UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

May 6, 2009

Kevin T. Walsh, Vice President, Operations
Entergy Operations, Inc.
Arkansas Nuclear One
1448 S.R. 333
Russellville, AR 72802

Subject: ARKANSAS NUCLEAR ONE - NRC INTEGRATED INSPECTION REPORT 05000313/2009002 AND 05000368/2009002

Dear Mr. Walsh:

On March 23, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Arkansas Nuclear One, Units 1 and 2, facility. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 15 and again on May 6, 2009, with Mr. Berryman, General Manager, Plant Operations, and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The International Atomic Energy Agency conducted an Operation Safety Review Team Evaluation at Arkansas Nuclear One from June 15 through July 2, 2008. The Operation Safety Review Team's review and evaluation of the facility is documented in the Operation Safety Review Team Report (ML083440148), which is accessible from the NRC Web-site at www.nrc.gov/reading-rm/adams.html. During the Operation Safety Review Team evaluation, NRC personnel closely monitored the team activities and as a result have deemed it appropriate to provide baseline inspection credit in accordance with the guidance provided in Inspection Manual Chapter 2515, "Light-Water Reactor Inspection Program-Operations Phase," dated May 1, 2008, Section 08.05. Specific details are outlined in the corresponding sections of the report where credit was given.

This report documents two NRC-identified findings and four self-revealing findings of very low safety significance (Green). Two of these findings involved violations of NRC requirements. Additionally, one licensee-identified violation, which was of very low safety significance, is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as noncited violations, consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the violations or the significance of the noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 612 E. Lamar Blvd, Suite 400, Arlington, Texas, 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident

Inspector at the Arkansas Nuclear One facility. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV, and the NRC Resident Inspector at Arkansas Nuclear One. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, and its enclosure, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA G.Replogle for/

Jeff Clark, P.E.
Chief, Project Branch E
Division of Reactor Projects

Dockets: 50-313; 50-368
Licenses: DPR-51; NPF-6

Enclosure:
NRC Inspection Report 05000313/2009002;
05000368/2009002 w/Attachment

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RI:DRP/E	RI:DRP/E	SRI:DRP/E	SPE:DRP/E	C:DRS/OB
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MPShannon	TRFarnholtz	NFO'Keef	GEWerner	JAClark
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	05000313, 50-368
Licenses:	DPR-51, DPR-6
Report:	05000313/2009002 and 0500368/2009002
Licensee:	Entergy Operations, Inc.
Facility:	Arkansas Nuclear One, Units 1 and 2
Location:	Junction of Hwy. 64 W and Hwy. 333 South Russellville, Arkansas
Dates:	January 1 through March 24, 2009
Inspectors:	A. Sanchez, Senior Resident Inspector J. Josey, Resident Inspector S. J. Rotton, Resident Inspector K.Clayton, Senior Reactor Inspector, Division of Reactor Safety
Approved By:	Jeff Clark, P.E., Chief, Project Branch E Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000313/2009002; 05000368/2009002; 01/01/09 – 03/24/09, Arkansas Nuclear One, Units 1 and 2, Resident Report; Surveillance Testing, Event Follow-Up

The report covered a 3-month period of inspection by resident inspectors. One Green noncited violation of significance was identified, as well as one Green Severity Level IV noncited violation. Three Green findings are also documented in this inspection report. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors documented a self-revealing finding associated with the Unit 1 February 5, 2009, manual reactor trip. The unit was manually tripped because control rod drive mechanism cooling was lost when the head gasket on Service Air Compressor C-3A failed. The failure of the head gasket was caused by a reduction in torque applied on the head gasket bolts during maintenance. The applied torque values were lower than the torque values recommended by the vendor. The licensee entered this issue into their corrective action program as Condition Report ANO-1-2009-0225.

  The performance deficiency was more than minor because it was associated with the design control attribute of the Initiating Events Cornerstone and it directly affected the cornerstone objective to limit the likelihood of those events that upset plant stability during power operations. Using Inspection Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, this finding was determined to have very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding was determined not to have a crosscutting aspect because the decision to lower the torque value was made in 2001 and was not indicative of current plant performance (Section 4OA3.2).

