APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/92-07 Licenses: DPR-51
50-368/92-07 NPF-6

Dockets: 50-313
50-368

Licensee: Entergy Operations, Inc. (Entergy)
Route 3, Box 137G
Russellville, Arkansas 72801

Facility Name: Arkansas Nuclear One (ANO), Units 1 and 2

Inspection At: ANO Site, Russellville, Arkansas

Inspection Conducted: March 1-28, 1992

Inspectors: I. Barnes, Chief, Materials & Quality Programs Section
Division of Reactor Safety

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Section A, Division of Reactor Projects

Inspection Summary

Inspection Conducted March 1-28, 1992 (Report 50-313/92-07; 50-368/92-07)

Areas Inspected: This routine resident inspection addressed onsite followup of licensee event reports (LERs), items of regional interest, onsite response to events, monthly maintenance observation, bimonthly surveillance observation, operational safety verification, and refueling activities.

Results:

Strengths

The ANO staff's actions in dealing with the steam generator (SG) tube leak event were commendable. Lessons learned and corrective actions for coping with the defective pressure regulator on the SG sampling system were dispositioned appropriately. Timely and conservative actions contributed to minimizing the extent of the leak and its potential consequences. The licensee's decision to commence a plant shutdown prior to approaching Technical Specification (TS) limits was evidence of prudent measures undertaken to protect public health and safety. (Section 4.2)

Communications between Unit 1 and 2 were excellent during the SG tube leak. In addition, the communications between the Unit 2 operations staff and ANO plant management were excellent. (Section 4.2)

Unit 1 consistently maintained equipment available as described in the Shutdown Operations Protection Plan (SOPP). This plan substantially exceeded TS requirements and provided increased protection during refueling outage conditions. (Section 7.1)

The diversity of reactor coolant pump (RCP) seal cooling methods and well developed abnormal operating procedures (AOPs) and emergency operating procedures (EOPs) were noted as a strength. (Section 3.2.1)

Backlog reduction efforts for Quality Audit Finding Reports (QAFRs) and Industry Event Evaluations were substantially ahead of schedule. (Section 3.2.4)

Early boration of the Unit 1 reactor coolant system was successful at the start of Refueling Outage 1R10. Over 1000 curies of cobalt and cesium were removed from the reactor coolant system (RCS). (Section 7.5)

Unit 2 had a well developed RCS draining procedure which was effectively implemented. (Section 7.2)

Fuel movement for the 1R10 refueling outage was performed by qualified Babcock and Wilcox (B&W) services personnel. The refueling senior reactor operator onshift was knowledgeable of fuel movement safety limits and Procedure 1506.001, Revision 11, "Fuel Handling." (Section 8.1)

Weaknesses:

The licensee's review of Refueling Outage 2R8 eddy current examination (ECT) data for Tube 67-109 revealed the presence of an apparent indication at the failure location above the tube sheet. This indication was not identified for further investigation by either of the two ECT analysts who performed independent reviews of Refueling Outage 2R8 Tube 67-109 data. The failure of both primary and secondary analysts to identify the indications in accordance with procedural requirements was an apparent violation of Criterion V of

Appendix B to 10 CFR Part 50. However, the violation was not cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII of the NRC Enforcement Policy. (Section 3.2.2)

During Refueling Outage 2R8 SG tube ECT, the same individual acted as primary analyst and resolution analyst, thus lacking appropriate independence. In addition, the quality assurance oversight scope was not appropriate for effective identification of contractor performance problems. (Section 3.2.2) The Unit 1 service water system was pressurized for hydrostatic testing with an unauthorized revised test boundary established. This was an apparent violation of TS 6.8.1. (Section 6.1)

Weak as low as reasonably achievable (ALARA) practices were observed during the removal of the Unit 1 RCP D motor housing. (Section 5.3)

DETAILS

1. PERSONS CONTACTED

N. Carns, Vice President, Operations
+*J. Yelverton, Director, Nuclear Operations
+*G. Ashley, Licensing Specialist
T. Baker, Assistant Plant Manager, Central
S. Boncheff, Licensing Specialist
M. Cooper, Licensing Specialist
*S. Cotton, Manager, Radiation Protection/Radiation Waste
*R. Douet, Unit 1 Maintenance Manager
+*W. Eaton, Director, Design Engineering
*R. Edington, Unit 2 Operations Manager
+ C. Eubanks, Supervisor, Engineering Programs
*R. Fenech, Unit 2 Plant Manager
+*J. Fisicaro, Licensing Director
+ D. Harrison, Senior Engineer
+*L. Humphrey, Quality Assurance Director
*A. Jacobs, Supervisor, Surveillance Testing
*R. King, Plant Licensing Supervisor
+ D. Lomax, Manager, Engineering Standards and Programs
+ J. McKenzie, Technical Specialist
D. Mims, Systems Engineering Manager
D. Provencher, Quality Assurance Manager
*R. Sessoms, Central Plant Manager
*J. Vandergrift, Unit 1 Plant Manager
*C. Warren, Unit 2 Maintenance Manager
*T. Weir, Materials and Purchasing Manager
C. Zimmerman, Unit 1 Operations Manager

+Present at exit interview conducted on March 19, 1992, which addressed Unit 2 SG testing.

*Present at final exit interview conducted on March 31, 1992.

The inspectors also contacted other plant personnel, including operators, engineers, technicians, and administrative personnel.

2. PLANT STATUS

2.1 Unit 1

Refueling Outage 1R10 was in progress at the beginning of the inspection period. During the outage, the licensee drained the RCS to reduced inventory and conducted midloop operations to support RCP repair and SG maintenance and inspection activities.

2.2 Unit 2

Unit 2 began the inspection peri at 100 percent power.

On March 9, 1992, at 7 p.m. (CST), the unit commenced a plant shutdown from 100 percent power due to increased SG tube leakage. (Section 4.2) At 8:21 p.m., the unit entered Mode 3 when the operations staff manually tripped the reactor from 20 percent power.

At 3:32 a.m. on March 10, the unit entered Mode 4 and at 7:30 a.m. the unit entered Mode 5. While in Mode 5 the licensee drained the RCS to reduced inventory and conducted midloop operations to perform inspection and repair activities on both SGs. (Section 3.3)

3. ONSITE FOLLOWUP OF LERS AND ITEMS OF REGIO.. INTEREST (92700 and 92701)

3.1 Onsite Followup of LERS (92700)

3.1.1 (Closed) LER 50-368-92-001: "(4) Excore Nuclear Instrumentation Logarimatic Power Level Trip Response Times Not Measured As Required by Technical Specifications Due to Deficient Procedures"

During a review of procedures, the licensee discovered that previous surveillance testing of the excore nuclear instrumentation logarithmic power level high trips was not performed as required by TS.

