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Licensee: Duke Energy Corporation

Facility: Oconee Nuclear Station, Units 1, 2, and 3

Location: 7812B Rochester Highway
Seneca, SC 29672

Dates: December 28, 1997 - February 7, 1998

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Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/97-18,
50-270/97-18, 50-287/97-18

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection, and the results of announced inspections by three regional based inspectors.

Operations

- Operations personnel satisfactorily shut down Unit 1 following a steam generator tube leak. The licensee identified a related procedure problem that resulted in a Non-Cited Violation. Operations satisfactorily performed the shutdown and overall once through steam generator configuration control work. The licensee drained the reactor coolant system in a controlled fashion to reduced inventory levels five times during the work. This problem is also discussed in Section M1.4. (Section O1.3)

- Operations personnel displayed a good questioning attitude that allowed them to detect an unexpected power increase during letdown flow instrument calibrations. This problem is also discussed in Section M3.1. (Section O1.4)

- The licensee exited a 24-hour limiting condition for operation on the Unit 3 reactor building emergency hatch without fully understanding that a Technical Specification interpretation did not relieve them of the surveillance requirements for further testing. This issue was left unresolved pending review of past practices. (Section O1.5)

- The licensee carefully tested and satisfactorily replaced a Unit 1 control rod, which had latching problems. Operations and engineering provided good overall controls during the rod freedom of motion test. (Section O1.6)

- Operations satisfactorily manipulated Unit 1 to cold shutdown for repairs and investigation of a 2 gallon per minute leak from a crack on a one-inch drain line off the pressurizer surge line. Operations made appropriate notifications and reports. (Section O1.7)

- An apparent lack of agreement between the Safe Shutdown Facility diesel technical manual and operations procedures will be tracked through an unresolved item. (Section O3.1)

- The licensee and its primary vendor removed and disassembled a malfunctioning Unit 1 control rod mechanism, finding no definitive problem. The overall inspection work was performed in a satisfactory manner, with care to detect as-found conditions. (Section M1.2)
- During the pressurizer surge line drain line work, pipe removal and reinstallation practices and controls were generally acceptable. Health physics personnel appropriately supported the maintenance activities. One rework item was observed that is discussed as a violation in Inspection Report 50-269,270,287/98-01. (Section M1.3)

- The December 28, 1997, Unit 1 shutdown for primary-to-secondary leakage that was the result of past repairs where there had been an apparent over-reliance on the results of visual inspections, and less than adequate appreciation for primary water stress corrosion cracking. (Section M1.4)

- A violation was identified for failure to revise a high pressure injection system letdown flow instrument calibration procedure following modification of the Unit 3 integrated control system. (Section M3.1)

- During inspection and testing of Safe Shutdown Facility 600 volt breakers, several problems were identified by the licensee. The licensee satisfactorily addressed the immediate equipment problems. Several issues regarding grease hardening and trip device past operability were identified. (Section M3.2)

- On January 30, 1998, the licensee was granted verbal enforcement discretion on statements in their TS regarding TS surveillance performance intervals. The licensee submitted a TS change to allow eighteen-month periodicity of surveillance instead of a refueling outage periodicity. The inspectors had reviewed the change for completeness. Additional followup on the enforcement discretion will be tracked under an unresolved item. (Section X2)

Engineering

- Replacement of the cracked one-inch drain line on the pressurizer surge line was consistent with applicable code requirements. A lack of attention to detail in the planning phase of welding the replacement line caused a significant job delay and the need to cut and re-weld a new weld on the line. Engineering provided adequate support and took an active role in determining the root cause of the crack. Welding, nondestructive examination, and process control activities were satisfactory. Stress analysis calculations determined that thermal stratification and hanger loads on the drain line exceeded code allowable usage factor requirements on the drain line nozzle. (Section E1.1)

- Three examples of a violation resulting from procedural inadequacies were identified. An engineering supported troubleshooting procedure did not minimize risk to equipment and was not completely validated prior to performing work. Use of the procedure on Unit 2 integrated control

system wiring resulted in unexpected system responses. The other two examples are discussed in Section E2.2. (Section E2.1)

- Two additional examples of the violation resulting from procedural inadequacies were identified on the Keowee Hydroelectric units. One example involved the motor operated automatic voltage adjusters on both Keowee units not being adjusted in accordance with their applicable drawings due to lack of procedural detail. The other example involved missed in-service tests on both Keowee Hydroelectric units due to engineering not converting a temporary test into a periodic test of lube oil valves. (Section E2.2)

- A Non-Cited Violation was identified for failure to follow procedures controlling modifications as discussed in Licensee Event Report 50-269/97-10, regarding reactor building sump issues. (Section E8.1)

- The licensee was making good progress in the installation of the service water modifications. Modifications on Unit 2 should be completed during the March 1998 outage. (Section E8.2)

Plant Support

- A Non-Cited Violation was identified for failure to perform a continuous fire watch as required by the selected license commitments. The licensee had performed hourly fire watches instead of continuous fire watches when they removed the Unit 2 and 3 startup transformers fire protection deluge system from service. (Section F1.1)

Report Details

Summary of Plant Status

Unit 1 began the report period at approximately 54 percent power, performing integrated control system testing. On December 28, 1997, the unit began required shutdown activities following the identification of a primary-to-secondary leak. During the heat up following completion of inspection and repairs to both steam generators, a leak was identified on the pressurizer surge line drain. At the end of the report period, the unit was in cold shutdown.

Unit 2 began and ended the report period at 100 percent power.

Unit 3 began and ended the report period at 100 percent power.

Review of Updated Final Safety Analysis Report (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 parameters.

I. Operations

O1 Conduct of Operations

O1.1 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.

O1.2 Operations Clearances (71707)

The inspectors reviewed the following clearances during the inspection period:

- 97-4445 Unit 3 Seal Supply Filter Swap
- 98-0207 Unit 1 Component Cooling Water Cooler

The inspectors observed that the clearances were properly prepared and authorized and that the tagged components were in the required positions with the appropriate tags in place.

O1.3 Unit 1 Once Through Steam Generators (OTSG) 1A Tube End Weld Leaks

a. Inspection Scope (71707, 93702)

On December 28, 1997, the licensee detected radioisotopes in the secondary system of Unit 1. The unit was at 54 percent power conducting a power escalation following the refueling outage. The licensee

initiated a controlled shutdown and Problem Investigation Process (PIP) report 1-97-4641 (with a failure investigation process team). The inspectors observed the controlled shutdown of the unit, the once through steam generator (OTSG) work, and subsequent return of the unit to service. The inspectors also reviewed Licensee Event Report 97-11 written to document the event. A regional inspector was detailed to the site in order to follow the repairs. Section M1.4 addresses nondestructive inspections and engineering details of the problem and related repairs.

b. Observations and Findings

Sequence of Events

On December 27, 1997, the licensee completed an integrated control system (ICS) load rejection test from approximately 25 percent power. About one hour after the end of the ICS test segment, radiation process monitor RIA-40 for the condenser steam air ejectors went into alarm. Following the guidance of PT/O/A/0230/01, Radiation Monitor Check, Revision 109C, operations reset the RIA-40 alert alarm setpoint at twice background level. However, the operations crew involved overlooked a note on the next page of the procedure which indicated that if RIA-40 alarmed, samples should be taken to verify the leak rate. At shift turnover the next morning, the shift discussed the reset of RIA-40. The oncoming operators indicated that a sample was needed, and one was subsequently taken at 8:08 a.m., on December 28, 1997. Confirmatory samples in the afternoon of that same day confirmed a tube leak. The licensee then entered the emergency operating procedure for an OTSG tube leak. At 3:07 p.m. a unit shutdown was initiated. At 3:32 p.m. the licensee completed a 10 CFR 50.72 notification to the NRC duty officer. The unit was off line at 4:46 p.m.

Tube Leak Detection

The first indication of the primary-to-secondary leak was on the condenser steam air ejector radiation monitor. At the time of the RIA-40 alarm and reset on December 27, 1997, historical trend data indicated small but progressive increases in radiation levels. Additionally, the RIA-16 (1A main steam line) monitor did trend up slightly, but did not reach the alarm setpoint (2.5 millirem (mr) per hour setpoint with a maximum attained value of slightly higher than 0.06 mr per hour).

The inspectors were informed that radiation instruments such as the condenser steam air ejector monitor, will show increases in background and may show small spikes due to power changes and material releases from deposits in the secondary breaking loose. The inspectors were also informed that historically during startups, RIA-40 required a reset of its setpoint to compensate for normal background increases.

Due to the low radiation levels, the leak was not readily detectable. Although secondary off-gas process monitoring is generally the first indication of an OTSG tube leak, the small size of the 1A OTSG leak and the minimal isotopic migration to the secondary made this leak

particularly difficult to detect. The leakage was relatively free of isotopes due to the recently refueled core, overall cleanliness of the primary, and limited size of the leak.

Likewise, the chemistry department could not positively identify a leak with the 8:00 a.m. samples, but similarly could not disprove its presence. The xenon isotope was in low concentration in the primary. The licensee used the minimum detectable limit, an artificial number, for the isotopic concentration in the leakage rate calculation. This calculation produced an initial leak rate of 260 gallons per day (gpd) following the first sample.

