results of this calculation were that all points, except one at 92 inches (outside the normal operating range), were bounded by the data sheets of the previous calculations. The calculation concluded that there were some extremely remote conditions (i.e., elevated BWST temperature) that may not have been bounded. However these conditions were considered not to be credible. Accordingly, URI 50-269,270,287/96-12-02 is closed.

IV.Plant Support Areas:

R1 Radiological Protection and Chemistry (RP&C) Controls (71750)

R1.1 Transportation of Radioactive Materials

a. Inspection Scope (86750, TI2515/133)

The inspectors evaluated the licensee's transportation of radioactive materials program for implementing the revised Department of

Transportation (DOT) and NRC transportation regulations for shipment of radioactive materials as required by 10 Code of Federal Regulations (CFR) Part 71 and 49 CFR Parts 100 through 177.

b. Observations and Findings

The inspectors reviewed procedures and determined that they adequately addressed: assuring that the receiver has a license to receive the material being shipped; assigning the form, quantity type, and proper shipping name of the material to be shipped; classifying waste destined for burial; selecting the type of package required; labeling and marking the package; placarding the vehicle; assuring that the radiation and contamination limits are met; and preparing shipping papers.

The inspectors reviewed the licensee's records for 15 shipments of radioactive material and determined the shipping papers contained the required information. The licensee was maintaining records of shipments of licensed material for a period of three years after shipment as required by 10 CFR 71.91(a). Certificates of Compliance (CoC) for the shipping casks the licensee currently used were reviewed and the inspectors determined that the CoCs were currently NRC approved for use.

A review of the licensee's computer software for classifying waste shipments indicated that it had been updated to reflect the latest DOT isotopic concentration changes in the A1 and A2 shipping table values.

c. Conclusions

Based on the above reviews, it was concluded that the licensee had effectively implemented a program for transporting radioactive materials and for classifying waste destined for burial.

R1.2 Water Chemistry Controls

a. Inspection Scope (84750)

The inspectors reviewed implementation of selected elements of the licensee's water chemistry control program for monitoring primary and secondary water quality. The review included examination of program guidance, as well as implementing procedures and analytical results for selected chemistry parameters.

b. Observations and Findings

The inspectors reviewed Technical Specification (TS) 4.1.3, which described the operational and surveillance requirements for reactor coolant activity and chemistry. The inspector also reviewed Final Safety Analysis Report (FSAR) Sections 5.2.1.7 and 9.3.1.2, which indicated guidelines for maintaining reactor coolant and feedwater quality that were derived from vendor recommendations and the current

revisions of the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) Primary and Secondary Water Chemistry Guidelines. The FSAR also indicated that detailed operating specifications for the chemistry of those systems were addressed in the Chemistry Section Manual.

The inspector reviewed selected analytical results recorded for Units 1, 2, and 3 reactor coolant and secondary samples taken during June 1, 1996, and October 19, 1996. The selected parameters reviewed for primary chemistry included pH, dissolved oxygen, chloride, fluoride, and sulfate. The selected parameters reviewed for secondary chemistry included pH, dissolved oxygen, fluoride, and chloride. Those primary and secondary parameters reviewed were maintained well within the relevant TS limits and within the EPRI guidelines for power operations and cold shutdown modes for PWR primary water chemistry.

c. Conclusions

Based on the above reviews, it was concluded that the licensee's water chemistry control program for monitoring primary and secondary water quality had been implemented in accordance with the TS requirements and the EPRI guidelines for PWR water chemistry.

R2 Status of Radiation Protection Facilities and Equipment

R2.1 Process and Effluent Radiation Monitors

a. Inspection Scope (84750)

The inspectors reviewed selected licensee procedures and records for required surveillances on process and effluent radiation monitors and for radiation monitor availability.

b. Observations and Findings

The inspectors toured the facility and observed the physical operation of radiation monitors in use. Radiation monitor local digital displays were compared to control room monitor displays for ten radiation monitor displays. The displays were determined to be tracking consistently with each other. The inspectors also reviewed selected surveillance procedures and records for performance of channel checks, source checks, channel calibrations, and channel operational tests for the radiation monitors listed below:

RIA-39	Control room ventilation monitor
RIA-41	Spent fuel building ventilation monitor
3RIA-41	Spent fuel building ventilation monitor
1RIA-43	Unit 1 ventilation monitors
1RIA-44	Unit 1 ventilation monitors
1RIA-45	Unit 1 ventilation monitors

1RIA-46	Unit 1 ventilation monitors
1RIA-47	Reactor building airborne monitoring system
1RIA-48	Reactor building airborne monitoring system
1RIA-49	Reactor building airborne monitoring system
1RIA-49A	Reactor building airborne monitoring system

Surveillance testing was required by the TSs and/or the Offsite Dose Calculation Manual (ODCM) to demonstrate that the instrumentation was operable. Records indicated that the surveillances were current and had been performed in accordance with the applicable procedures. The most recent system status report available, which covered the period January through June 1996, indicated that the overall availability for the Radiation Monitoring System remained above 99 percent. The inspectors discussed operability trending methods for both safety-related and nonsafety-related monitors with the radiation monitor system engineer in addition to reviewing spare parts inventory data. Operability records reviewed and discussed with cognizant licensee personnel indicated that one containment high range monitor had previously been out of service for a period of 25 days as a result of spare parts availability problems.

c. Conclusions

Based on the above reviews, it was concluded that the licensee had effectively implemented procedures to track the availability of radiation monitors and to demonstrate operability of process and effluent radiation monitors by performance of surveillances at the frequencies specified in the TSs and the ODCM. Discussions with cognizant licensee personnel and a review of performance records determined the licensee was maintaining an overall high level of operability for radiation monitors in the first six months of 1996.