The inspector reviewed the LER and the completed test package which correctly tested the excore nuclear instrumentation.

The licensee identified this problem as a part of the ANO Business Plan (Item C.1.4) to verify surveillance procedures adequately implement TS requirements. The licensee corrected the method for testing the response time of the detectors to include the required preamplifier portion of the circuit, which was previously omitted. The licensee performed the revised test procedure and the results were satisfactory.

This item is closed.

3.2 Items of Regional Interest (92701)

3.2.1 Units 1 and 2 - RCP Pump Seal Cooling

The inspector reviewed EOPs and AOPs that addressed a loss of RCP seal cooling or potentially degraded RCP seal performance. The inspector evaluated the adequacy of preventive measures and contingency actions for dealing with RCP seal events.

Both ANO units used Byron-Jackson RCPs, with the N-9000 seal assembly installed for Unit 1 and the SU type seal installed for Unit 2. Both seal assemblies had a mechanical sealing arrangement composed of three equally staged hydrodynamic seals. The Unit 2 RCP seal assembly differed slightly from that of the Unit 1 design in that the Unit 2 RCPs employed a fourth stage seal termed a low-pressure vapor seal. The Final Safety Analysis Report stated the vapor seal was qualified to withstand full RCS pressure in the static condition and during RCP coast down with all three main seal stages failed.

For both units, the seal assembly was cooled by circulating the controlled bleed off (CBO) through a coiled tube heat exchanger called the Integral Heat Exchanger (IHX). The IHX was integral with the pump case and was cooled by intermediate cooling water (ICW) for Unit 1 and component cooling water (CCW) for Unit 2. Seal coolant recirculation was performed by the RCP auxiliary impeller located directly below the seal cartridge.

In addition to the seal cooling from IHX/ICW, Unit 1 RCP seals were normally cooled by seal injection from the RCS charging system (makeup and purification system). Each seal cooling method had sufficient cooling capacity to compensate for a loss of the other without seal degradation. The inspector also noted that this seal cooling method provided advantages over relying solely upon IHX/ICW cooling by providing cooled, purified water and, thereby, reducing the probability of seal failures from RCS debris or crud.

RCP seal emergencies were addressed in Unit 1 AOP 1203.31, Revision 5, "RCP and Motor Emergency." Selected portions of this AOP were reviewed by the inspector and revealed a well developed and comprehensive procedure for a multitude of seal events. AOP 1203.31 addressed seal degradation, failures, and simultaneous loss of seal injection and seal cooling. Each of these conditions were addressed through symptoms with immediate and followup actions.

For seal degradations, the AOP provided sufficient detail to analyze seal cavity pressure oscillations for determining acceptable limits for seal stage differential pressure. Also, the procedure provided limits for coolant temperature, CBO rates, and seal cooldown rates.

The inspector reviewed AOP 1203.31 for assurance that blocked seal filters or failed seal injection control valves were addressed adequately. Blocked seal filters or strainers and failed control valves were event precursors for RCP seal failures experienced at other nuclear facilities. AOP 1203.31 properly identified the possibility of a clogged filter and the action required for opening of Seal Injection Filter (F-2) Bypass Valve MU-41. Also, the AOP called for opening of Bypass Valve MU-1207-3, if RCP seal injection flow (FV-1207) had failed closed. In the event seal injection was unavailable, Unit 1 RCP seals would receive adequate cooling from the IHX.

For the simultaneous loss of seal injection and seal cooling, AOP 1203.31 clearly delineated actions for restoring adequate seal cooling via ICW. ICW Booster Seal Cooling Pumps P-114A or -B were required to be placed in service to increase heat removal from reactor coolant passing through the IHX. A time limit of 2 minutes was set in the AOP for restoring seal injection or seal cooling. If cooling could not be restored within 2 minutes, an immediate action of tripping the affected RCP was prescribed. Based on control room observations, the inspector noted that control room operators exhibited good sensitivity and attention to RCP seal cooling when surveillances that could affect seal injection were being conducted.

The inspector also reviewed selected portions of relevant Unit 1 EOPs for maintaining seal integrity. Unit 1 EOPs for blackout and degraded power were reviewed. EOP 1202.08, Revision 1, "Blackout," instructed the operator to restore ICW and Seal Cooling Pumps P-114A or -B after re-energization of Safeguards Buses A3 and A4. The blackout procedure referenced AOP 1203.31 for simultaneous loss of seal injection and seal cooling flow. EOP 1202.07, "Degraded Power," also addressed seal injection restoration and re-establishment of CBO. Seal injection restoration was covered by EOP 1202.12, "Repetitive Tasks." In general, Unit 1 EOPs addressed RCP seal issues very well.

No deficiencies were found during the Unit 1 RCP seal AOP/EOP review. The diversity of seal cooling methods and adequately developed AOP/EOPs were noted as a strength.

Unit 2 RCPs used injectionless seal cooling. The RCP seal cooling was dependent exclusively on operability of the IHX, which cools unfiltered reactor coolant extracted directly from the RCS. The IHX was cooled by CCW, which was a nonsafety load and was initially unavailable under certain design-basis event conditions such as a loss of offsite power (LOOP).

Unit 2 had a seal injection path that was normally isolated and unavailable at power. This normally isolated pathway was from the chemical and volume control system (CVCS) charging pumps. For RCP seal cooling restoration, the inspector questioned Unit 2 operators on the availability of CVCS seal injection given a LOOP or a loss of CCW independent of a LOOP. Operators responded that the CVCS seal injection path was used during RCP startup for fill and vent activities and was isolated for normal operations. Manipulation of CVCS seal injection valves would require containment entry and extensive manual valve alignment. Since there was no alternate cooling method available, the loss of CCW would allow hot reactor coolant to circulate up through the RCP seals.

RCP seal emergencies were addressed in Unit 2 AOP 2203.025, Revision 5, "RCP Emergencies." This procedure was reviewed by the inspector. AOP 2203.025 focused on CCW operability and seal performance parameters. If the CCW system was lost, AOP 2203.025 permitted a 10-minute limit on the operation of RCPs to protect the seals from degradation. This contingency action required stopping all RCPs and initiating a reactor trip if CCW could not be restored. Operators were also instructed to check differential pressure across each seal stage. AOP 2203.025 contained a limit of no more than one failed seal for continued plant operation. Limits on RCP vapor seal pressure, CBO temperature and leakage, and seal cooldown rates were also addressed in the procedure.