- Green. The inspectors documented a self-revealing finding because an auxiliary operator failed to follow procedure instructions that prohibited the use of torque amplifying devices on plant valves. The operators used such a device on a main generator hydrogen skid valve and inadvertently disassembled the valve. The subsequent hydrogen leak started a fire. Control room operators manually tripped the reactor and entered Mode 3. The failure to follow the procedure in this instance was not a violation of NRC requirements because the hydrogen system was not safety related. The licensee entered this issue into their corrective action program as Condition Report ANO-1-2009-0254.

The finding was more than minor because it was associated with the Human Performance attribute of the Initiating Events Cornerstone and it directly affected the cornerstone objective to limit the likelihood of those events that upset plant stability during power operations, and is therefore a finding. Using the Inspection Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, this finding had very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding had a crosscutting aspect in the area of Human Performance associated with Work Practices [H.4(a)], in that licensee personnel failed to use human error prevention techniques, such as self and peer checks and STAR (stop, act, think, and review), and failed to stop in the face of uncertainty or unexpected circumstance to ensure that work activities were performed safely and without consequence. Specifically, the auxiliary operator did not use human error techniques, nor did the operator stop the hydrogen addition evolution when unexpected circumstance arose (Section 4OA3.3(b)).

- <u>Green</u>. The inspectors documented a self-revealing finding for the failure to properly implement the flow accelerated corrosion control program. Consequently, a nonsafety-related extraction steam drain line failed because of flow accelerated corrosion. Engineers had identified the line as being vulnerable to flow accelerated corrosion but did not monitor it. Engineers also failed to integrate relevant industry operating experience into the program. Operators had to reduce Unit 2 power and take the turbine off line in response to the event. The licensee entered this issue into their corrective action program as Condition Report ANO-2-2009-0319.

  The performance deficiency was more than minor because it affected the equipment performance attribute of the Initiating Events Cornerstone, and it directly affected the cornerstone objective to limit the likelihood of those events that upset plant stability during power operations. Using Inspection Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, this finding was determined to have very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The finding had a crosscutting aspect in the area of Problem Identification and Resolution associated with Operating Experience [P.2(b)], in that licensee personnel failed to implement and institutionalize operating experience through changes to station processes and procedures (Section 4OA3.4).

Cornerstone: Mitigating Systems

- <u>Green</u>. The inspectors identified a noncited violation of Technical Specification 5.4.1.a, “Procedures,” for an inadequate maintenance procedure governing reactor protection system Channel A flux/delta flux/flow trip circuit. Specifically, the instructions did not provide sufficient details concerning the tightening of screws on a circuit card during a surveillance. This resulted in improper maintenance which rendered the channel inoperable after it was returned to service. The licensee had previously identified problems with the adjustment of these screws. In addition, the inspectors identified a significant contributor to the event. The lead qualified technician on the job failed to follow a maintenance procedure and provide continuous supervision to a non-qualified technician that was performing the sensitive maintenance. The licensee entered this issue into their corrective action program as Condition Reports ANO-1-2009-0066 and ANO-1-2009-0464.

The performance deficiencies were more than minor because, if left uncorrected, they could result in more significant concerns. Specifically, during future surveillance and maintenance work, a reactor protection system circuit could again be rendered inoperable by inadequate maintenance and go undetected for a longer time period. In addition, unqualified individuals performing unsupervised maintenance could render various pieces of mitigating equipment inoperable or cause initiating events. Using the Inspection Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, this finding had very low safety significance because the finding: (1) resulted in a loss of operability of reactor protection system Channel A; (2) did not lead to an actual loss of safety function of the system or train; (3) did not result in the loss of one or more trains of nontechnical specification equipment; and (4) did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. This finding had a crosscutting aspect in the area of Problem Identification and Resolution, Corrective Action Program component [P.1(c)] because the licensee failed to thoroughly evaluate the problem such that the resolution addressed the causes – i.e., failure to properly supervise the trainee (Section 1R22).