RIA-16 for the 1A steam line indicated an increasing trend. The RIA-17 monitor for the 1B steam line was flat-lined. Given this and the inability to disprove a leak, the licensee drew a second series of samples and analyzed them in the early afternoon (there was a 90 minute sample preparation time). As the power was increased by the time of the second sample, the xenon isotope in the primary was elevated and slightly above the minimum detectable level. The licensee introduced this value into the leak rate calculation which resulted in a higher leak rate of 404 gpd. With the low isotopic levels in the primary and the change in power, the licensee believed that there was no true increase in the leakage rate between the 8:00 and 11:00 a.m. samples. At that point, with no radiation process monitors in an alarm state, the licensee decided to shut down the unit. The secondary and turbine building sumps received very small increases in radiation levels.

The inspectors determined that had primary and secondary chemistry samples been drawn at the time of the initial RIA-40 alarm, it was inconclusive that the licensee would have detected the leak since there was very little radiation specie concentration in the secondary.

Adequacy of Radiation Monitor Procedure

The inspectors reviewed the RIA-40 instructions contained in Procedure PT/0/A/0230/01 and observed that they were not adequate from two perspectives. First, the requirement for sampling was contained in the "notes" of the procedure outside the procedural text. Second, the direction to take samples contained a "should" statement.

The subject procedure was not adequate in that policy intent or prudent requirements were not positively and clearly stated as required in Nuclear Site Directive 703, Administrative Instructions for Site Procedures, revision date December 30, 1997, Section 703.5, Preparation of Procedures. Subsection 4 of the directive indicated, in part, "That all instructions should be clear and precise. Ambiguous and vague wording or implied action should be eliminated from the procedure." Additionally, Regulatory Guide 1.33, Revision 2, which is invoked under the licensee's topical report, states that "shall" statements are to be used instead of "should" statements where the procedural step is of sufficient importance. Operations management stated policy was to take the samples with an alarm of RIA-40.

An operations management review of the tube leak events on or before January 8, 1998 (prior to LER issuance), initiated correction actions to be available for the next startup and normal plant operation. Operations, in conjunction with Chemistry, performed the following corrective actions: (1) discussed the sampling expectations with the operations crew of December 27, 1997; (2) provided the sampling expectations to the other operational shifts; (3) incorporated what had been notes in the previous revision of PT/0/A/0230/01 as requirements and added enhancements in the reset of RIA-40; (4) changed annunciator response Procedure 1SA-8/D-10, Radiation Monitoring, to clearly state samples were to be taken by chemistry when RIA-40 went into alarm (instead of referring to another complex document); (5) rewrote Procedure OP/0/A/1106/31, Control of Secondary Contamination, to enhance procedure usefulness and integration with the above PT. Inadequate Procedure PT/0/A/0230/01 was identified as a violation. This non-repetitive, licensee identified and corrected violation is identified as a Non-Cited Violation (NCV) consistent with Section VII.B.1 of the NRC Enforcement Policy, NCV 50-269/97-18-01: Inadequate RIA Procedure.

Performance of Operating Crews

The rapid shutdown of the unit following confirmation of the tube leakage on December 28, 1998, was well controlled by operations personnel.

Between January 1 and January 15, 1998, the unit was drained five times to reduced inventory levels. This was done to permit nozzle dam installation or removal in the Unit 1 OTSGs. An inspector was present for each of these draindowns, observing good control of the evolutions. With the number of draindowns performed, the licensee had reduced the activity to near routine, but retained the correct operational perspective. Control room operators provided oversight for tube sheet pressure tests that were similarly properly controlled.

c. Conclusions

Operations personnel satisfactorily shut down Unit 1 following a steam generator tube leak. The licensee identified a related procedure problem that resulted in a Non-Cited Violation. Operations satisfactorily performed the shutdown and overall once through steam generator configuration control work. The licensee drained the reactor coolant system in a controlled fashion to reduced inventory levels five times during the work.

O1.4 Unit 3 Power Change Due to Letdown Flow Calibration

a. Inspection Scope (71707)

The inspectors reviewed the operational aspects of an unexpected power increase on Unit 3. The maintenance controlled procedural aspects are discussed in Section M3.1.

b. Observations and Findings

On January 15, 1998, while Unit 3 was at 100 percent power and instrumentation technicians were calibrating letdown flow instrumentation, operations personnel observed a slight decrease in the core thermal power best one hour average and a slight increase in megawatt output.

Operations personnel notified reactor engineering, who identified that the letdown flow signal was an input to the thermal power calculation and that the thermal power calculation provided feedback to ICS. Following consultation with reactor engineering and completion of the evaluation, operations stopped the letdown flow calibration and reduced core thermal power demand by 0.2 percent.

When the letdown flow signal was set to zero during the calibration, core thermal power feedback to ICS decreased by 0.15 percent. In response, ICS adjusted feedwater flow enough to bring core thermal power back to 100 percent. However, since only the letdown signal was zero and not actual letdown flow, core thermal power never decreased and the adjustment by ICS caused actual core thermal power to exceed 100 percent. Licensee calculations determined that shift average power increased from 99.95 to 99.98 percent of rated power over an hour and a half period and that core thermal power reached a maximum of 100.10 percent of rated power. After reviewing TS and the reactor engineering power calculations, the inspectors determined that no power limits were exceeded.

c. Conclusions

Operations personnel displayed a good questioning attitude that allowed them to detect an unexpected power increase during letdown flow instrument calibrations.

01.5 Unit 3 Reactor Building (RB) Emergency Hatch

a. Inspection Scope (71707)

The inspectors reviewed the circumstances surrounding testing and operability of the Unit 3 RB Emergency Hatch.

b. Observations and Findings

On January 19, 1998, the licensee was performing Procedure PT/0/A/0150/08B, RB Emergency Hatch Leak Rate Test, Revision 25, and entered the hatch to remove strongbacks from the inner door as required by procedure. Upon exiting the hatch, the licensee found that the outer door would not close properly. The licensee declared the outer door inoperable and entered a 24-hour Limiting Condition for Operation in accordance with TS 3.6.3.a.

The licensee investigated the outer door and found that a small air pocket had been trapped behind the outer O-ring. Maintenance personnel

removed the air and closed the outer door properly. The licensee determined that no maintenance had been done; therefore, no further testing was required. Based on this, the licensee declared the outer door operable and exited TS 3.6.3.a.

Further investigation by the operations staff continued into January 20, 1998. On the next shift, the licensee determined that the hatch was inoperable due to an inoperable door gasket, and that a leak test of the outer door double seal was required. The licensee again declared the outer door inoperable and entered a seven-day LCO in accordance with TS 3.6.3.a.2. The licensee subsequently made the starting time for the LCO retroactive to the previous day when the hatch was originally declared inoperable. The licensee completed a test of the outer door O-rings using Procedure PT/0/A/0150/09A, RB Emergency Hatch Outer Door O-Ring Leak Rate Test, Revision 13. The outer door was subsequently declared operable and TS 3.6.3.a. was exited. The licensee documented the occurrence in PIP report 3-98-272.

The inspectors reviewed TS 3.6.3 and TS 4.4.1.5.2, reviewed control room and shift work manager logs, and interviewed personnel involved both in the maintenance of the door and in the initial decision to exit TS 3.6.3.a without performing any further testing. The inspectors determined that whether or not maintenance was performed did not affect the need for further testing. TS 4.4.1.5.2 stated that either a full hatch test or a leak test of the outer door double seal was required within three days of initial opening. The licensee had interpreted this TS to allow opening the outer door without further testing if the door was opened to remove strongbacks following a full hatch test. However, the inspectors determined the TS interpretation did not relieve the licensee of the surveillance requirement and therefore further testing was required.

The licensee did not violate any TS in this case because the door was reseated and tested within twenty-four hours. However, the existence of a TS interpretation indicated the outer door may have been opened in the past without proper surveillance testing. The circumstances surrounding this issue will be tracked as URI 50-287/97-18-02: Containment Air Lock Testing, pending review of past surveillance practices concerning containment air lock testing.

c. Conclusions

The licensee exited a 24-hour limiting condition for operation on the Unit 3 reactor building emergency hatch without fully understanding that a Technical Specification interpretation did not relieve them of the surveillance requirements for further testing. This issue was left unresolved pending review of past practices.

O1.6 Unit 1 Control Rod 7 of Group 5 Failure to Latch

a. Inspection Scope (71707, 93702, 37551, 92703)

On January 19, 1998, while performing a test, control rod 7 in group 5 would not withdraw in group control. The inspectors were immediately notified of the problem and followed the licensee's activities. This rod had a similar problem with operation on December 22, 1997, (Inspection Report 50-269,270,287/97-16, Section O1.5).

b. Observations and Findings

On January 19, 1998, at approximately midnight, while performing Procedure PT/0/A/305/01, Reactor Manual Trip Test, Revision 8, control rod 7 of group 5 would not respond to an out command. During the drop test done the previous day, the rod had operated normally. The licensee attempted to move the control rod by repeating activities done in December 1997, when the rod had exhibited out motion problems. The licensee's efforts, which included replacement of the control rod power cable, failed to restore function. Several days later, the plant was drained to a point above reduced inventory conditions (approximately 100 inches in the pressurizer) for replacement of the control rod drive (CRD). The inspectors observed the satisfactory drain, manual rod motion and freedom testing, removal of the CRD, and inspection of the CRD by the vendor (see Section M1.2). Operations and engineering provided good overall controls during the rod freedom of motion test. Unable to identify a cause for the rod motion problem, the licensee sent the mechanism to a vendor for further testing.