The inspector also reviewed selected portions of Unit 2 EOPs which addressed a loss of seal cooling or degraded seal performance. EOP 2203.016, Revision 5, "Excess RCS Leakage," clearly instructed the operator to check the RCP seals for proper staging pressures and directed the operator to perform AOP 2203.025 in conjunction with the EOP.

EOP 2202.008, "Station Blackout," and EOP 2202.007, "Loss of Offsite Power," were briefly reviewed. Since Unit 2 RCP seal cooling was maintained only via the CCW system, these EOPs relied upon restoration of electrical sources in order to re-establish CCW flow to the RCPs. Explicit instructions were provided for CBO temperatures (180°F limit) in the event RCP restart was desired. For RCP restart, each procedure provided for verification that the RCP bleedoff valves (2CV-4846-1 and 2CV-4847-2) to the volume control tank were open to establish adequate flow.

singular cooling method for Unit 2 RCP seals and lack of cooling diversity not optimal due to the unavailability of CVCS seal injection for loss of CCW events and the potential for debris entry into the seal assembly from unfiltered reactor coolant. However, for the selected portions reviewed, the Unit 2 AOP/EOPs were to adequately developed for dealing with the current Unit 2 seal cooling design configuration.

No deficiencies were identified during the Unit 2 RCP seal AOP/EOP review.

3.2.2 Unit 2 - SG Inspection Following Tube Leak

Following the March 9 leak in SG A (see Section 4.2), the licensee developed a plan for locating the leak and inspecting the SGs. Using helium testing, the leak was located in Tube 67-09. Confirmatory eddy current examinations were performed using both the bobbin coil and rotating pancake coil techniques. These examinations identified that a 360° circumferential defect was present in Tube 67-109 at approximately 0.19 inches above the tube sheet. Bobbin coil examinations of the six tubes surrounding Tube 67-109 did not identify any other indications.

The bobbin coil examination data that was obtained from Tube 67-109 during the prior refueling outage (2R8) was also reviewed by the licensee. This review revealed the presence of an apparent indication at the failure location, which had not been identified for further investigation by either of the two eddy current examination analysts who had performed independent reviews of Refueling Outage 2R8 Tube 67-109 data. A reanalysis of the bobbin coil examination data that was obtained during Refueling Outage 2R8 was subsequently performed by the 2R8 eddy current examination contractor. This reanalysis identified an additional six tubes with indications near the tube sheet on the hot leg side.

As a result of the tube leak and its location, the licensee initiated rotating pancake coil examinations of 50 percent of the tubes on the hot leg side at the top of the tube sheet area in both SGs. The examination scope subsequently expanded to 100 percent at this location as a result of the number of indications detected. A 20 percent inspection of the SG A cold leg tubes at the top of the tube sheet was also performed with no indications identified.

3.2.2.1 Review of Refueling Outage 2R8 examination Data and Procedures

The inspector reviewed the following documents that were applicable to Refueling Outage 2R8 eddy current examinations of the SG tubing:

° Procedure 1092.073, "SG Integrity Program - Unit 2," Revision 1

° Special Work Plan 2409.286, "Inservice Inspection by W in ANO-2 A&B RSG Tubing," Revision 0

° Westinghouse Procedure MRS 2.42 GEN-30, "WL-II and SM-10W Operating Procedure," Revision 2

° Westinghouse Procedure DAT-GYD-001, "Data Analysis Guidelines," Revision 4

In addition, the inspector reviewed the contractor's eddy current examination report for Refueling Outage 2R8 and the examination tape for Tube 67-109. The inspector concluded from review of the tape that the analysts should have identified the indication for further evaluation.

Attachment 1 to Procedure 1092.073, Revision 1, provided specific analysis guidelines for ANO, Unit 2, SG inspection as a supplement to Westinghouse Procedure DAT-GYD-001. This attachment required both reporting of flaws having 10 percent or greater through-wall degradation and reporting of flaws with less than 10 percent through-wall degradation as having no detectable degradation. The attachment also required that, in the event the analyst was unable to characterize and/or size an indication, a graphical record of the indication should be made and forwarded with a technical description to the lead analyst for disposition. The failure of both primary and secondary analysts to identify the identifications in accordance with procedural requirements is an apparent violation of Criterion V of Appendix B to 10 CFR Part 50. However, the violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII of the NRC Enforcement Policy.

During review of the eddy current examination contractor's report for Refueling Outage 2R8, anomalies were noted with respect to documentation of calibrations. The inspector observed that data acquisition personnel were inconsistent in recording required, initial, 4-hourly, and end-of-tape calibrations. The inspector determined from a sample of six tapes that the calibrations were, in fact, performed and that the anomalies were indicative simply of minor documentation deficiencies. The inspector also noted one tape where the same individual had acted both as a primary analyst and resolution analyst (i.e., an individual designated as responsible for resolving differences noted between primary and secondary analysts' reports). While this practice was not specifically prohibited by Westinghouse Procedure DAT-GYD-001, Revision 4, it reflected a lack of appropriate independence. The licensee documented these issues on QAFR 92-036 and forwarded the QAFR to the contractor for resolution.

3.2.2.2 Review of Licensee Refueling Outage 2R8 Eddy Current Examination Oversight

The inspector reviewed Procedure 1000.061, Revision 5, "Control of Site NDE," and noted that the procedure included provisions for performance of audits and surveillances of ANO contractor nondestructive examination activities. The inspector requested that Refueling Outage 2R8 audit and surveillance reports of the eddy current examination contractor be provided. One quality assurance surveillance report was located in response to this request. This report indicated that a review was performed of completed eddy current examination job order packages and verified that they contained applicable data such as calibration reports and inspection personnel certifications. The inspector did not consider this oversight scope to be appropriate for effective identification of contractor performance problems. This was considered a weakness.

3.2.3 Unit 1 - Incorrect Lock Switch in Reactor Protection System Channels A, B, C, and D

The licensee identified that potentially incorrect lock switches were installed in the reactor protection system Channels A, B, C, and D shutdown bypass circuitry on Condition Report CR-1-92-196. The lock switches contained incorrect plating material on the contacts. B&W Service Bulletin No. 92-01 indicated that the failure of one of the switches does not constitute a safety concern. However, the bulletin further stated that the failure of the switch to rotate out of shutdown bypass when manipulated could result in an inadvertent reactor trip. The licensee performed a detailed review of their particular application of the key switches and the associated sequence of operations during startup and shutdown. They concluded that an inadvertent trip due to tarnished keyswitch contacts during startup or shutdown was not credible.