Cornerstone: Miscellaneous

- Green. The inspectors identified a noncited Severity Level IV violation of 10 CFR 50.9, "Complete and Accurate Information," because the licensee provided inaccurate information to the NRC following a reactor trip. Specifically, while making a 10 CFR 50.72 report (for a site fire, which had prompted a manual reactor trip) the licensee informed the NRC headquarters operations officer (on a recorded line) that all control rods had fully inserted into the core. On the contrary, one control rod had failed to fully insert, although the reactor was in a shutdown condition. Operations personnel had failed to use 3-way communications when discussing the control rod positions during the event. After the licensee determined the actual control rod position, the information was not provided directly to the NRC. The information was considered material to the NRC's informational needs because the NRC may have initiated different short term response measures had the NRC known that one control rod was partially out. This issue was entered into the licensee's corrective action program as Condition Reports ANO-1-2009-0260 and ANO-1-2009-0281.

  The finding was more than minor because the information was material to the NRC's decision making processes. In accordance with Inspection Manual Chapter 0612, "Power Reactor Inspection Reports," the violation was subject to the traditional enforcement process because 10 CFR 50.9 violations impact the NRC's ability to perform its regulatory function. Using the Enforcement Policy, Supplement VII, "Miscellaneous Matters," the inspectors characterized the violation as a Severity Level IV violation because it did not meet the Severity Level I, II or III criteria. NRC management reviewed the finding and determined that it was of very low safety significance (Green). Because the violation was of very low safety significance and was entered into the corrective action program, this violation is being treated as a noncited violation, consistent with the NRC Enforcement Policy, Section VI.A. The finding had a crosscutting aspect in the area of Human Performance (Work Practices component) because operations personnel failed to utilize human error prevention techniques (3-way communication) when gathering information to provide to the NRC [H.4(a)] (Section 4OA3.3(a)).

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating at 100 percent power. On February 5, 2009, operators manually tripped the reactor in response to a loss of control rod drive mechanism cooling. On February 6, 2009, operators restarted the Unit 1 reactor and achieved approximately 90 percent power at 10:35 a.m. on February 7, 2009. On February 7, 2009, at 10:46 a.m., operators manually tripped the reactor due to a hydrogen fire in the turbine building at the turbine generator hydrogen add station. On February 13, 2009, Unit 1 was returned to 100 percent power. On March 3, 2009, Unit 1 reduced power to approximately 62 percent due to a request from the load dispatcher. On March 4, 2009, Unit 1 was returned to 100 percent power. The unit remained at 100 percent for the remainder of the inspection period.

Unit 2 began the inspection period operating at 100 percent power. On January 12, 2009, operators reduced Unit 2 power to approximately 65 percent due to a feedwater tube leak. The unit was shutdown and placed into Mode 3 on January 14, 2009, to effect repairs to feedwater Heater 2E-7B. Following repairs, operators returned the unit to 100 percent power on January 18, 2009. On February 7, 2009, Unit 2 was manually tripped due to an unisolable high pressure turbine extraction steam leak. The unit was restarted on February 8, 2009, and achieved 100 percent power on February 10, 2009. On February 28, Unit 2 power was reduced to approximately 89 percent to repair an emerging condenser tube leak. On March 1, 2009, the unit was returned to 100 percent power. On March 10, 2009, unit power was again reduced to approximately 83 percent power to support the removal of circulating water Pump B from service. On March 11, 2009, reactor power was increased to 87 percent due to cooler weather and better condenser vacuum margin. On March 13, 2009, Unit 2 main feedwater Pump A thrust bearing temperature increased and it was quickly removed from service. Due to the loss of the main feedwater pump, unit power was reduced to approximately 84 percent power. Just a couple of hours later, operations staff manually tripped the unit due to main feedwater Pump B steam generator flow control valve failing closed. On March 16, 2009, Unit 2 commenced a reactor startup. On March 19, 2009, Unit 2 achieved 100 percent power. The unit remained at 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 <u>Readiness for Seasonal Extreme Weather Conditions</u>

a. <u>Inspection Scope</u>

The inspectors performed a review of the licensee’s adverse weather procedures for seasonal extreme low temperature preparations. The inspectors: verified that weather-related equipment deficiencies identified during the previous year were corrected prior to the onset of seasonal extremes; and evaluated the implementation of the adverse weather preparation procedures and compensatory measures for the affected conditions before the onset of, and during, the adverse weather conditions.

During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Final Safety Analysis Report and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. Specific documents reviewed during this inspection are listed in the attachment. The inspectors also reviewed corrective action program items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Alternate AC diesel generator system
- Unit 2 safety-related battery rooms

These activities constitute completion of one readiness for seasonal adverse weather sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings of significance were identified.