R5 Staff Training and Qualification in Radiation Protection and Chemistry

R5.1 Training for Transportation of Radioactive Material

a. Inspection Scope (86750, TI 2515/133)

The inspectors reviewed training for personnel and supervisors involved in transportation of radioactive material.

b. Observations and Findings

The inspector reviewed licensee training records and verified that personnel involved with radioactive material shipping were maintaining current hazardous material (HAZMAT) training qualifications.

c. Conclusions

The inspectors determined the licensee's training program associated with transportation of radioactive material was adequate. The inspectors concluded the transportation training focused on good radiological control work practices and compliance with transportation regulations.

R7 Quality Assurance in Radiation Protection and Chemistry Activities

R7.1 Review of RP&C Self-Assessment Activities

a. Inspection Scope (84750, 86750, TI 2515/133)

The inspectors reviewed a licensee self-assessment and discussed issues identified with licensee management to determine if the licensee was identifying issues of substance, proposing corrective actions, and tracking items for completion in the areas inspected.

b. Observations and Findings

The assessment, Regulatory Audit SA-96-39(ON)(RA), dated August 27, 1996, was conducted during the period of July 22, 1996, through July 30, 1996, at the Oconee Nuclear Site. The scope of the assessment was in the areas of chemistry, radiation protection, and transportation of radioactive material program activities. A number of substantive issues were identified by the audits and were characterized as either findings, followup items, strengths, weaknesses, recommendations, or observations. Pursuant to the licensee's auditing procedures, the identified issues, including corrective actions for the findings, were tracked for completion of warranted followup actions by initiating PIPs. The inspector determined that the audits were of sufficient scope and depth to identify existing problems and that corrective actions for the identified findings were documented and resolved through the PIP. The audit results were well documented and reported to facility management in a timely manner.

c. Conclusions

Based on the above reviews, it was concluded that the licensee had complied with the TS required program for conducting assessments of station activities.

P3 Emergency Preparedness Procedures and Documentation.

P3.1 Emergency Preparedness Followup to Licensee Event (Unit 2)

a. Inspection Scope (71750)

The inspectors reviewed the declaration and termination actions taken by the licensee for the licensee's Notice of an Unusual Event (NOUE) associated with a Unit 2 secondary side steam line break to verify the licensee complied with their Emergency Coordinator procedures for event classification.

b. Observations and Findings

The inspectors verified the event was classified in accordance with licensee procedure RP/O/B/1000/01, Emergency Classification, Change 3, dated July 16, 1996. The licensee classified this event as an Unusual Event based on emergency action levels (EALs) identified in the procedure.

The Event Notification form reviewed by the inspectors, verified the event was declared and terminated at 8:40 p.m. on September 24, 1996, from the Technical Support Center (TSC). During the event debrief, the licensee identified that the Emergency Coordinator procedure did not contain adequate guidance for event declarations and termination. Specifically, an event checklist used in the Control Room and Emergency Operating Facility (EOF) for terminating an event was not available in the TSC Emergency Coordinator procedure. The licensee initiated a Problem Investigation Process (PIP) report to evaluate the problem and completed a procedural revision for the Emergency Coordinator TSC procedure to provide procedural guidance for terminating a NOUE consistent with the guidance in the control room and EOF procedures. The inspector had also identified that the procedure used in the TSC during the event was not adequate for terminating an Unusual Event. The inspector informed the licensee that this was a violation of TS 6.4.1 which required written procedures with appropriate instructions and check-off list shall be provided. The inspector noted that the licensee took immediate corrective actions to upgrade the TSC procedure. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This issue is identified as NCV 50-269,270,287/96-16-03, Failure to Provide Adequate Procedural Guidance in the TSC for Exiting a NOUE.

c. Conclusions

Based on an independent review of records, logs, and interviews with personnel involved with the event, the inspectors verified the event was classified in accordance with licensee procedures. However, the licensee terminated the event without adequate procedural guidance in the TSC. Accordingly, an NCV was identified for this licensee-identified violation.

X1. Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 20, 1996. The licensee acknowledged the findings presented.