No problems were identified by the inspector.

3.2.4 Units 1 and 2 - Business Plan Backlog Reduction Goals

The inspector reviewed the status of the plan for reducing the backlog of open QAFR and open industry events. Both efforts were substantially ahead of schedule. This was viewed as a strength.

4. <u>UNITS 1 AND 2 - ONSITE FOLLOWUP OF EVENTS (93702)</u>

4.1 <u>Unit 1 - Notification of Unusual Event (NOUE) - Transport of an Injured Contaminated Worker Off Site</u>

On March 9, Unit 1 declared an Unusual Event at 8:15 p.m., under the requirements of 10 CFR Part 50.72. The licensee declared the unusual event because a contaminated worker was transported off site to a medical facility.

Plant management informed the inspectors that the worker sustained back injuries from an approximate 10-foot fall. The worker fell from a permanent ladder affixed at the 335-foot elevation near the quench tank in the Unit 1 reactor building. The injured individual was contaminated at a level approximately 100 counts per minute (cpm) above background levels. The injured worker was transported off site by ambulance to St. Mary's Regional Medical

Center in Russellville, Arkansas. Medical diagnosis indicated that the patient had suffered a compression fracture of the No. 12 thoracic vertebrae.

Unit 1 control room operators received immediate radio notification of the injury at 7:25 p.m. The licensee properly classified the event as a NOUE per Section 9.1 of Procedure 1903.010, "Emergency Action Level Classification." After successful decontamination of the injured individual, the NOUE was terminated at 8:50 p.m. During the event, the NRC Operations Center and the inspector were properly notified as well as the Arkansas Department of Health.

Information was transmitted via radio among the Unit 1 control room, security, and the emergency medical response team. Unit 1 control room operators exerted good command and control over the situation with clear instructions and lines of communication. ANO upper management and an inspector were present when medical attention was administered to the injured individual at the Unit 1 reactor building equipment hatch in preparation for transporting the individual off site.

When questioned on the root cause, the licensee stated that fatigue had been ruled out as probable cause since the worker had just come on shift and had not worked the previous day. In addition, no deficient conditions of the ladder were identified as a possible explanation for the accident. The licensee's internal investigation attributed the accident to personnel error.

The inspector expressed concern to ANO plant management over the number of industrial safety accidents involving personnel injuries during the refueling outage activities. After the NOUE, ANO management attention to industrial safety practices yielded reductions in personnel injuries throughout the remainder of the inspection period.

4.2 Unit 2 - SG Tube Leak Event

On March 9 at 7 p.m., Unit 2 shut down to repair an SG tube leak. The inspectors witnessed control room activities, shutdown preparations, and the eventual power descent during this tube leak event.

At approximately 12:30 p.m., while at 100 percent power, operators noted a step increase in radiation readings from the main condenser off-gas radiation monitor followed by an increase in SG blowdown activity levels. After analyzing the off-gas samples and conducting RCS mass balance calculations, the leakage was quantified at approximately 0.25 gallons per minute, with the SG A determined to be the source of the leak. TS 3.4.6.2(c) required plant shutdown if SG tube leakage exceeded 0.5 gallons per minute from a single SG.

Operators entered AOP 2203.038, "Primary to Secondary Leak," due to the SG B liquid radiation levels trending upwards. The affected A SG blowdown radiations levels did not initially increase as would be expected, due to a malfunctioning pressure regulating valve in the blowdown sample line that reduced sample flow. This malfunction initially caused some confusion with the operators. After correcting the SG A Blowdown sample flow, the operators received more expected readings. Operators reset the secondary system radiation alarm setpoints for the SG A radiation monitor to 1500 cpm, the SG B radiation monitor to 400 cpm, and the condenser off-gas monitor setpoint to 50,000 cpm to enable alarm indication to reflect any substantial degradation of the tube leak. These actions were performed in accordance with the station procedures and were considered a strength.

Inspectors questioned the operations staff on shift for the root cause of the defective condition and the associated misdiagnosis. Pressure Regulators 2PCV-5920A and -21A maintain constant pressure to the SG blowdown sampler lines for the SG A and B radiation monitors. Constant sample flow is necessary for SG blowdown radiation trends to have meaning to control room operators, and blowdown radiation trend changes were proportional to blowdown flow changes. Prior to the event, Pressure Regulator 2PCV-5920A was defective, which allowed sample pressure and flow rate to oscillate. To compensate for this deficiency, the root supply valve to the radiation monitors was throttled in order to stabilize sample flow. Sample flow through the radiation monitors was low enough during the tube leak event to render increases in SG A Sample (blowdown) Monitor 2RITS-5854 as undetectable. However, SG B Sample (blowdown) Monitor 2RITS-5864 began to trend upward leading operators to initially believe the tube leak originated in SG B. The SG B blowdown activity increase was due to the fact that SGs A and B feed into common systems such as the main condenser and SG blowdown system. These cross-connected systems resulted in the increased activity levels originating from the SG A eventually being reflected in SG B blowdown activity levels when secondary inventory was returned to SG B.

Operators questioned the readings of the SG blowdown monitor since condenser off-gas radiation levels increased significantly relative to SG B radiation monitor increases. Control room operators also noted that the Main Steam Line A radiation monitor had a step change increase concurrent with increases in the condenser off-gas monitor. The Main Steam Line B radiation monitor showed no increase during the event.

The control room supervisor dispatched an operator to investigate the monitor and determine if the sampling system was operating properly. The operator found that the pressure regulator had failed and that flow to the monitor could only be established by bypassing the regulator. Upon completing the realignment, the SG A blowdown monitor activity level readings increased as expected and corresponded to condenser off-gas activity levels.

Based on the licensee's internal investigation (Condition Report CR-2-92-055) and clarifying discussions with the inspectors, the licensee concluded that even though there were no TS associated with this condition, the misdiagnosis of the affected SG during an SG tube leak event could have serious consequences. The licensee's corrective actions included a recommendation for replacement of the suspect pressure regulators with a more reliable type. In addition, the licensee stated an intent to verify the operability of the SG blowdown monitors once per shift.