.2 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility for March 10, 2009, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. The inspectors walked down Units 1 and 2 main transformer yards and the service water intake structure systems because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the Final Safety Analysis Report and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. The inspectors also reviewed a sample of corrective action program items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the corrective action program in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one readiness for impending adverse weather condition sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- March 18, 2009, Unit 1, Train B emergency core cooling system due to degraded Train A emergency core cooling system room drain valve

- March 20, 2009, Unit 1 turbine-driven emergency feedwater system while emergency diesel Generator K-4A was inoperable due to surveillance testing

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could affect the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, Final Safety Analysis Report, technical specification requirements, administrative technical specifications, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two partial system walkdown samples as defined in Inspection Procedure 71111.04-05.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- February 26, 2009, Unit 2, Fire Zone 2183-J, Upper north electrical penetration room
- March 12, 2009, Unit 2, Fire Zone 2084-DD, Upper south piping penetration and equipment room
- March 12, 2009, Unit 1, Fire Zone 120-E, Boric acid tank and pump room

The inspectors reviewed areas to assess if licensee personnel had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features, in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to affect equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. Specific documents reviewed during this inspection are listed in the attachment.

The International Atomic Energy Agency conducted an Operation Safety Review Team Evaluation at Arkansas Nuclear One from June 15 through July 2, 2008. In accordance with Inspection Manual Chapter 2515, "Light-Water Reactor Inspection Program-Operations Phase," dated May 1, 2008, Section 08.05, the annual minimum inspection sample in this area has been reduced to a minimum of 3 samples per quarter and a maximum of 18 samples per year.

These activities constitute completion of three quarterly fire-protection inspection samples as defined in Inspection Procedure 71111.05-05.

b. Findings

No findings of significance were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On February 16, 2009, the inspectors observed an unannounced fire brigade activation due to a fire in the Unit 2 turbine building at the hydrogen seal oil skid, Fire Zone 2200-MM. The observation evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies, openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were: (1) proper wearing of turnout gear and self-contained breathing apparatus; (2) proper use and layout of fire hoses; (3) employment of appropriate fire fighting techniques; (4) sufficient firefighting equipment brought to the scene; (5) effectiveness of fire brigade leader communications, command, and control; (6) search for victims and propagation of the fire into other plant areas; (7) smoke removal operations; (8) utilization of preplanned strategies; (9) adherence to the preplanned drill scenario; and (10) drill objectives.

On March 19, 2009, the inspectors observed fire brigade training at the onsite fire training center. Inspectors specifically evaluated the actual use of hoses and fire hydrant, the implementation of search and rescue techniques, and the proper donning and use of turnout gear and self-contained breathing apparatus.

These activities constitute completion of one annual fire-protection inspection sample as defined in Inspection Procedure 71111.05-05.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On March 19, 2009, the inspectors observed a crew of licensed operators in the plant's Unit 2 simulator to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance
- Crew's clarity and formality of communications
- Crew's ability to take timely actions in the conservative direction
- Crew's prioritization, interpretation, and verification of annunciator alarms
- Crew's correct use and implementation of abnormal and emergency procedures
- Control board manipulations

- Oversight and direction from supervisors

- Crew's ability to identify and implement appropriate technical specification actions and emergency plan actions and notifications

The inspectors compared the crew's performance in these areas to pre-established operator action expectations and successful critical task completion requirements. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one quarterly licensed-operator requalification program sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk significant systems:

- March 10, 2009, Unit 1, Instrument air system.