Retest of the new mechanism was satisfactory. The inspectors reviewed the test times, which were within the expected and TS values. The licensee subsequently continued preparations for unit startup.

c. Conclusions

The licensee carefully tested and satisfactorily replaced a Unit 1 control rod, which had latching problems. Operations and engineering provided good overall controls during the rod freedom of motion test.

O1.7 Oconee Unit 1 Cold Shutdown for Primary Leak

a. Inspection Scope (71707,93702,62707)

Following the completion of repairs to the CRD, the licensee discovered a small leak on the pressurizer surge line drain line. The licensee immediately notified the residents and NRC headquarters of the problem. The inspectors followed the recovery activities and repair efforts.

b. Observations and findings

Operations personnel had been warming Unit 1 to hot shutdown conditions. The plant was at 2100 psig and 500 degrees at midnight on January 26, 1998. Operations had observed an increase in the rate of normal sump

pumping. Reactor building leakage was estimated to be approximately 2.0 gpm. At midnight, a non-licensed operator (NLO) was sent into the RB to investigate the increased leakage. The operator found a weld area crack on a 90-degree elbow on the one-inch diameter pressurizer surge line drain that was spraying water vapor. The operator reported this information to the control room at 12:47 a.m. At 1:00 a.m., the licensee began a cooldown of the plant. For the observed conditions, the licensee entered the excessive leakage abnormal procedure and TS 3.1.6.3. At 1:10 a.m., operations notified the senior resident, who came to the site to review licensee actions. At 1:38 a.m., the licensee initiated a one-hour non-emergency phone call to the NRC's headquarters operations officer. The unit completed a normal cooldown over the remainder of the night with all observed parameters remaining within acceptable limits. The licensee initiated an investigation and an engineering manager was on site interviewing personnel by 3:00 a.m. At 5:00 a.m., the plant was at 550 psig and 337 degrees F with the licensee preparing to go on low temperature over pressure protection. The RB leakage trended down with RCS pressure. Based on personnel safety risks, the licensee made no further RB entries.

The plant was drained to above reduced inventory level to repair and investigate the weld problem over the next several days. The crack in the drain line was about 1/4 of the way around an elbow. This activity was well planned and supported by the investigative team direction. See Sections M1.3 and E1.1 for drain piping inspection details and repairs.

c. Conclusions

Operations satisfactorily manipulated Unit 1 to cold shutdown for repairs and investigation of a 2 gpm leak from a crack on a one-inch drain line off the pressurizer surge line. Operations made appropriate notifications and reports.

03 Operations Procedures and Documentation

03.1 Standby Shutdown Facility (SSF) Diesel Generator Operation

a. Inspection Scope (71707, 62707)

The inspectors observed the operation of the SSF diesel generator on February 6, 1998, during post-maintenance operation to return the SSF diesel generator back to service following scheduled maintenance.

b. Observations and Findings

During low idle maintenance operation, the licensee identified that turbo lube oil pressure was low on the A engine. Operations reviewed Procedure OP/0/A/600/10, Enclosure 4.5 SSF Diesel Generator Auto Idle Start, Revision 22, and contacted maintenance and engineering personnel nearby. While troubleshooting the low turbo oil pressure, maintenance identified that the installed engine revolutions per minute (rpm) tachometer was reading approximately 30 rpm low on hand-held calibrated

tachometers. The engine speed was less than the value stipulated in applicable operations procedure.

The system engineer identified that the operations procedure specified a different engine rpm value than the diesel technical manual. The technical manual stipulated an idle speed of 490 RPM. The operations procedure stipulated an idle speed of 400 - 450 RPM. Operations and system engineering continued to review the differences in the two procedures.

At the close of the inspection period, NRC review of the technical manual versus the operations procedure issue was not complete. Followup of this issue will be under Unresolved Item (URI) 50-269,270,287/97-18-03: SSF Diesel Generator Operation. This issue is unresolved pending additional NRC review of the maintenance and operations activities associated with the operation of the SSF diesel for return to service following maintenance.

c. Conclusions

An apparent lack of agreement between the SSF diesel technical manual and operations procedures resulted in an URI.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726)

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

•	WO 97053234	Change Out of Reactor Coolant Pump Seal Injection Filters
•	OP/3/A/1104/02	Enclosure 3.8, Swapping Seal Supply Filters, Revision 85C
•	PT/0/A/0620/09	Keowee Hydro Operation-Control Room Start, Revision 16
•	OP/1/A/1102/01	Controlling Procedure for Unit Start Up, Revision 218, Enclosure 4.18, Reactor Building Tour at Hot Shutdown
•	PT/1/A/0711/01	Zero Power Physics Testing, Revision 30, Enclosure 13.7, Approach to Criticality (Group 5, Rod 7 problem on January 22, 5:48 a.m.)
•	MP/1&2/A/1140/16	CRDM Shim Driver Removal and Replacement, Revision 3

- 5001137-00 Babcock and Wilcox Procedure, dated January 20, 1998, Type A Shim CRDM Refurbishment
- WO 97094576-1 Inspect Unit 1 Component Cooling Cooler Tubes
- WO 98009938 Inspect 2A Low Pressure Injection (LPI) Pump Boric Acid-Covered Casing Bolts
- IP/O/A/0305/01B Reactor Protection Systems (RPS) Channel B Pump Power Monitor Instrument Calibration, Revision 31
- IP/O/A/0305/015 RPS Removal From and Return to Service for Channel A,B,C,D, Revision 16
- PT/O/A/0610/22 Degraded Grid Switch Isolation and Keowee Overfrequency Functional Test, Revision 9
- OP/O/A/1600/10 Enclosure 4.5, SSF Diesel Generator Auto Idle Start, Revision 22
- P/O/A/1810/014 Valves and Piping-Welded-Removal and Replacement - Class A through F, Revision 26
- WO 97056137 Troubleshoot and Repair Unit 2 Integrated Control System
- PT/O/A/0610/22 Degraded Grid, Switchyard Isolation, and Keowee Overfrequency Protection, Revision 8
- TT/O/A/2200/16 Keowee Hydro Unit 2 Turbine Guide Bearing Oil System Test, Revision 1
- TT/O/A/0620/34 Keowee Emergency Blackout Start Test, Revision 0
- PT/3/A/0600/12 Turbine Driven Emergency Feedwater Pump, Revision 48

b. Observations and Findings

All work observed was performed with the work package present and in 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.

The inspectors were in the switchyard during the degraded grid test (PT/O/A/0610/22) observing proper operational configuration controls of the yard breakers and proper breaker operation. Operations personnel in the switchyard maintained good communications with the control room personnel and used good command and control techniques when talking with the test director.

During observations of the boric acid inspection (WO 98009938) in the 2A Low Pressure injection (LPI) pump room (63), the inspectors observed that Teflon tape was being used in several locations on the Unit 2 low pressure injection (LPI) system. Notably, the tape was used on pump casing plugs and system instrumentation connection points. Inspectors had also observed its use on the Unit 3 LPI system. Following inspector questions on this observation, the licensee commenced a detailed inspection observing the use of the Teflon tape in numerous locations on the systems and documented it in PIP report 2-98-455. The report indicated that piping specifications did not allow the use of the tape, but did not render the system inoperable. The tape was to be evaluated on a case by case basis with followup corrective actions. This finding was identified as URI 50-269,270,287/97-18-04: Teflon Tape Use on the LPI System.

c. Conclusions

The inspectors concluded that the maintenance activities listed above were generally completed thoroughly and professionally. One URI was initiated for the use of Teflon tape on the LPI system.

M1.2 Control Rod Drive Testing and Inspection

a. Inspection Scope (62707)

As indicated in Section O1.6, Group 5 Rod 7 had failed to latch on January 19, 1998. The inspectors observed manual testing of the rod in the core and subsequent disassembly of the removed control rod drive mechanism.

b. Observations and Findings

The licensee developed a special test procedure to manually test the freedom of motion of the subject rod. Before test performance, an evaluation of the procedure was satisfactorily completed and the on-site review committee reviewed the details of the entire evolution. For test conditions, the reactor was in cold condition and depressurized with an adequate shutdown margin available. The licensee performed the freedom of motion test through the intact CRD housing with conditions very similar to a normal rod unlatch conditions. The inspectors verified that the conditions were appropriate for the work. With the inspectors present on January 22, 1998, the licensee used a chainfall to lift the rod from the core approximately 12 inches and then return it to its rest condition. The movement met the acceptance criteria with no rod motion or reactivity problems identified. The licensee readied and removed the CRD for examination.

On January 25, 1998, the inspectors observed the disassembly of the removed mechanism. Vendor representatives were in air fed hoods, communication headsets, and full body plastic suits for the work. The inspectors could view the work through windows in the special sealed plastic tent constructed for the work.

The disassembly and inspection process did not identify a definitive cause for the failure to latch. Corrosion product buildup was found inside the mechanism, but the vendor described this as normal when compared with other disassembled mechanisms. A thrust bearing locking nut was three turns loosened. The locking cup for the nut had not been sufficiently deformed to lock the nut completely. The licensee indicated that this by itself was not the problem. The roller bearings that drive the rod could still be pulled into the lead screw. The rotor assembly parts that electrically pulled out to allow engagement of the rollers showed grooves on their outside diameter. Grooves were in the corrosion product coating. The vendor indicated that this indicated that the parts were probably reaching their maximum outward movement.