The licensee performed nuclear chemistry analysis of grab samples from the condenser off-gas system per Revision 5 of Procedure 1604.013, "Measurement of Primary To Secondary Leak Rate," for leak rate determination and positive identification of the affected SG. In addition, the licensee used argon-41 correlation results to obtain faster assessment of leak rate changes. The inspectors questioned the nuclear chemist on the secondary system iodine-131 dose equivalent (IDE) levels for periods prior to and after the plant shutdown. The licensee responded that the SG A IDE peak level preceding plant shutdown was 3.76 E-6 microcuries per cubic centimeter (uC/cc) and 1.15 E-3 uC/cc after shutdown. SG B peak IDE levels before and after shutdown were 2.90 E-8 uC/cc and 1.80 E-6 uC/cc, respectively. These secondary system activity levels were less than the TS 3.7.1.4 limit of 1.0 E-1 micocuries per gram.

Despite TS limits for SG leakage not being exceeded, the licensee decided to commence a plant shutdown at 7 p.m. The reactor was manually tripped at 8:21 p.m. Several precautionary measures were taken so to minimize the potential tube leak effects during the shutdown. Operators isolated the turbine driven emergency feedwater pump steam supply from the affected SG, maintained condenser vacuum via the auxiliary boiler, and restricted the use of the atmospheric dump valves to prevent any potential offsite release.

Communications and support between Units 1 and 2 were excellent during the SG tube leak event. Unit 2 operations personnel terminated all Unit 1 outage activities that impacted Unit 2. Work being conducted in areas shared between both units, such as the turbine hall, was also terminated. Unit 1 supported the Unit 2 shutdown by using Unit 1 auxiliary boiler steam to maintain vacuum in the Unit 2 main condenser.

In addition, the communications between the Unit 2 operations staff and ANO plant management were excellent. A shift turnover occurred during the event at 3:30 p.m. The operations staff addressed whether to relieve the on-shift crew as scheduled. The licensee evaluated the situation and concluded that current conditions had stabilized sufficiently to proceed with the normal shift turnover. The crew brief was thorough and the oncoming shift assisted in the determination of SG A being the source of the leak. AOP 2203.38 was adhered to by both crews during the tube leak event.

The licensee noted that the primary-to-secondary leak had been previously identified; however, the leak rate was minimally detectable and could not be quantified. During the Unit 2 refueling outage in April of 1991, the licensee attempted to locate the leaking tube by pressuring the secondary side of the SG with helium and utilizing a gas probe to search for the leaking tube. The tube defect was not of sufficient size to be detected using this method.

The inspectors considered the ANO staff's actions for dealing with the tube leak event to be commendable. Lessons learned and corrective actions for coping with the defective pressure regulator on the SG sampling system were dispositioned appropriately. Timely and conservative actions contributed to minimizing the extent of the leak and its potential consequences. The licensee's decision to commence a plant shutdown prior to approaching TS limits was evidence of prudent measures undertaken to protect public health and safety.

4.3 Unit 1 - Service Water (SW) Spill During Surveillance

Prior to Refueling Outage 1R8, the licensee had observed a significant pressure drop in the 18-inch, carbon steel SW line, due to excessive corrosion build-up. As a result, the licensee coated the inner piping wall with epoxy during Refueling Outage 1R8 and developed a surveillance requirement to ensure adequate epoxy integrity. This surveillance required the SW line to be de-watered and utilized video equipment to perform a visual examination of the epoxy lining for delamination and degradation effects.

In order to de-water the SW line during Refueling Outage 1R10, the licensee utilized an 18-inch polyurethane pig that was pushed using 8-psig of air, thus forcing the water in the SW piping from the emergency cooling pond discharge to the auxiliary building. At the auxiliary building, water was removed from the line utilizing a centrifugal de-watering pump taking suction on the SW piping and discharging back to the circulating water flume and to the lake. Isolation of the SW return header was accomplished by closing Valve CV-3823.

Valve CV-3823, a motor operated 18-inch butterfly valve, was later determined to have a portion of its flexible seat separated from the disk, which allowed the valve to leak. This resulted in water being discharged to two locations in the radiological controlled area of the auxiliary building: 335-foot elevation where SW return header pipe replacement was being performed and in the decay heat vault room where disassembly of a decay heat cooler for ECT was in progress.

Approximately [illegible]-30 gallons of SW was spilled where the SW return header pipe replacement was in progress. The water was collected to radwaste tanks via drains and the residual water was wiped up by a decontamination [illegible] within 20 minutes.

Approximately 100 gallons filled the SW side of Decay Heat Cooler E-35A and no water was spilled to the decay heat vault room floor. The remaining water in the SW line was discharged to the circulating water flume via the dewatering pump and the emergency feedwater line.

The inspector determined the licensee's response to the spill was appropriate.

5. MONTHLY MAINTENANCE OBSERVATION (62703)

Station maintenance activities for the safety-related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with the TSs.

5.1 Unit 2 - Local Leak Rate Testing (LLRT) of Electrical Penetration 2E-54 (Job Order (JO) No. 00[illegible]5338)

Unit 2 experienced a sharp increase in nitrogen leakage associated with seven electrical penetrations since plant shutdown. A significant pressure drop, from 60 to 0 psig in about 30 seconds, was noted from Electrical

Penetration 2E-67. The licensee initiated Condition Report 2-92-0058 and JO No. 00665338, which required LLRT on seven electrical penetrations, including Penetration 2E-54.

On March 24, the inspector observed the performance of Procedure 2304.015, Revision 12, Plant Change 1, "Local Leak Rate Testing Electrical Penetrations." This test was used to determine the source of the leak and to determine the leak rate at Electrical Penetration 2E-54.

The LLRT of Electrical Penetration 2E-54, which employed the make-up flow method, required the use of a portable rotameter test panel and a remote nitrogen bottle.

The technicians pressurized Penetration 2E-54 through the rotameter test panel and individually observed each rotameter from highest to lowest range for flow indication. The low range rotameter indicated a flow of 6500 standard cubic centimeters per minute (SCCM). The inspector also noted audible leakage from Penetration 2E-54 while the test was conducted. The technicians snoop checked all compression fittings on Penetration 2E-54 and found no detectable leakage. The source of the leakage was detected through the outer cup seal on Module G of the penetration. The technicians recorded the test pressure (68.7 psia), test temperature (74°F), and rotameter flow. Data collected from the test parameters was used to calculate (via thermodynamic equation) an actual flow rate of 6472.3 SCCM.

The Unit 2 systems engineer was informed of the leak subsequent to the determination of the leak source. The engineer appeared in the test area and visually verified the location of the leak on Penetration 2E-54. Electrical Penetration 2E-54 was tagged with a deficiency tag and a job request was initiated.