The inspectors reviewed events such as where ineffective equipment maintenance has resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices

- Identifying and addressing common cause failures

- Scoping of systems in accordance with 10 CFR 50.65(b)

- Characterizing system reliability issues for performance

- Charging unavailability for performance

- Trending key parameters for condition monitoring

- Ensuring proper classification in accordance with 10 CFR 50.65(a)(1) or (a)(2)

- Verifying appropriate performance criteria for structures, systems, and components classified as having an adequate demonstration of performance through preventive maintenance, as described in 10 CFR 50.65(a)(2), or as requiring the establishment of appropriate and adequate goals and corrective actions for systems classified as not having adequate performance, as described in 10 CFR 50.65(a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one quarterly maintenance effectiveness sample as defined in Inspection Procedure 71111.12-05.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed licensee personnel's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- February 17, 2009, Unit 2, Maintenance work window for the turbine-driven emergency feedwater Pump 2P-7A

- February 19-20, 2009, Units 1 and 2, emergency cooling pond fish eradication project

- March 4, 2009, Unit 1, maintenance work window for high pressure injection Valve CV-1284

- March 4-5, 2009, Unit 2, tri-annual plant protection system Channel A test and reactor trip breaker replacement with main steam isolation signal pushbutton troubleshooting activities

- March 11-13, 2009, Unit 2, low pressure safety injection Pump 2P-60A and emergency diesel Generator 2K-4A work window and surveillance postponed due to Emergent Circulating Water Pump 2P-3B work

The inspectors selected these activities based on potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that licensee personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When licensee personnel performed emergent work, the inspectors verified that the licensee personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of five maintenance risk assessments and emergent work control inspection samples as defined in Inspection Procedure 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- December 3, 2008, Unit 1, reactor building spray Pump P-35A following operations inadvertently running the pump with Suction Valve CV-1407 closed for approximately 1 minute

- January 28, 2009, Unit 1, pressurizer heaters due to a failure of a heater, which caused the heater Bank Rub-14 Supply Breaker B-5656B to open

- February 16, 2009, Units 1 and 2, service water systems following the identification of the clogged Unit 1 service water Pump P-4B discharge strainer due to gambusia affins (minnows) in the emergency cooling pond

- February 24, 2009, Unit 2, main steam isolation actuation pushbutton and plant protection system Channel D following an unexpected half-leg trip while a chart recorder was being inserted into the panel directly above the pushbutton

The inspectors selected these potential operability issues based on the risk-significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that technical specification operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and Final Safety Analysis Report to the licensee’s evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four operability evaluations inspection samples as defined in Inspection Procedure 71111.15-04

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the following temporary/permanent modifications to verify that the safety functions of important safety systems were not degraded:

- February 11, 2009, Unit 1, permanent modification performed to the emergency switchgear room chillers

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, timing, heat removal, control signals, equipment protection from hazards, operations, flow paths, pressure boundary, ventilation boundary, structural, process medium properties, licensing basis, and failure modes for the modification listed below. The inspectors verified that modification preparation, staging, and implementation did not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions; postmodification testing will maintain the plant in a safe configuration during testing by verifying that unintended system interactions will not occur, systems, structures and components' performance characteristics still meet the design basis, the appropriateness of modification design assumptions, and the modification test acceptance criteria will be met; and licensee personnel identified and implemented appropriate corrective actions associated with permanent plant modifications. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample for permanent plant modifications as defined in Inspection Procedure 71111.18-05

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following postmaintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- December 4, 2008, Unit 1, decay heat removal Pump P-34A following inboard and outboard seal replacement activities during Refueling Outage 1R21

- December 10, 2008, Unit 1, emergency feedwater Pump P-7A following outage maintenance and governor speed control system calibration

- December 12, 2008, Unit 1, Group 7 control rod programmer replacement

- February 3, 2009, Unit 2, emergency feedwater Pump 2P-7A following maintenance on the control room speed Controller 2HIC-0336-2

- February 15-16, 2009, Unit 2, containment building spray Pump 2P-35B following troubleshooting and repair of a loose connection in the pump trip circuit that led to the pump not being able to be stopped from the control room

- February 25, 2009, Unit 1, electrical equipment room emergency air conditioning System VCH-4A, following unplanned maintenance to replace degraded motor leads

- March 14, 2009, Unit 1, boric acid Pumps P-39A and P-39B following discharge check valve replacement for both pumps to eliminate a long standing operator work around

The inspectors selected these activities based upon the structure, system, or component's ability to affect risk. The inspectors evaluated these activities for the following (as applicable):

- The effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed

- Acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate

The inspectors evaluated the activities against the technical specifications, the Final Safety Analysis Report, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of seven postmaintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Final Safety Analysis Report, procedure requirements, and technical specifications to ensure that the five surveillance activities listed below demonstrated that the systems, structures, and/or components tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the significant surveillance test attributes were adequate to address the following:

- Preconditioning
- Evaluation of testing impact on the plant
- Acceptance criteria
- Test equipment
- Procedures
- Jumper/lifted lead controls
- Test data
- Testing frequency and method demonstrated technical specification operability
- Test equipment removal
- Restoration of plant systems
- Fulfillment of ASME Code requirements
- Updating of performance indicator data
- Engineering evaluations, root causes, and bases for returning tested systems, structures, and components not meeting the test acceptance criteria were correct
- Reference setting data
- Annunciators and alarms setpoints

The inspectors also verified that licensee personnel identified and implemented any needed corrective actions associated with the surveillance testing.

- January 25, 2009, Unit 1, 18-month calibration of reactor protection system Channel A
- February 2, 2009, Unit 1, emergency feedwater Pump P-7A

- February 11, 2009, Unit 2, in-service test of emergency feedwater Pump 2P-7A

- February 26, 2009, Unit 2, emergency diesel Generator 2DG2 semi-annual fast start surveillance test

- March 5, 2009, Unit 2, tri-annual plant protection system Channel A test

Specific documents reviewed during this inspection are listed in the attachment.

The International Atomic Energy Agency conducted an Operation Safety Review Team Evaluation at Arkansas Nuclear One from June 15 through July 2, 2008. In accordance with Inspection Manual Chapter 2515, "Light-Water Reactor Inspection Program-Operations Phase," dated May 1, 2008, Section 08.05, the annual minimum inspection samples in this area was reduced to 14 samples and the annual maximum was reduced to 19 samples.

These activities constitute completion of five surveillance testing inspection samples as defined in Inspection Procedure 71111.22-05.

b. Findings

Introduction. The inspectors identified a Green noncited violation of Technical Specification 5.4.1.a, "Procedures," for an inadequate maintenance procedure governing reactor protection system Channel A flux/delta flux/flow trip circuit. Specifically, the instructions did not provide sufficient details concerning the tightening screws on a circuit card during a surveillance. This resulted in improper maintenance which rendered the channel inoperable after it was returned to service. The licensee had previously identified problems with the adjustment of these screws. In addition, the inspectors identified a significant contributor to the event. The lead qualified technician on the job failed to follow a maintenance procedure and provide continuous supervision to a nonqualified technician that was performing the sensitive maintenance.

Description. On January 13, 2009, using Work Order 51676088, station instrumentation and control personnel performed an 18-month calibration of reactor protection system Channel A. Following this maintenance, the channel was returned to service and operated correctly for approximately 30 minutes before abnormal indications were observed by control room staff. Because of the abnormal indications, operators declared the instrument inoperable and bypassed the channel. The licensee entered this condition into their corrective action program as Condition Report ANO-1-2009-0058.

The following day, the licensee performed troubleshooting and found that the screws holding down the "scaled delta flow module" had been over-tightened during the noted maintenance. Screws holding the module in place were found over-tightened to the point of causing abnormal tension on connectors on both the module and cabinet connections. To resolve the condition, the screws were loosened and retightened hand tight plus one quarter turn with a screwdriver. The instrument then worked properly.

While the licensee did not identify previous instances where over-tightening had caused erratic operation of these instruments, the licensee had noted that under-tightening had caused operational problems previously. The licensee had not provided specific step by step instructions in the work procedures because they believed that the tightening of these screws was within the skill of the craft. To resolve the issue, the licensee planned to change applicable calibration procedures to add instructions so that the screws will be tightened in a consistent manner to ensure proper operation. The inspectors considered the original Work Order 51676088 inadequate because it did not contain sufficient instructions to ensure proper completion of this critical task. The licensee entered this finding into their corrective action program as Condition Report ANO-1-09-0066.

The lead technician for this job was familiar with the proper method of tightening these specific module screws. However, he was not performing the work himself but was supervising a trainee under instruction. The lead technician had provided verbal instructions to the trainee on the proper method of tightening the module screws. But, the lead technician did not observe this critical task and allowed the trainee to perform the step unsupervised while he looked ahead in the procedure.