The licensee and vendor removed the subject mechanism to the vendor's contaminated test facility for further dynamic testing. The overall inspection work was performed in a satisfactory manner and with care to detect as-found conditions.

c. Conclusions

The licensee and its primary vendor removed and disassembled a malfunctioning Unit 1 control rod mechanism, finding no definitive problem. The overall inspection work was performed in a satisfactory manner, with care to detect as-found conditions.

M1.3 Pressurizer Drain Line Removal and Installation

a. Inspection Scope (71707, 62707, 37551)

As indicated in Section O1.7, the drain line from the pressurizer surge line developed a leak on January 26, 1998. After plant depressurization and drain to approximately 60 inches on LT-5, the line was removed and replaced. The inspectors observed the line removal, replacement, and re-welding.

b. Observations and Findings

After meeting appropriate plant conditions for the work, operations released WO 98009597-05, to remove the one-inch diameter line. The line consisted of the pressurizer surge line to drain line nozzle joint, a short vertical run, four elbows and three short pieces of pipe arranged in "C" configuration, and then a straight, vertical twenty-foot run of pipe to the equipment drain header near the basement level. The piping was per plan with five "U" bolt hangers on the twenty-foot run. The inspectors verified the plant was in stable condition for work performance and appropriate clearances had been set. At the first pipe cut at the surge line drain line nozzle, no water was observed (only dripping). The pipe end moved 1.75 inches down and 1.25 inches toward the reactor vessel when cut. The motion was in a plane created by the four elbows in the expansion segment of the drain line. This freed motion indicated that the piping was under some residual stress that had placed a preload on the piping. Analysis of the piping arrangement is discussed in Section E1.1. The supporting health physics and

maintenance personnel worked well together, taking adequate precautions to make the work progress smoothly, maintaining adequate radiological controls, and practicing good foreign material control.

The inspectors observed portions of the prefabrication of the replacement piping in the machine shop and the class one welds made in the RB. The work went well with good foreign material practices being observed. Upon radiographic inspection of the prefabrication work, two of seven butt weld joints were found to have inadequate fusion; and therefore requiring rework. This use of prefabrication was an acceptable methodology and practice. The RB work was well controlled with proper use of purge gases. Weld interpass temperatures were appropriately monitored. The licensee stated that the radiographs were acceptable on all completed and Duke Quality Assurance accepted welds.

While welding one of the joints, purge paper was used to plug the surge line connection and keep condensate from the weld area. An excessive amount of this dissolvable paper was used and it did not dissolve after the welds were completed, requiring further repairs. This is further discussed in Inspection Report 50-269,270,287/98-01.

c. Conclusions

During the pressurizer surge line drain line work, pipe removal and reinstallation practices and controls were generally acceptable. Health physics personnel appropriately supported the maintenance activities. One rework item was observed that is discussed as a violation in Inspection Report 50-269,270,287/98-01.

M1.4 Unit 1A Once Through Steam Generator (OTSG) Primary-to-Secondary Leakage

a. Inspection Scope (50002)

The inspectors reviewed the circumstances of, and the corrective action for, the primary-to-secondary OTSG leakage that led to the December 28, 1997, shutdown of Unit 1.

b. Observations and Findings

On December 28, 1997, during start-up from a refueling outage, Oconee Unit 1 was required to shut down due to primary-to-secondary leakage. Plant chemistry personnel measured the leakage to be greater than 400 gpd from the 1A OTSG. When the 1A OTSG was opened for inspection, leak testing showed that the primary source of leakage was at the interface between the upper (hot leg) tubesheet and the OTSG tubes. Minor leakage was also found at a remote welded plug location on the lower (cold leg) tubesheet.

The configuration of the connections between the OTSG tubes and the upper tubesheet is unique in the Oconee 1A OTSG. This uniqueness is the result of field repairs to the upper tubesheet after foreign material during hot functional testing damaged it in 1972. In the standard connection between OTSG tubes and the upper tubesheet of a Babcock and

Wilcox (B&W) OTSG, the tubes protruded approximately ⅜ to ½ inches beyond the top of the tubesheet; the tubes were partially rolled in the tubesheet to provide the mechanical connection; and fillet welds connected the outside of the tubes with the tubesheet to provide the seals. The untubed lane of tubesheet holes was plugged with button plugs that were fillet welded into place. In the Oconee 1A OTSG, the tubesheet and tube connections were repaired by machining the damaged tube ends flush with the top of the tubesheet; re-rolling the top of the tube in the tubesheet; and seal welding over the seam between the tube and the tubesheet to repair the hot functional damage. Encapsulating the plugs with a weld overlay repaired the row of button plugs in the untubed lane.

After the December 28, 1997, shutdown, initial test results in the 1A OTSG indicated that there were eleven leak locations and three different types of leaks. After the first repair attempts, subsequent test results identified eight leaking locations; seven of these locations had not been previously identified, and one of these provided a fourth type of leak.

Leakage from Button Plug Locations Adjacent to Tube Location 77-7

A section of the weld overlay encapsulating the button plug row, adjacent to tube location 77-7, had been machined away; this machined area appeared to be the major source of leakage. Tube location 77-7 had been plugged during the Spring 1994 refueling outage, and it was during this evolution that the section of weld overlay was machined away. B&W nonconformance reports 94-00271 and 94-00271-01 reported a sequence of events in which attempts to install a remote welded plug at location 77-7 were unsuccessful, due to interference from the adjacent weld overlay. At the time that a portion of the weld overlay was removed, the new configuration was left as-modified, with the understanding that the machining should not have encroached on the original button plug weld.

The leaking area of the weld overlay was manually repair welded and successfully leak-tested. A full examination of the weld overlay area showed that the area adjacent to location 77-7 was the only location where metal had been removed to install an adjacent plug.

Remote Welded Plug (RWP) leaks

The RWP at location 87-61 in the lower tubesheet of OTSG 1A and the RWP at location 97-92 in the upper tubesheet of OTSG 1B had been installed during the past refueling outage (RFO 1EOC-17) as a result of tubes being pulled for inspection. (RWPs in OTSG B were examined after a review of records showed that 7 of 28 RWPs installed in OTSG B during the past outage had experienced rejects during welding.) Both of these RWPs had experienced two rejects prior to final weld acceptance.

The two leaking RWPs were manually weld-repaired and successfully leak tested. The licensee's review of RWP records from the last outage showed that 2 of 23 RWPs in OTSG A, and 7 of 28 RWPs in OTSG B had experienced weld rejects during installation. This reject rate of 25

percent in OTSG B, and 17 percent overall appears to be rather high for a remote welding process.

The licensee's corrective actions for this problem included leak testing of future RWPs and requiring the contractor to review the welding process to determine if enhancements could be made to reduce the reject rate.

Tube Seal Weld Leaks

Nine locations on the OTSG 1A upper tubesheet were found to be leaking during bubble testing after shutdown; these locations were 40-1, 145-1, 144-1, 140-1, 139-1, 137-2, 136-6, 75-126, and 12-71. After re-rolling these tubes in the tubesheet, (using a recently qualified re-rolling technique) one of the original locations, 136-6, and eight additional locations, (116-2, 148-41, 147-46, 144-2, 146-51, 81-124, 116-1, and 144-56) were found to be leaking. All of the seal-weld, leak locations were at, or near, the periphery of the tubesheet.

The apparent root cause of the seal weld leakage was postulated to be a stress corrosion cracking (SCC) phenomena brought on by the machining of the tubesheet surface during the repairs in 1972. A licensee requested review of the accident analyses for the Oconee OTSGs showed that during a main steam line break (MSLB), flexure of the tubesheet is postulated to cause dilation of the peripheral holes near the surface of the tubesheet, thereby transferring the axial MSLB loads from the rolled joint to the seal welds, which have been shown to be susceptible to SCC. (The MSLB analyses for the Oconee units predicted much higher axial loads on the upper tubesheet than did the MSLB analyses for other B&W once through steam generators. The absence of main steam isolation valves in the Oconee design apparently contributed to these higher loads.)

The licensee had recently qualified a re-rolling process (due to indications in the upper tubesheet roll transition area) which places a new rolled joint about three inches below the top of the tubesheet. The MSLB accident analysis showed that the new location would not be significantly affected by the postulated MSLB hole dilation.

To correct this potential problem, the licensee re-rolled greater than 1700 peripheral tubes in the upper tubesheet of OTSG 1A. The final acceptance of the re-rolled tubes included eddy current testing and leak testing. After the completion of testing, forty tubes were removed from service by plugging: two tubes, (75-126, and 144-1) were due to seal weld leakage after re-roll; six tubes, (3-32, 3-34, 44-1, 84-131, 136-6, and 150-6) were due to unacceptable eddy current indications at or below the re-rolled area; and thirty-two tubes, (1-12, 5-3, 5-44, 8-56, 20-84, 22-1, 23-7, 25-1, 36-113, 37-1, 42-1, 53-126, 60-129, 65-130, 67-130, 74-125, 83-132, 85-130, 87-130, 88-129, 102-123, 130-93, 137-1, 138-75, 139-73, 143-60, 147-44, 147-46, 148-38, 148-41, 149-32, and 151-10) were because the configuration of the re-rolled area did not meet acceptance standards.