The inspector verified that all test equipment was within its required calibration period prior to performance of the LLRT. The inspector noted that the technicians were knowledgeable and conducted the test in a professional manner.

The inspector attended Corrective Action Review Board meetings following the LLRT of 2E-54 because the inspector was concerned of containment integrity implications associated with 10 CFR Part 50, Appendix, J guidelines. Results of the Corrective Action Review Board identified a total of nine penetrations leaking nitrogen outside of containment. A conservative administrative leakage limit of 50 SCCM was established for each penetration. The licensee stated that this limit serves as a indicator to the operators for tracking total containment leakage to ensure TS 3.6.1.2 limits are not exceeded.

The licensee stated that a definite root cause for seal degradation had not been determined, but a probable cause was aging. Management decided to temporarily repair the leaking seals by removing the module retaining ring, applying environmentally qualified sealant to the ring, and replacing the ring. The licensee stated that the temporarily repaired seals would be replaced during the next refueling outage.

The inspector determined that the licensee has made appropriate corrective action plans based on the data available. The LLRT was performed correctly according to approved procedures.

5.2 Unit 1 Make-up and Letdown Flow Indication Calibration (JO No. 861263)

On March 16, the inspector observed calibration of Unit 1 Make-up and Letdown Flow Indication (FI-1236). The inspector reviewed Procedure 1304.67, Revision 2, "Make-up Flow and Letdown Calibration," for technical content and discrepancies with no technician errors or procedural deficiencies noted. The inspector found that a listing of applicable test equipment, limits and precautions, and prerequisites were adequately incorporated. Input and output requirements with tolerances were also incorporated in tabular form.

The instrument and control supervisor and instrumentation technician adequately briefed the inspector on the scope of the procedure and described the method that the test equipment would be implemented. The inspector verified that calibration of all instrumentation was within the calibration dates. Prior to job performance, the technician obtained appropriate authorization from the Unit 1 outage desk and control room operator to commence work.

The technician removed three component modules from the non-nuclear instrumentation cabinet per Procedure 1304.67, Revision 2, and bench calibrated all modules. The modules were within the procedural tolerances and were replaced in the cabinet. Third person verification was completed satisfactorily.

No problems were identified.

5.3 Unit 1 - Removal of RCP D Motor Housing (JO No. 8660000)

On March 26, the inspector observed removal of RCP D motor housing per Procedure 1005.02, Revision 0. The inspector also observed worker practices inside containment during removal of the motor housing.

The RCP D had sustained damage to the upper thrust and journal bearings during pump coastdown testing on the morning of February 29, while the plant was in hot shutdown. Removal of the motor housing was required to replace damaged bearings and to access the RCP impeller, seal package, and bowl for component replacement and inspection purposes.

Prior to the lift, the inspector interviewed the crane operator. The contracted operator understood the scope of Procedure 1005.02, the number of hold points required during the lift, and the distances from the pump to the motor housing associated with the hold points. The inspector noted that the procedure was located near the operator if needed for reference.

The total lifting time of the motor was approximately 4 hours. The majority of the lift time was spent clearing the motor of components (i.e., scaffolding, transmitters, sensing lines, etc.) attached to the cavity walls or around the once through steam generator. Motor clearance was achieved by the spotters pushing the motor housing clear of components that obstructed the motor housing's travel path. Additional manpower (scaffolders) was added to the crew to move temporarily erected structures which might impede the lifting process. When the housing cleared the cavity, the lift was slow and steady with minimal motor housing rotation and swing. The inspector noted that the crew was efficient in coordinating efforts to correct problems (i.e., stand misalignment and obstructions) encountered during the lift.

The inspector noticed weak ALARA practices exhibited by individuals observing the lift. Protective clothing hoods were not secured under the chins of some personnel. This practice increased the potential for spreading contamination to the facial area. It was also noted that personnel were sitting on stairs adjacent to the staging area while the lift was in progress. The stairs would be considered a potentially contaminated area since the bottom of rubber boots were the most potentially contaminated area of protective clothing. The inspector noticed individuals loitering in the proximity of posted storage racks holding radioactively tagged articles in red bags. A potential for unnecessary additional exposure existed with these individuals since the area posted a "No loitering near storage racks" statement. These ALARA practices were considered a weakness.

5.4 Unit 1 - Removal and Replacement of RCP D Rotating Assembly and Seal Cartridge (JO No. B6599)

The inspector observed video tapes of the removal of the RCP D rotating assembly, which appeared to be well coordinated. The inspector also directly observed portions of the transport of the replacement rotating assembly from the machine shop to the equipment hatch. The inspector observed dirt on the wooden supports, which the licensee planned to use to support the RCP internals during transporting.

The inspector brought the dirt to the attention of the licensee and the licensee covered the dirt with plastic prior to setting the RCP internals on the wooden support. The licensee stated a general cleaning of the internals was planned prior to installation. The planned cleaning alleviated the inspector's foreign material exclusion concerns. However, further review of the licensee's cleanliness controls for handling stainless steel is planned and will be tracked as Inspection Followup Item 313-92007-2.

5.5 Summary of Findings

Unit 2 plans for electrical penetration repair are appropriate based on the data available. The LLRT was performed correctly according to approved procedures.

Unit 1 make-up and letdown flow indication calibration was successfully performed, without technician errors or procedural deficiency.

Weak ALARA practices were observed during the removal of the Unit 1 RCP D motor housing.

6. BIMONTHLY SURVEILLANCE OBSERVATION (61726)

The inspectors observed the TS required surveillance testing on the systems and components listed below and verified that testing was performed in accordance with TS and the licensee's implementing procedures.

6.1 Unit 1 - SW System Loop II Hydrostatic Testing (JO No. 852451)

On March 26, the inspector participated in the walkdown inspection of the portion of the Loop II SW system being hydrostatically tested in accordance with Special Work Plan 1409.409. Interviews with plant personnel indicated the test boundary was changed because of difficulties encountered while attempting to install blind flanges at the inlet and the outlet of Room Coolers VUC-1C and VUC-1D. The cooler isolation valves, which were verified open when the test alignment was established, were closed.

After repositioning the cooler isolati... valves, the licensee continued with filling, venting, and pressurizing th... ,stem. The test director planned to initiate a temporary change to the instruction if the problem with the blank flanges could not be resolved and the correct boundary b... reestablished prior to test completion.

TS 6.8.1 required, in part, that written procedures shall be established, implemented, and maintained covering surveillance and test activities of safety-related equipment.