The inspectors found that the licensee's apparent cause had failed to identify a significant contributor to this finding. Specifically, the inspectors identified that the lead technician had failed to follow site procedures governing the supervision of a trainee under instruction. For example, Procedure EN-MA-105, "Planning," Section 3[12] required, in part:

> The craftsperson performing this work is either qualified to perform the work or is under the supervision of a qualified individual.

Station Procedure EN-TQ-204, "On-The-Job-Training and Evaluation," Section 5.1[2], Revision 9, required, in part, that:

> When trainees are assigned to perform a task on actual plant equipment for training or evaluation, a person who is qualified on the task should provide <u>direct and continuous</u> [emphasis added] oversight to verify proper task performance.

Finally, Procedure EN-TQ-212, "Conduct of Training and Qualification," Revision 2, states, in part:

> Entergy Nuclear employees and supplemental personnel independently perform only those tasks or jobs which they are qualified to perform. For typical craft or technician tasks, personnel are considered to be working independently unless another qualified individual or a technically competent supervisor or manager provides continuous, direct (line of sight) oversight of the activity.

Contrary to the above, the trainee was not qualified to perform the work on the reactor protection system circuit and another qualified individual was present but he failed to provide continuous, direct (line of sight) oversight of the activity. The licensee entered this concern into their corrective action program as Condition Report ANO-C-2009-0464.

<u>Analysis</u>. The failures to: (1) have an adequate maintenance work instruction, (2) have the lead technician continuously observe the trainee during critical work tasks in accordance with site procedures, and (3) identify that one of the instrument failure causes included improper trainee oversight were performance deficiencies. The performance deficiencies were more than minor because, if left uncorrected, they could result in a more significant concern. Specifically, during future surveillance and maintenance work, a reactor protection system circuit could again be rendered

inoperable by inadequate maintenance and go undetected for a longer time period. In addition, unqualified individuals performing unsupervised maintenance could render various pieces of mitigating equipment inoperable or cause initiating events. Using the Inspection Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, this finding had very low safety significance because the finding: (1) resulted in a loss of operability of Reactor Protection System Channel A; (2) it did not lead to an actual loss of safety function of the system or train; (3) it did not result in the loss of one or more trains of nontechnical specification equipment; (4) it did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. This finding had a crosscutting aspect in the area of Problem Identification and Resolution, Corrective Action Program component [P.1(c)] because the licensee failed to thoroughly evaluate the problem such that the resolution addressed the causes (i.e. failure to properly supervise trainee).

Enforcement. Arkansas Nuclear One, Unit 1 Technical Specification 5.4.1.a, “Procedures,” requires, in part, that written procedures be established implemented and maintained that are recommended in Regulatory Guide 1.33, Revision 2, Appendix A, “Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors,” February 1978. Appendix A of the regulatory guide, Section 9, stipulates procedures for performing maintenance that can affect the performance of safety-related equipment. The licensee provided a procedure for the conduct of maintenance on the reactor protection system Channel A flux/delta flux/ flow trip channel in Work Order 51676088. Contrary to the above, Work Order 51676088 was inadequate, in that it did not provide specific instructions governing the tightness of reactor protection system module screws, which was a critical maintenance task. The failure to provide an adequate procedure constituted a failure to meet the technical specification requirement. Because this finding was of very low safety significance and was entered into the licensees corrective action program, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000313/2009002-01, Inadequate Procedure for Reactor Protection System Maintenance.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

.1 Training Observations

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on March 19, 2009, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post evolution critique for the scenario. The focus of the inspectors’ activities was to note any weaknesses and deficiencies in the crew’s performance and ensure that the licensee evaluators noted the same issues and entered them into the corrective action program. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.06-05.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the fourth Quarter 2008 performance indicators for any obvious inconsistencies prior to its public release in accordance with Inspection Manual Chapter 0608, “Performance Indicator Program.”

This review was performed as part of the inspectors’ normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings of significance were identified.