Manual Welded Plug Leak

After completion of the repairs to the weld overlay area adjacent to location 77-7, subsequent leak testing showed a pinhole leak in the manual weld of location 75-8. This tube location was extremely close to the leaks in the weld overlay, and therefore this leakage was masked during the initial leak testing of the OTSG.

The weld pinhole, at location 75-8, was manually weld-repaired and successfully leak tested. The licensee is considering the addition of leak testing to the acceptance criteria for future manual welds.

The inspectors reviewed the licensee's root cause process and report, and observed OTSG inspection and recovery activities. Activities observed included visual inspections, leak-testing, re-rolling, and eddy current inspections. Based on the reviews of video tapes of the tube sheet inspections, reviews of 1974 and 1977 documentation, and observation of recovery activities, the inspectors agreed with the root cause(s) and corrective action conclusions reached by the licensee's investigation team. In particular, the inspectors agreed with the conclusions that pointed to an apparent over-reliance on visual inspections for acceptance of welds, and the need for leak testing of future OTSG work. The inspectors concluded that past corrective actions had not adequately considered the role of primary water stress corrosion cracking. (It was not a viable consideration during the tubesheet repairs in 1972, and the weld overlay modification in 1994.)

The long term corrective actions recommended by the licensee's investigation team charged the licensee's OTSG Maintenance Group with ensuring that the contractor's welding and inspection procedures and acceptance criteria were modified to preclude recurrence. The inspectors agreed that the licensee's responsible organization, the OTSG Maintenance Group, should adopt a more questioning attitude toward the contractor's procedures and criteria.

c. Conclusions

The December 28, 1997, Unit 1 shutdown for primary-to-secondary leakage was the result of past repairs, where there had been an apparent over-reliance on the results of visual inspections, and less than adequate appreciation for primary water stress corrosion cracking.

M3 Maintenance Procedures and Documentation

M3.1 Unexpected Effect of Letdown Flow Calibration on Unit 3 Thermal Power Best

a. Inspection Scope (62707)

The inspectors reviewed the maintenance aspects of an unexpected power increase on Unit 3. The details of what happened and the operational aspects of the power increase have been included in Section O1.4.

b. Observations and Findings

On January 15, 1998, maintenance personnel were calibrating letdown flow instrumentation in accordance with Procedure IP/0/B/0202/01h, High Pressure Injection System Letdown Flow Instrument Calibration, Revision 16, when core thermal power began to increase. The licensee investigated and determined the cause of the power increase was the effect that changing letdown flow signal had on the ICS. The licensee determined that letdown flow was an input into the secondary thermal power calculation performed by the operator aid computer (OAC). This thermal power calculation was used by the ICS as a feedback signal for core thermal power.

The licensee suspended the calibration, placed Procedure IP/0/B/0202/01h on administrative hold, and initiated PIP report 3-098-0232. The licensee began a review of procedures affected by the OAC core thermal power calculation and subsequently determined that Procedure IP/0/B/0202/01h had not been identified as affecting the core thermal power calculation or the ICS when ICS was returned to service after modification on March 27, 1998.

The inspectors reviewed applicable site documents to understand the modification interaction process. Documents reviewed were as follows: Procedure IP/0/B/0202/01h; Problem Report 3-098-0232; Modification ON-32989, 3EOC16-ICS Replacement, Revision 0; and Nuclear Station Directive (NSD) 301, Nuclear Station Modifications (NSM), Revision 13. Additionally, the inspectors interviewed licensee personnel on how procedures affected by plant modifications are identified and changed.

NSD 301, Section 301.3.1.11, stated that the superintendent of maintenance was responsible for identifying and developing any instrumentation procedure revisions required as a result of modification work. NSD 301, Sections 301.5.4.4 and 301.6.3.7, stated that prior to acceptance of a modification by operations, all procedure revisions would be completed. With the modification of the ICS, neither procedure IP/0/B/0202/01h nor modification ON-32989 addressed or made any mention of an impact on ICS by letdown flow calibration. The inspectors also identified that the maintenance department lacked a section level procedure governing the process for identification and revision of procedures affected by modifications.

TS 6.4.1.e requires the station to be maintained in accordance with approved procedures for maintenance of equipment which could affect nuclear safety. The failure to revise Procedure IP/0/B/0202/01h to include effects of modifications to the ICS is a violation (VIO) of this TS and is identified as VIO 50-269,270,287/97-18-05: Failure to Revise Procedure Following ICS Modification.

c. Conclusions

The inspectors identified a violation for failure to revise a high pressure injection system letdown flow instrument calibration procedure following modification of the Unit 3 ICS.

M3.2 Oconee 600 Volt K-line Breakers

a. Inspection Scope (62707)

On February 2, 1998, the SSF was removed from service for maintenance. Included in the maintenance was testing and inspection of six Asea Brown Boveri (ABB) K-line 600 Volt load center OXSF breakers. During the testing, problems were discovered. The inspectors observed portions of the repair and retesting.

b. Observations and Findings

During the SSF maintenance, the licensee discovered some breaker lubrication and breaker trip time delay problems. These problems were promptly brought forward for management attention and problem reports 4-98-515 and 516 were initiated. One breaker had sufficient hardening of its grease such that it may not have reclosed completely if it had tripped. These breakers have no automatic re-latching capability. The remaining five breakers had operated satisfactorily during as-found testing, but upon inspection, they did exhibit signs of grease hardening that required work. All six breakers were satisfactorily disassembled, greased, and retested. In addition, the over-current trip devices (identified as SS4G) for three of the breakers were found out-of-tolerance (under time by 2 to 8 seconds) for the long time delay minimum acceptance criteria. These devices were replaced with new ones. The licensee was evaluating the impact of the out-of-tolerance condition on past operability and determining root cause of the problem. Inspector review of breaker coordination revealed that there appeared to be no safety-problem.

There are approximately thirty-seven other safety-related K-line breakers on-site. There are eleven per unit with four common to all units. These breakers are normally closed and contain no under voltage trip circuits. They are supplied from three redundant power trains, each of which are supplied independently from one of the three 4160 volt switchgear, as described in the UFSAR. The breakers only function would be to trip if a safety device were to fail. If one of the 600 volt breakers failed to trip, its 4160 volt supply breaker would open. The failure of one train of 600 volt safety power is an evaluated condition during a design basis event.

The licensee was to evaluate the following:

- grease hardening impact on a preventive maintenance schedule
- trip device impact on SSF K-line breaker preventive maintenance and
- past operability evaluation on SSF trip device supplied breakers

Pending resolution of this issue, this is identified as Inspector Followup Item (IFI) 50-269,270,287/97-18-06: K-line Breaker Issues.

c. Conclusion

During the inspection and testing of the SSF 600 volt breakers, several problems were identified by the licensee. The licensee satisfactorily addressed the immediate equipment problems. There were several issues regarding grease hardening and trip device past operability. An IFI was initiated on those issues.

III. Engineering

E1 Conduct of Engineering

E1.1 Steam Leak in Unit 1 Pressurizer Surge Line (PSL) Drain Line

a. Inspection Scope (55050)

The inspectors determined by observation of completed welds and document review, the adequacy of replacing the drain line on the PSL. The governing code was the American Society of Mechanical Engineers (ASME), Section XI, 1989 Edition with no Addenda, and the American National Standards Institute (ANSI) B31.7, 1968 Edition. The drain line was identified as Duke Class A piping. The leak occurred near the PSL and could not be isolated. The replacement was performed under Work Order 98009597-5.

b. Observation and Findings

On February 2, 1998, the inspector visited Oconee Unit 1 to inspect repairs to the PSL drain line steam leak attributed to a crack near a 90 degree elbow weld on the expansion loop of the drain line. The leak was discovered on January 27, 1998. Through discussion with technical personnel and document review, the inspectors learned that on the morning of January 27, 1998, Oconee Unit 1 was heating up and pressurizing the RCS to the hot shutdown condition. During this time, operation personnel identified a leak in the RCS, which they subsequently verified as a steam leak in the PSL drain line. The leak was found at an elbow weld on the expansion loop of the drain line. The drain line was bounded by the PSL and valve 1RC-18 near the equipment drain line header, at the basement floor level. It was determined that the leak rate was 1.7 gallons per minute. Following plant cooldown and cold shutdown, the licensee removed the failed section of the line with a cut at the outlet of the PSL drain line nozzle and another just below the expansion loop. The welds on the drain line section were liquid penetrant inspected. There were no additional cracks found. Selected samples of straight piping and elbows were sent to the Lynchburg Technology Center for a metallurgical investigation. A review of the metallurgical investigation report disclosed that the failure resulted from stress corrosion cracking, which originated on the intrados of the third 90-degree elbow from the PSL drain line nozzle. The aggressive material associated with this type of failure mechanism was chlorides. The licensee believes that these chlorides came from combustion of material containing polyvinyl chlorides during a 1973 fire in the reactor building 1A cavity. PIP report 1-098-0357 was issued to

document this event and the metallurgical investigation that was performed to determine the apparent root cause of the failure.

Replacement Piping, Installation and Testing

At the time of this inspection on February 2, 1998, the replacement drain line had been installed. The inspector inspected the new welds, reviewed the weld packages and the associated radiographs, all of which were found to be satisfactory.