Step 8.2.1 of Special Work Plan 1409.409, "SW System Loop II Hydrostatic Test (2nd 10 YR Cycle)," Revision 0, required that blank flanges be installed at the inlet/outlet flanges of coolers VUC-1C and VUC-1D.

Procedure 1092.189, "10 Year ISI Hydrostatic/Pneumatic Test Program Implementation," specified in Section 6.2.4.D that filling and venting of the system will be performed when all the system alterations have been completed.

Loop II of the SW system was filled, vented, and pressurized to hydrostatic test pressure without installing blank flanges at the inlets and outlets of Coolers VUC-1C and -1D.

This failure to follow procedures is an apparent violation (VIO 313-92007-01).

The licensee initiated Condition Re... CR-1-92-0228 to address the problem. The licensee planned to provide tra... to operations personnel on the conduct of maintenance, control of maintenance, and procedure control. The licensee also planned to revise Procedure 1092.189 to incorporate guidelines for pre-job briefing prior to the performance of hydrostatic testing. The licensee subsequently prepared and approved a temporary change to the test instruction. The test was performed in accordance with the revised instruction. The licensee stated the reduction in test boundary did not cause a breach of their inservice testing criteria. Based on a review of the completed and planned corrective actions, the inspector determined no further response to this violation was required.

No further problems were identified.

7. OPERATIONAL SAFETY VERIFICATION (71707)

The inspectors routinely toured the facility during normal and backshift hours to assess general plant and equipment conditions, housekeeping, and adherence to fire protection, security, and radiological control measures. Ongoing work activities were monitored to verify that they were being conducted in accordance with approved administrative and technical procedures and that proper communications with the control room staff had been established.

During tours of the control room, the inspectors verified proper staffing, access control, and operator attentiveness. TS limiting conditions for operation were evaluated. The inspectors examined status of control room annunciators, various control room logs, and other available licensee documentation.

7.1 Unit 1 - SOPP Implementation

During the inspection period, the inspector evaluated plant conditions against the licensee's SOPP. In all cases, necessary equipment was available as required. This plan substantially exceeded TS requirements and provided increased protection during various outage conditions. The licensee's development and use of their SOPP was viewed as a strength.

7.2 Unit 2 - RCS Drain and Midloop Operations

On March 12, the inspector observed Unit 2 operators commence draining the RCS. Control room activities, station procedures, and reduced inventory/midloop operations were reviewed. Reduced inventory was defined as RCS level below 65 inches as measured from the bottom of the RCS hot leg.

The licensee performed RCS draining in accordance with Procedure 2103.011, Revision 16, "Draining The RCS." Level instrumentation provided to operators included indication from RCS Refueling Level Transmitters 2LT-4791/2LT-4792 and local level indication from tygon tubing. An operator was stationed in the Unit 2 RB in radio communications with the control room, to monitor the tygon tube RCS level.

The inspector questioned operators on the calibration required for level instrumentation. The two level transmitters were by procedure to be calibrated at least once per 12-hour period. Tygon tube inspections were performed to check for indications such as leaks, kinks, and air bubbles. Resetting of RCS Hi/Lo alarm setpoints were also addressed by Procedure 2103.011. Operators utilized control room indications of RCS temperature from the core exit thermocouples via Temperature Indicator 2TI-4793.

AOP 2203.029 was established to address a loss of the operating shutdown cooling pump as a result of vortexing or cavitation. AOP 2203.029 was clearly referenced in the draining procedure as a course of corrective action for shutdown cooling (SDC) pump trouble. Procedure 2103.011 also provided an attachment with an SDC vortexing curve. This curve defines regions of acceptable and unacceptable operation when comparing SDC flow with RCS level. In addition, an operator was stationed at the SDC pump for 30 minutes following RCS level perturbations. This operator's responsibility was to listen for abnormal pump noises indicative of pump cavitation and report to the control room. In addition, the field operator continuously monitored the in-service SDC pump during draining evolutions.

A dedicated SDC licensed operator with no concurrent duties was assigned to monitor SDC parameters through control room indications. One train of shutdown cooling was in service with the second SDC train available during RCS draining. The inspector observed that operators were cognizant of the significance of shutdown risk and were routinely informed of the time-to-boil aspect of reduced inventory. The licensee continuously recalculated the RCS time-to-boil/core-uncovery during RCS draining and midloop operations. The parameters and information to perform the calculation were provided in Procedure 1015.008, Revision 5, "Unit 2 Shutdown Cooling System Control." This procedure also included tables for decay heat generation correction factors post-shutdown (on 1-hour intervals) and RCS level, temperature, and conditions (open or intact) for estimates of time-to-boil/core-uncovery.

During RCS draining, the inspector observed that control room traffic was at a minimum and restricted access was enforced. At 15-minute intervals, the control room checked with the tygon tube level observer for verification and recording of RCS level. Results were recorded in station logs for reduced inventory.

Midloop operations were performed at an RCS level of approximately 24 inches above the bottom of the RCS hot leg. The minimum RCS level for SDC was 19 inches. All control room operators were cognizant of the proper RCS level for conducting midloop operations.

These conservative safety precautions and practices continued while the unit was conducting midloop operations. The licensee has a well developed RCS draining procedure. No deficiencies were identified during Unit 2 RCS draining.

7.3 Unit 1 - Reactor Building Cooling (RBC) System

The review of the RBC system depicted fan/cooling coil units located in the reactor building (RB) that provide building cooling during normal and accident conditions. The normal cooling medium to the coils is nonsafety-related chilled water from a cooling unit located outside the RB. SW from Lake Dardanelle provides the cooling source during accident conditions. In the event of an engineered safety feature actuation signal (ESFAS), Valves CV-3814 and -3815, 10-inch air operated cooler outlet valves, open and permit SW to flow through the cooling units. In addition, an engineered safety feature actuation signal shifts a damper such that the cooling unit's fan directs flow through the coils cooled by SW. Valves CV-3814 and -3815 are located on the discharge of Coolers VCC-2A, -2B, -2C, and -2D, respectively.

During Refueling Outage 1R10, a job request was initiated when, during routine surveillance, audible leakage was detected at Valves CV-3814 and -3815. These valves were subsequently removed and the valve internals were visually inspected to determine the cause of the leakage. Visual indicated approximately 3 inches (5 percent) of the valve seat's O-ring missing on both valves. The licensee concluded that the missing portion of the rubber seating surface accounted for the audible leakage of SW through the valve.