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

Partial List of Persons Contacted

Licensee

B. Peele, Station Manager
E. Burchfield, Regulatory Compliance Manager
D. Coyle, Systems Engineering Manager
T. Curtis, Operations Manager
J. Davis, Engineering Manager
T. Coutu, Operations Support Manager
W. Foster, Safety Assurance Manager
J. Hampton, Vice President, Oconee Site
G. Hamrick, Manager, Chemistry
D. Hubbard, Maintenance Superintendent
C. Little, Electrical Systems/Equipment Manager
J. Smith, Regulatory Compliance
J. Twiggs, Manager, Radiation Protection

NRC
D. LaBarge, Project Manager

Inspection Procedures Used

IP 55050:	Nuclear Welding
IP 71750:	Plant Support Activities
IP 71707:	Plant Operations
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 37551:	Onsite Engineering
IP 92901:	Followup - Plant Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92700:	Onsite LER Followup
IP 73753:	Inservice Inspection
IP 84750:	Radioactive Waste Treatment, Effluent Environmental Monitoring
IP 86750:	Solid Radioactive Waste Management Transportation of Radioactive Materials
IP 71001:	Licensed Operator Requalification Program Evaluation
IP 71714:	Cold Weather Preparations
IP 62703:	Maintenance Observations
IP 40500:	Effectiveness of Identification and Resolving Problems
TI 2515/133:	Implementation of Revised 49 CFR Parts 100-177 AND 10 CFR Part 71

Items Opened, Closed, and Discussed

Opened

50-269,270/96-16-01	VIO	Maintenance Failed To Initiate A PIP (Section M4.1)
50-296,270,287/96-16-02	VIO	LDST Calibration Procedure In Error (Section E8.1)
50-269,270,287/96-16-03	NCV	Failure to Provide Adequate Procedural Guidance in the TSC Exiting a NOUE (Section P3.1)
50-269,287/96-16-04	NCV	Failure to Maintain Equipment in Accordance with Plant Drawings (Section E1.2)
50-270,287/96-16-05	EEI	Failure to Properly Install MSSV Spindle Nut Cotter Pins (Section M4.2)
50-287/96-16-06	IFI	ICS Malfunction Training Results (Section O5.1)

Closed

50-270/96-12-04	URI	Pressurizer Safety Valve 2RC-67 Operability (Section O8.1)
50-270/96-12-03	URI	Delay In LER Submittal (Section O8.2)
50-270/96-03	LER	Pressurizer Relief Valve Technically Inoperable (Section O8.3)
50-269,270,287/96-12-02	URI	Letdown Storage Tank Pressure-Level Curves (Section E8.1)
50-269,270,287/96-12-01	URI	MSSV Cotter Pin Inspection (Section M8.1)

Discussed

50-269/96-04-04	URI	Root Cause Assessments of Failures to Valves IMS-77 and 1LPSW-254 (Section M8.2)

List of Acronyms

ABVS	Auxilary Building Ventilation System
ANI	American Nuclear Insurance
ANSI	American Nuclear Society Institute
ASME	American Society of Mechanical Engineers
BWST	Borated Water Storage Tank
CFR	Code of Federal Regulations
CC	Component Cooling
CCW	Condenser Circulating Water
CoC	Certificates of Compliance
CR	Control Room
CRDM	Control Rod Drive Mechanism
DOT	Department of Transportation
DPC	Duke Power Company
EAL	Emergency Action List
ECCS	Emergency Core Cooling System
EEI	Apparent Violation
EFW	Emergency Feedwater
EOC	End Of Cycle
EOF	Emergency Operating Facility
EPRI	Electric Power Research Institute
EWST	Emergency Water Storage Tank
FWDS	Field Weld Data Sheet
FSAR	Final Safety Analysis Report
GPM	Gallons Per Minute
HAZMAT	Hazardous Material
H/L	Hot Leg
HP	Health Physics
HPI	High Pressure Injection
ICS	Integrated Control System
I&E	Instrument & Electrical
IR	Inspection Report
ISI	Inservice Inspection
KHU	Keowee Hydro Unit
LDST	Letdown Storage Tank
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MFP	Main Feedwater Pump
MRPC	Motorized Pancake Coil
MSOP	Main Shaft Oil Pump
MSSV	Main Steam Safety Valve
MP	Maintenance Procedure
MVA	Mega Volts-Amps
MW	Megawatts
NCV	Non-Cited Violation

NDE	Non-Destructive Examination
NLO	Non-Licensed Operator
NOUE	Notice Of Unusual Event
NRC	Nuclear Regulatory Commission
NSM	Nuclear Station Modification
NSD	Nuclear System Directive
ODCM	Offsite Dose Calculation Manual
ONS	Oconee Nuclear Station
OTSG	Once Through Steam Generator
PRVS	Penetration Room Ventilation System
PSIG	Pounds Per Square Inch Gauge
PSV	Pressurizer Safety Valve
pH	Conductivity
PIP	Problem Investigation Process
PM	Preventive Maintenance
PRVS	Penetration Room Ventilation System
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QC	Quality Control
RBV	Reactor Building Ventilation
RCS	Reactor Coolant System
RFO	Refueling Outage
RIA	Radiation Instrument Area
RP&C	Radiological Protection & Chemistry
RPS	Reactor Protection System
RTD	Resistance Temperature Detector
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order
WR	Work Request