During plant heat up, the licensee determined that there was no flow in the drain line. An investigation determined that a plug, which was made from purge paper and used to prevent water from dripping on the drain line welds during fabrication, was lodged in the pipe and would not dissolve as expected. For more details on this matter see Inspection Report 50-269,270,287/98-01. Following an evaluation of the potential impact that the paper material could have on the RCS, the licensee decided to cut the line, remove the plug by mechanical means, re-weld the line and fill up the system for testing. By review of the above mentioned PIP report, the inspector ascertained that the failure investigation process team had identified an engineering or design error in the stress analysis calculation (OSC 4349) of the drain line system. A description of the error was documented in PIP report 1-098-465.

Error in Stress Analysis Calculations

A review of PIP report 1-098-465 disclosed that from the time Unit 1 commenced operation, until approximately September 19, 1981, support S/R59-0-478A-H9 was on the drain line near the PSL drain line nozzle. The support was removed per NRC Bulletin 79-14 reanalysis request. Monitoring of the PSL movement in response to IEB 88-11, disclosed that the PSL was susceptible to thermal stratification that resulted in greater movement than originally addressed. In 1991, the licensee reanalyzed the PSL. However, the present review revealed that the re-analysis addressed only stresses from the configuration without support S/R 59-0-478A-H9. The licensee's subsequent analysis of stress conditions prior to the removal of S/R59-0-478A-H9 indicated that certain locations on the drain line and the drain line nozzle were significantly over stressed. This over stressed condition was identified as an indicator of cycling the stress range beyond twice the yield point, which appears to have been mostly responsible for the initiation of the crack. However, in reference to the drain line, the licensee determined that the stress overload condition had been rectified by the removal of S/R 59-0-478A-H9 and the removal of the original drain line. The drain line was replaced from the drain nozzle down to a location on the vertical run below the expansion loop.

Qualification of Drain Line Nozzle for Continued Operation

In addition to this analysis, the licensee performed a calculation to evaluate the flaw tolerance of the PSL drain line nozzle. A review of the results disclosed that the subject nozzle was capable of performing its required function for all design loading for one fuel cycle. During

this time frame the licensee will re-evaluate the problem and determine the appropriate corrective action to be taken to bring the drain nozzle into compliance with the applicable code requirements. On February 2, 1998, the licensee discussed this matter with the staff at Nuclear Reactor Regulation (NRR), who agreed with the licensee's methodology. No operability issues on this matter were identified during this call. The licensee plans to continue power operation for one fuel cycle, which provides sufficient time to decide the appropriate actions that will be taken to return the PSL drain line nozzle into compliance with applicable code and UFSAR requirements. This matter was identified as an inspector followup item to allow for a review and verification that the subject nozzle had been returned to compliance with code requirements and FSAR commitments, IFI 50-269/97-18-07: Pressurizer Surge Line Drain Line Nozzle Loads Exceed Stress Analysis Limits.

c. Conclusion:

Replacement of the cracked one-inch drain line on the pressurizer surge line was consistent with applicable code requirements. A lack of attention to details in the planning phase of welding the replacement line caused a significant job delay and the need to cut and re-weld a new weld on the line. Engineering provided adequate support and took an active role in determining the root cause of the crack. Welding, nondestructive examination, and process control activities were satisfactory. Stress analysis calculations determined that thermal stratification and hanger loads on the drain line, exceeded code allowable usage factor requirements, on the drain line nozzle.

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 2 Integrated Control System Neutron Error Spikes

a. Inspection Scope (62707, 92903)

The inspectors observed, between January 6 and 7, 1998, troubleshooting activities, engineering support, operator actions, and prejob briefings relating to the Unit 2 ICS neutron error spikes.

b. Observations and Findings

The ICS neutron error spikes were occurring randomly and were causing unwarranted control rod movements. The problem was captured in PIP 2-97-4615. Engineering had begun power monitoring of the ICS and had narrowed down the problem to several components. Prior to the troubleshooting activities the average temperature module started a decreasing trend. This resulted in minor rod movements.

Among the specific items observed by the inspector were: the replacement of two relays associated with the average temperature; tracing of the power lead which was to be lifted inside ICS cabinet number 6 for various modules associated with the neutron error signal; the replacement of a potentially degraded connector plug for a module in the ICS; and the prejob briefings for the replacement of the relays and the

connector plug. The inspector had not observed the hand-over-hand tracing of the neutral line that was to be lifted for the repair work. Engineering and instrumentation personnel had written a troubleshooting procedure for the work.

On January 7, 1998, the inspectors observed that during the prejob briefing for the replacement of the connector plug, the engineer informed the operators that the activity would have minimal impact on the unit. The lifting of the black power lead on the connector plug per the troubleshooting procedure, would result in the loss of startup feed water flow indications that were not needed at full power. When maintenance personnel lifted the white neutral wire, several events, both expected and unexpected occurred. Expected changes such as the 2A and 2B startup feedwater flow indication being lost occurred. The following items that were unexpected also occurred: the 2A and 2B main feedwater flow indication was lost; the smart analog signal select (SASS) system detected a loss of main feedwater indications on the A and B loops and selected a good indication; and the 2A and 2B main feedwater pump controllers shifted from the automatic mode to the manual mode of operation. In this condition, the unit controls would not have responded to a feedwater pump automatic runback. Correct SASS system operation prevented a plant trip. The encountered problems were documented in PIP report 2-98-44.

The shift operations manager directed the engineer and the technicians to stop work, to review the activity, and to determine the extent of the loss of ICS modules and relays. The review indicated that the white neutral wire was attached to modules and relays in ICS cabinets other than those originally identified. The procedure manipulation affected these other components. Subsequently, the licensee personnel involved found all other neutral wire connected components. The other components not previously identified were visually difficult to see. After satisfying operations of the completeness of their more recent tracing and completion of procedure changes, the repair work was completed successfully.

During the initial work on January 7, 1998, maintenance had not adequately traced the white neutral lead. This error had been introduced into the licensee's troubleshooting procedure. 10 CFR 50, Appendix B, Criteria V, Instructions, Procedures, and Drawings, conformed to by the licensee's quality assurance program, requires that activities affecting quality shall be prescribed by documented instructions, procedures, and drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. NSD 703, Administrative Instructions for Station Procedures, Revision 17, Section 703.5, Preparation of Procedures, states, in part, that procedures shall be written to minimize risk to equipment and should, when appropriate, instruct persons performing the procedure what responses to expect from their actions. Further, as required by the NSD, the licensee had not validated the procedure to ensure usability and operational correctness. The troubleshooting procedure written for the repair (WO 98000451) failed to meet these requirements. This failure is identified as an

example of VIO 50-269,270,287/97-18-08: Failure to Establish and Implement Procedures - Three Examples.

c. Conclusions

The inspectors identified the first of three examples of a violation involving procedural inadequacies. (The other two examples are discussed in Section E2.2.) An engineering supported troubleshooting procedure did not minimize risk to equipment and was not completely validated prior to performing work. Use of the procedure on Unit 2 ICS wiring resulted in unexpected system responses.

E2.2 Keowee Testing, Failure to Start, and In-Service Testing

a. Inspection Scope (37551, 92903)

The inspectors observed and reviewed engineering support for testing involving the Keowee Hydroelectric Plant (KHP). The inspectors responded to the KHP for observations and reviews of engineering support when: on January 9, 1998, the Unit 2 generator failed to start in the normal mode; on January 14, 1998, voltage adjust did not run to preset as expected during testing; and, on January 20, 1998, both of the KHP units were out of service due to a missed in-service test.

b. Observations and Findings

On January 9, 1998, the KHP operations personnel started the KHP Unit 1 generator, which successfully paralleled automatically to the grid as expected. When the Unit 2 KHP generator was started, it came up to rated speed, received a UNIT 2 INCOMPLETE START alarm, and tripped. The KHP units were being started to control Keowee Lake level.

The inspectors observed and reviewed activities involved with engineering support, troubleshooting, information gathering for root cause, prejob briefings for the various work activities, and the adjustment of the motor operated automatic voltage regulator. The troubleshooting identified an open coil in a time delay relay (Agastat 90X1A/TD) that prevented the regulator from shifting to automatic control. With the regulator not shifting to automatic, the unit received the incomplete start alarm and tripped. The licensee replaced the relay, tested the unit, and returned it to operable status.

The inspectors observed, during the troubleshooting, that the regulator was not adjusted in accordance with drawing KEE-212-5, Elementary Diagram Excitation System Motor Operated Auto Voltage Adjuster, Revision 8, a Quality Assurance (QA) Condition 1 drawing. The inspectors found that Procedure IP/0/A/2005/003, Keowee Hydro Station Westinghouse WTA Voltage Regulator Test, Revision 23, did not contain adequate detail to properly set up the voltage adjuster. The procedure did not address the unused timing cams in the adjuster that, if unaccounted for, could cause operational problems. (The unaccounted for cams had not caused operational problems at discovery.) Following the Unit 2 adjustment, the Unit 1 regulator was checked and was also not in accordance with the

applicable drawing. Subsequently, the licensee properly adjusted both cams. During the work, the operational status of the Keowee units was properly addressed. These voltage adjusters had been previously worked by the above procedure.

10 CFR 50 Appendix B, Criteria V, Instructions, Procedures, and Drawings, conformed to by the licensee's QA program, requires that activities affecting quality shall be prescribed by documented instructions, procedures, and drawings of type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. The failure to have a detailed, adequate procedure for adjusting the motor operated regulator in accordance with drawing KEE-212-5, Revision 8, is a violation of these requirements. NSD 703, Administrative Instructions for Station Procedures, Revision 17, Section 703.5, Preparation of Procedures, Subsection 4, subsection requirements stated, in part, that procedures shall be written in adequate detail to ensure accurate results. This item is identified as an example of VIO 50-269,270,287/97-18-08: Failure to Establish and Implement Procedures - Three Examples. The licensee initiated a failure investigation team and problem report K-98-106.