The licensee stated Valves CV-3814 and -3815 do not perform a containment isolation function in accordance with 10 CFR Part 50, Appendix J, and, therefore, do not require LLRT. However, prior to Refueling Outage 1R9, a cooler tube leak (CR 1-90-0072) caused the licensee to analyze the effects of the RBC system's potential to passively increase offsite dose. The licensee assumed that, if a loss of coolant accident occurred with subsequent fission product escape from the RCS to the reactor building concurrent with a significant cooler tube leak and failure of either Valves CV-3814 or -3815 being capable to isolate the leak from outside of the RB, then a possible increase in offsite dose might occur due to contaminated SW being returned to the lake. The licensee stated that the driving force for fission product release through the SW system is containment pressure being momentarily greater than SW system pressure in the initial phases of the design basis accident. SW was considered part of the Seismic Class I system and, since it was determined that the RBC system had the potential to passively increase offsite dose, the licensee decided to include administrative leak testing of Valves CV-3814 and -3815 concurrent with 10 CFR Part 50, Appendix J, during subsequent outages.

The licensee determined that SW flow in either loop through Valves CV-3814 or -3815 decreases the likelihood of fission product escape through the applicable (open) valve during a loss of coolant accident in conjunction with failure of the aforementioned components. The inspector concluded that the licensee was conservative in minimizing potential increases in offsite dose by performing leak tests on Valves CV-3814 and -3815.

7.4 Unit 2 - Main Generator Operation

During routine observation in the Unit 2 control room on March 4, the licensee informed the inspector that the main generator voltage had been reduced to 21.5 KV at the request of the dispatcher to assist with a high voltage condition on the grid. The inspector asked the engineering department to determine the bases of the 21.7 KV value listed on the operating logs.

The 21.7 KV value was the minimum generator output voltage assumed in the Millstone analysis. Engineering reviewed the calculation and identified the worst case scenario. When 21.5 KV was used in the worst case scenario, no problems were identified. Therefore, this particular case was not safety significant. However, the inspector remained concerned that the 21.7 KV limit was viewed by the operating organization as a target. The operations log did not inform the operator that 21.7 KV was the minimum voltage assumed in a required analysis, and the voltage should not be reduced at the dispatcher's request below the minimum. The operations department shared the inspector's concern and clarified the log by adding precautionary notes describing the basis for required minimum generator output voltage.

7.5 Unit 1 - Chemical Decontamination During Coastdown

The licensee was unable to perform a planned hydrogen peroxide flush during shutdown to Refueling Outage 1R10 because of the failure on RCP D. The flush procedure was only qualified for use with RCPs C and D. The licensee did perform early boration and was successful in removing over 1000 curies of cobalt-58 and cesium at the start of Refueling Outage 1R10. This reduced the source term and was expected to lower total dose received during the outage. The early boration was viewed as a strength.

8. REFUELING OUTAGE ACTIVITIES (60710)

8.1 Unit 1 - Defueling

On March 14, the inspector observed the licensee's defueling activities. The inspector reviewed fuel movement procedures, operations, and plant conditions. Also, the inspector performed a walkdown of the platform surrounding the refueling cavity and the main fuel handling bridge.

Fuel movement was performed by qualified B&W services personnel. The refueling senior reactor operator on shift was knowledgeable of fuel movement safety limits and Procedure 1506.001, Revision 11, "Fuel Handling."

No deficiencies were identified during the defueling review.

8.2 Unit 1 - Spent Fuel Pool and Fuel Spring Inspection

Inspection of the spent fuel pool area and observance of fuel spring inspection was performed on March 17. No deficiencies were noted.

The inspector verified that housekeeping measures were invoked through the establishment of a roped off fuel assembly handling tool lay-down area and designation placards being posted indicating areas as such. Appropriate radiological controls with sufficient health physics personnel support were also established. Operators were knowledgeable about the uses of various components and systems utilized in the spent fuel pool area and were also knowledgeable as to the requirements of TS 3.8.16 for restricted fuel assembly enrichment in the spent fuel pool.

The spring inspector was an Entergy employee from Jackson. The inspector viewed ANO's utilization of an expert in spring inspection from Entergy's headquarters office as a strength. The Entergy inspector utilized a camera and light submerged in the spent fuel pool with video equipment and video monitor on the refueling bridge to document, inspect springs, and verify fuel assembly identification numbers. No defective or missing springs were identified.

9. SUMMARY OF OPEN ITEMS

The following is a synopsis of the status of all open items generated in this inspection report:

Violation 313-92007-01, "SW System was Pressurized for Hydrostatic Testing With an Unauthorized Revised Test Boundary Established and Failure to Follow Procedures," was opened and closed.

Inspection Followup Item 313-920007-02, "Review of the Licensee's Ceanliness Controls for Handling Stainless Steel," was opened.

LER 368-92-001 was closed.

10. EXIT INTERVIEW

The inspectors met with members of the Entergy staff on March 19 and 31, 1992. The list of attendees is provided in paragraph 1 of this inspection report. At these meetings, the inspectors summarized the scope of the inspection and the findings.

ATTACHMENT

Acronyms and Initialisms

ALARA	as low as reasonable achievable
AOP	abnormal operating procedure
ANO	Arkansas Nuclear One
B&W	Babcock and Wilcox
CBO	controlled bleed off
CCW	component cooling water
cpm	counts per minute
CST	central standard time
CVCS	chemical and volume control system
ECT	eddy current examination
Entergy	Entergy Operations, Inc.
EOP	emergency operating procedure
ICW	intermediate cooling water
IDE	Iodine-131 dose equivalent
IHX	integral heat exchanger
JO	job order
KV	kilovolt
LER	licensee event report
LLRT	local leak rate testing
LOOP	loss of offsite power
NOUE	notice of unusual event
QAFR	Quality Audit Finding Report
RB	reactor building
RBC	reactor building cooling
RCS	reactor coolant system
RCP	reactor coolant pump
SCCM	standard cubic centimeters
SDC	shutdown cooling
SG	steam generator
SOPP	shutdown operations protection plan
SW	service water
TS	Technical Specification
uC/cc	microcuries per cubic centimeter
10 CFR 2	Part 2, Title 10, Code of Federal Regulations
10 CFR 50	Part 50, Title 10, Code of Federal Regulations
10 CFR 50.59	Section 59, Part 50, Title 10, Code of Federal Regulations
10 CFR 50.72	Section 72, Part 50, Title 10, Code of Federal Regulations
10 CFR 50.73	Section 73, Part 50, Title 10, Code of Federal Regulations