On January 14, 1998, during the performance of test PT/0/A/0610/22, Degraded Grid, Switchyard Isolation, and Keowee Over Frequency Protection, Revision 8, the KHP Unit 2 did not return to the preset automatic generator voltage level as required. With support from engineering, a defective Cutler-Hammer Type D87 timer relay was discovered. The timer failed to allow enough time for the motor operated automatic voltage adjuster to run the voltage back to the preset level. The licensee replaced the timer relay and the test was successfully completed. The inspectors found that type D87 timer relays had failed on a previous occasion. The licensee initiated a second failure investigation and PIP report K-98-211. The licensee has sent both of the failed relays to vendors for evaluation. Pending additional inspector review of the licensee's efforts in this area, this is identified as IFI 50-269,270,287/97-18-09: Review of the Root Cause Analysis for Agastat Time Delay and Type D87 Timer Relays.

On January 20, 1998, during a quarterly surveillance and maintenance outage for KHP Unit 2, it was discovered that an in-service test (IST) had not been performed when required on both KHP units. Both units were declared inoperable and the appropriate TS and selected licensee commitment was entered. The inspectors found that a temporary IST Procedure TT/0/A/0620/16, KHU-1 Turbine Guide Bearing Oil System Test, Revision 1, was not converted to a performance test (PT). This resulted in an IST of check valves in the oil system for Keowee Unit 1 not being performed within the required time frame. The required ISTs were

performed using the temporary procedure and both KHP units were declared operable.

NSD 300, ASME Section XI Program, Revision 2, states, in part, that the nuclear site engineering organization is responsible for interfacing with the station organization to prepare written test procedures. Not

converting the temporary procedure to a PT is a violation of this requirement. This item is identified as an example of VIO 50-269,270,287/97-18-08: Failure to Establish and Implement Procedures - Three Examples.

At the end of the report period, licensee personnel had completed a review of temporary procedures for conversion to permanent procedures with no discrepancies identified. The licensee was also conducting root cause determinations for the open coil on the time delay relay and the failed timer.

c. Conclusions

Two additional examples of a three-example violation involving procedure inadequacies were identified. Section E2.1 discusses the first example of the violation. The two additional examples occurred on the Keowee Hydroelectric units. One example involved the motor operated automatic voltage adjusters on both Keowee units not being adjusted in accordance with their applicable drawings due to a lack of procedural detail. The other example involved missed ISTs on both Keowee Hydroelectric units due to a failure by engineering to convert a temporary test into a periodic test on lube oil valves.

E8 **Miscellaneous Engineering Issues** (92903,92700)

E8.1 (Discussed) LER 50-269/97-10: Inadequate Analysis of Emergency Core Cooling System (ECCS) Sump Inventory Due to Inadequate Design Analysis.

This event was discussed in Inspection Report 50-269,270,287/97-16. The inspectors reviewed the completed evaluation in the LER. During the flow velocity evaluation, the licensee identified that the refueling canal drains contained basket type strainers which could become clogged and trap approximately forty thousand gallons of ECCS and reactor coolant system line break fluid.

The reactor cavity drain had a flange installed with an open 3/4-inch pipe nipple that could also become blocked and trap approximately sixty thousand gallons of fluid. UFSAR section 3.8.3.1, "Description of the Internal Structures," states that the reactor cavity was designed structurally to contain core flooding water up to the level of the reactor nozzles. Framatome Technology Incorporated was contacted by engineering and confirmed that this was an original design issue that was later determined to be unnecessary. The flange on Unit 3 was removed at some unknown time.

The strainers in the fuel transfer canal drains were installed approximately ten years ago during a refueling outage to maintain dose rates during decontamination As Low As Reasonably Achievable (ALARA). Individuals interviewed remembered this to be with verbal concurrence from engineering to remove them prior to operation and reinstall the approved perforated strainer plate. The original strainer plates were never reinstalled.

The system engineering evaluation concluded on January 8, 1998, that the increase in transport velocity did not affect the operability of the reactor building emergency sump. Therefore the sump was determined to be both past and present operable.

Neither the removal of the flange nor the installation of the strainers was evaluated as a modification to the plant through the station modification process. NSD 301, NSM, Revision 12, Section 301.1.1, indicates that it applies to all structures, systems, and components located within the nuclear facility. Section 301.2 further indicates that changes to these structures, systems, and components are considered modifications and require implementation packages. The licensee has subsequently evaluated the removed Unit 3 flange, removed the flanges on the other two units, and, as indicated above, removed the strainers. This non-repetitive, licensee identified and corrected violation is being treated as a NCV consistent with Section VII.B.1 of the NRC Enforcement Policy. This is identified as NCV 50-269,270,287/97-18-10: Failure to Follow Modification Procedures. This LER will remain open pending review of additional issues concerning the Borated Water Storage Tank level and the RB emergency sump level identified at the end of the report period.

E8.2 (Open) Inspector Followup Item 50-269,270,287/96-13-03: Service Water System Modifications and Testing.

The service water system operational performance inspection (SWSOPI) had identified several issues with respect to the design and operation of the low pressure service water system (LPSW) and the emergency condenser circulating water (ECCW) systems. These issues included the cooling and sealing supply to the condenser circulating water (CCW) pumps and motors, maintaining the CCW conduits full of water during siphon operation, the net positive suction head (NPSH) requirements for the LPSW pumps, and the quality condition of certain structures, systems and components (SSC) required to maintain the siphon. The licensee had committed, in a letter dated December 28, 1995, to perform certain modifications to upgrade the ECCW system. These modifications included providing an LPSW supply to the CCW pumps and motors, changes to the LPSW system to ensure adequate NPSH, installing an emergency siphon vacuum system, and upgrading and reclassifying portions of the CCW system to QA-1. The five major modifications have been broken down into approximately eighty implementation parts and minor modifications.

The inspectors reviewed the licensee's progress in implementing these modifications. The following implementation parts have been completed: LPSW minimum flow recirculation piping has been installed on all three units; trenches have been installed from the radioactive waste trench to the intake dike and essential siphon vacuum (ESV) building; the emergency safeguards signal for LPSW 4 and 5 has been removed from Units 1 and 2; new LPSW pump impellers have been installed in Units 1 and 2; Unit 1 CCW pump discharge valve control circuitry has been upgraded; and the new isolation valves for the non-essential turbine building LPSW loads have been installed and related control switches moved to the control rooms.

The inspectors reviewed work in progress, which included completion of the ESV building and installation of the ESV pumps, tanks, valves, power, and instrumentation; installation of the LPSW headers from Unit 1, 2 and 3 in the turbine building; and installation of the LPSW and ESV piping in the trench to the intake dike.

The inspectors discussed the licensee's LPSW implementation plans for the Unit 2 outage, currently planned for March 1998. The implementation parts to be completed during the March outage as currently planned will complete the LPSW modifications on Unit 2. Testing of the ECCW siphon will be conducted on Unit 2 following completion of the modifications. The licensee's current plans are to complete Unit 3 modifications during the fall 1998 outage and the remaining Unit 1 modifications during the spring 1999 outage.

The inspectors concluded that the licensee had made good progress in the installation of the modifications considering the intervening events (feedwater heater line rupture and rework on the balance of plant systems) and the size of the LPSW modifications.

This item will remain open pending the completion of the modifications on all three units and completion of post modification testing.

IV. Plant Support Areas

P8 Miscellaneous EP Issues (92904)

P8.1 Severe Accident Management Guideline (SAMG) Training

Severe accident mitigation guidelines were written to identify options available when plant conditions place the operators outside the current emergency operating procedures. The inspectors reviewed training materials and observed actual SAMG training provided to plant personnel. There were 442 employees that received introductory training on the existence and basis for the SAMGs; 171 of which continued training for the assessment and mitigation strategies. These employees were from shift operations, nuclear engineering, and technical support center personnel. One hundred and seventeen then completed self-paced computer-based training on the science of severe accidents. The licensee also conducted table top drills for 131 of the original 442 employees. The training was completed on December 19, 1997, and the licensee posted a letter to the NRC describing the training. The inspectors attended parts of the training, finding the training and guidelines to be of sufficient detail for the intended purpose.

P8.2 Meeting With Local Emergency Preparedness Officials

The resident inspectors met with local officials following the completion of the Systematic Assessment of Licensee Performance (SALP) meeting on January 8, 1998. The purpose of the meeting was to introduce the new inspectors to the officials and to allow discussion of any concerns the officials may have. No concerns were identified by local officials.

F1 Control of Fire Protection Activities

F1.1 Transformer Fire Watches

a. Inspection Scope (71750)

On January 17, 1998, the licensee determined that they had not established appropriate fire watches during the out-of-service periods for two transformers. The inspectors followed the licensee's activities and corrective actions.

b. Observations and Findings

On January 17, 1998, at approximately 2:00 p.m., the operations staff determined that they had not implemented fire watches in accordance with a site instruction. Operations generated problem report 98-0255 and notified the inspectors. Operations personnel had taken the deluge fire protection and detection systems out-of-service for the startup transformers on Units 2 and 3. They had accomplished the preventive maintenance on CT2 and CT3 on January 15, 1998. Operations was preparing to take the systems out on Unit 1 when it was discovered that Selected Licensee Commitment 16.9 and NSD 316, Fire Protection (dated December 30, 1997), had been misapplied. Specifically, hourly fire watches had been established instead of the continuous fire watches as required by both instructions. Operations personnel had mistakenly thought that they had not taken the detection system out-of-service when the fire water header was isolated on each of the two transformers. The decision point regarding hourly or continuous fire watches was in the procedure, but it did not specify what took the detection system out-of-service. Making the correct decision required an understanding of the transformer fire suppression system. The licensee placed appropriate watches on Unit 1. NSD 316 was scheduled to be enhanced to point out that the detection system was disabled with the isolation of the transformers' fire header. This non-repetitive, licensee identified and corrected violation is being treated as an NCV consistent with Section VII.B.1 of the NRC Enforcement Policy. This is identified as NCV 50-270,287/97-18-11: Failure to Implement Continuous Fire Watches During Transformer Deluge System Maintenance.

c. Conclusions

An NCV was identified for failure to perform a continuous fire watch as required by the fire protection program and selected licensee commitments. The licensee had performed hourly fire watches instead of continuous fire watches when the fire protection deluge system was taken out of service for the startup transformers on Units 2 and 3.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 11, 1998. The licensee acknowledged the findings presented. No proprietary information was identified to the inspectors.

X2 Notice of Enforcement Discretion for Units 2 and 3

a. Inspection Scope (92903)

The licensee has had many regular outage schedule disruptions, due to many forced outages on all three plants in the last several years. The realization of associated surveillance schedule problems led the licensee to have discussions with the NRC and produce several TS submittals. The inspectors followed the activities and read the TS submittals for correctness.

b. Observations and Findings

On January 15, 1998, the licensee submitted a TS change request in accordance with 10 CFR 50.90. The requested amendment titled, Request for Technical Specification Amendment for Test and Calibration, consisted of a proposed one-time extension to the instrument channel test frequency for several instruments and engineering safeguards channel surveillances. The NRC was processing that change in accordance with the normal thirty-day comment period. Several days later, the licensee discovered more TS driven surveillances that had not been included in the January 15 submittal. The licensee engaged the NRC in discussion about including these additional items in the January 15 submittal. Due to NRC process requirements, NRR could not include those additional surveillances in a timely manner to support Unit 2 surveillance due dates. The end of initial TS surveillance grace limit for the potentially overdue low pressure injection cooler performance test surveillance was February 14, 1998, while the unit refueling was scheduled for March 13, 1998. The licensee then questioned the NRC whether they could perform the surveillances scheduled to be completed at refueling outages, at other times. The response from NRR in NRC headquarters was that surveillances specified for refuelings per TS must be completed during refueling outages. On January 30, 1998, the licensee submitted a request for a Notice of Enforcement Discretion (NOED) for Refueling Outage Frequency Surveillances. NRR had verbally granted the discretionary enforcement to the licensee on January 30, 1998. After the granting of discretionary enforcement, the licensee submitted a February 2, 1998, TS change altering the surveillance frequency dates. The change which affected 93 surveillances, aligned the Oconee TS with the NRC approved standard TS. That left several surveillances to be performed later in February 1998 while Unit 2 was at power operation, which was after the end of this inspection period.

The inspectors reviewed the proposed new TS for content. The licensee appeared to have identified all the locations in the TS were refueling, refueling outage, or "RF" (abbreviation for refueling frequency) had been used. The licensee was submitting a page change to the last submittal correcting a paragraph 4.2.2 change back to refueling outage frequency from eighteen months. These involved inspections of the core barrel to core support shield caps that should be inspected each outage. This change was due to be issued on or about February 19, 1998.

Several items are planned or have occurred in response to the above administrative events. The NRC performed a review of the surveillance process, which is discussed in Inspection Report 50-269,270,287/98-01. NRR has issued or planned to issue the required documentation on the licensee's submittals. The licensee was to issue an LER on the required surveillance issue. Pending further review, this will be identified as URI 50-269,270,287/97-18-12: Refueling Outage Surveillance NOED.

c. Conclusions

On January 30, 1998, the licensee was granted verbal enforcement discretion on statements of their TS regarding surveillance performance intervals. The licensee submitted a TS change to allow eighteen-month periodicity of surveillance instead of a refueling outage periodicity. The inspectors had reviewed the change for completeness. Additional followup on the enforcement discretion will be tracked under an unresolved item.

X3 NRC Management Meetings

On December 16, 1997, Mr. Hugh Thompson, Jr., Deputy Executive Director for Regulatory Programs and Mr. Luis Reyes, Regional Administrator, Region II, were at the site to tour the facility and meet with licensee personnel.

Partial List of Persons Contacted

Licensee

E. Burchfield, Regulatory Compliance Manager
T. Coutu, Scheduling Manager
D. Coyle, Mechanical Systems Engineering Manager
T. Curtis, Operations Superintendent
B. Dobson, Mechanical/Civil Engineering Manager
W. Foster, Safety Assurance Manager
D. Hubbard, Maintenance Superintendent
C. Little, Electrical Systems/Equipment Engineering Manager
W. McCollum, Vice President, Oconee Site
M. Nazar, Manager of Engineering
B. Peele, Station Manager
J. Smith, Regulatory Compliance
J. Twiggs, Manager, Radiation Protection

Other licensee employees contacted during the inspection included technicians, maintenance personnel, and administrative personnel.

NRC

D. LaBarge, Project Manager

Inspection Procedures Used

IP37551	Onsite Engineering
IP50002	Steam Generators
IP55050	ASME Welding
IP61726	Surveillance Observations
IP62707	Maintenance Observations
IP71707	Plant Operations
IP71750	Plant Support Activities
IP92700	Onsite Followup of Written Event Reports
IP92903	Followup-Engineering
IP92904	Followup-Plant Support
IP93702	Prompt Onsite Response to Events

Items Opened, Closed, and Discussed

Opened

50-269/97-18-01	NCV	Inadequate RIA Procedure (Section O1.3)
50-269,270,287/97-18-02	URI	Containment Air Lock Testing (Section O1.5)
50-269,270,287/97-18-03	URI	SSF Diesel Generator Operation (Section O3.1)
50-269,270,287/97-18-04	URI	Teflon Tape Use on the LPI System (Section M1.1)
50-269,270,287/97-18-05	VIO	Failure to Revise Procedure Following ICS Modification (Section M3.1)
50-269,270,287/97-18-06	IFI	K-line Breaker Issues (Section M3.2)
50-269/97-18-07	IFI	Pressurizer Surge Line Drain Line Nozzle Loads Exceed Stress Analysis Limits (Section E1.1)
50-269,270,287/97-18-08	VIO	Failure to Establish and Implement Procedures - Three Examples (Sections E2.1 and E2.2)
50-269,270,287/97-18-09	IFI	Review of the Root Cause Analysis for Agastat Time Delay and Type D87 Timer Relays (Section E2.2)
50-269,270,287/97-18-10	NCV	Failure to Follow Modification Procedures (Section E8.1)
50-270,287/97-18-11	NCV	Failure to Implement Continuous Fire Watches During Transformer Deluge System Maintenance (Section F1.1)
50-269,270,287/97-18-12	URI	Refueling Outage Surveillance NOED (Section X2)

Closed

None

Discussed

50-269/97-10	LER	Inadequate Analysis of ECCS Sump Inventory Due to Inadequate Design Analysis (Section E8.1)

50-269,270,287/96-13-03 IFI Service Water System Modifications and Testing (Section E8.2)

List of Acronyms

ABB	Asea Brown Boveri
ALARA	As Low As Reasonably Achievable
ANSI	American National Standard
ASME	American Society of Mechanical Engineers
B&W	Babcox and Wilcox
CFR	Code of Federal Regulations
CCW	Condenser Circulating Water
CRD	Control Rod Drive
ECCS	Emergency Core Cooling System
ECCW	Emergency Condenser Circulating Water
ESV	Essential Siphon Vacuum
F	Fahrenheit
GPD	Gallows per Day
GPM	Gallons Per Minute
ICS	Integrated Control System
IFI	Inspector Followup Item
IST	In Service Testing
KHP	Keowee Hydro (electric) Plant
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MSLB	Main Steam Line Break
mR	Millirem
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NOED	Notice of Enforcement Discretion
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRR	Nuclear Research and Regulation
NSD	Nuclear System Directive
NSM	Nuclear Station Modification
OAC	Operator Aid Computer
ONS	Oconee Nuclear Station
OTSG	Once Through Steam Generator
PDR	Public Document Room
PIP	Problem Investigation Process
PSIG	Pounds Per Square Inch Gauge
PSL	Pressurizer Surge Line
PT	Performance Test
QA	Quality Assurance
RB	Reactor Building
RCS	Reactor Coolant System
REV	Revision
RIA	Radiation Indication and Alarm
RPM	Revolutions Per Minute
RWP	Remote Weld Plug

SAMG	Severe Accident Management Guideline
SASS	Smart Analog Signal Select [system]
SCC	Stress Corrosion Cracking
OTSG	Once Through Steam Generator
SSC	Structure, Systems & Components
SSF	Safe Shutdown Facility
SWSOPI	Service Water System Operational Performance Inspection
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
WO	Work Order