.2 Unplanned Scrams per 7000 Critical Hours (IE01)

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours performance indicator for Units 1 and 2 for the period from the third Quarter 2007 through the fourth Quarter 2008. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, was used. The inspectors reviewed the licensee’s operator narrative logs, issue reports, event reports and NRC integrated inspection reports for the period of September 2007 through December 2008 to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two unplanned scrams per 7000 critical hour samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.3 Unplanned Scrams with Complications (IE02)

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications performance indicator for Units 1 and 2 for the period from the third Quarter 2007 through the fourth Quarter 2008. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC integrated inspection reports for the period of September 2007 through December 2008 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two unplanned scrams with complications samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.4 Unplanned Power Changes per 7000 Critical Hours (IE03)

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Power Changes per 7000 critical hours performance indicator for Units 1 and 2 for the period from the third Quarter 2007 through the fourth Quarter 2008. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, maintenance rule records, event reports and NRC integrated inspection reports for the period of September through December 2007 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two unplanned transients per 7000 critical hour samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors reviewed attributes that included: the complete and accurate identification of the problem; the timely correction, commensurate with the safety significance; the evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews; and the classification, prioritization, focus, and timeliness of corrective actions. Minor issues entered into the licensee's corrective action program because of the inspectors' observations are included in the attached list of documents reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings of significance were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. The inspectors accomplished this through review of the station's daily corrective action documents.

The inspectors performed these daily reviews as part of their daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings of significance were identified.

.3 Selected Issue Follow-up Inspection: Extent of Condition Review for Missed Maintenance Rule Functional Failure Determinations Associated with the Alternate AC Emergency Diesel Generator

a. Inspection Scope

During a review of items entered in the licensee's corrective action program, the inspectors recognized a corrective action item documenting the failure to accurately classify and count maintenance rule functional failures for the alternate AC diesel generator. The inspectors selected this issue for review because the failure to accurately classify and count functional failures would have a negative impact on the station's ability to accurately monitor equipment performance. The inspectors reviewed and evaluated Condition Reports ANO-C-2008-1114 and ANO-2-2008-2099, the associated apparent cause evaluations, and corrective actions (taken and planned). The inspectors considered the following, as applicable, during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

These activities constitute completion of one in-depth problem identification and resolution sample as defined in Inspection Procedure 71152-05.

b. Findings

No findings of significance were identified.

.4 Selected Issue Follow-up Inspection: Unit 1 Alloy 600 Mitigation Project Exceeds Dose Estimate by Greater than 200 Percent of Predicted Dose

a. Inspection Scope

During a review of the licensee corrective action review board meeting agenda and subsequent meeting attendance, the inspectors recognized a corrective action item documenting the Unit 1 Alloy 600 Mitigation Project exceeding dose projections. The inspectors selected this issue because of occupational dose was in excess of the predicted and anticipated values. The inspectors considered the following, as applicable, during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 Unit 2 Unplanned Shutdown- January 14, 2009

a. Inspection Scope

On January 14, 2009, the inspectors responded to the Unit 2 control room due an unplanned, controlled reactor shutdown to repair Feedwater Heater 2E-7B tube leaks. Unit 2 was already as 65 percent in an attempt to remain at power and effect repairs on the feedwater heater. Operators reduced Unit 2 power to approximately 20 percent and manually tripped the reactor in accordance with normal operating procedures. The inspectors determined that the reactor was stable in Mode 3 and that there had been no complications during the shutdown. The inspectors discussed the event and the reactor condition prior to and following the shutdown with operators, shift manager, other operations management, and reviewed licensee's procedures and plant indications to verify proper operator actions and plant response. The inspectors also reviewed the initial licensee notification to verify that it met the requirements specified in NUREG-1022, "Event Reporting Guidelines," Revision 2.

b. Findings

No findings of significance were identified.

.2 Unit 1 Unplanned Shutdown - February 5, 2009

a. Inspection Scope

On February 5, 2009, the inspectors reported to the Unit 1 control room, that Unit 1 was manually tripped because of the loss of control rod drive mechanism cooling. The Service Air Compressor C-3A head gasket failed, which allowed compressed air to void the nonnuclear intermediate cooling water (nonsafety-related) loop and cause the loss of control rod drive mechanism cooling. The inspectors determined that the reactor was stable in Mode 3 and that there had been no complications during the trip. The inspectors discussed the event and the reactor condition prior to and following the trip with operators, shift manager, other operations management, and reviewed licensee's procedures and plant indications to verify proper operator actions and plant response. The inspectors also reviewed the initial licensee notification to verify that it met the requirements specified in NUREG-1022, "Event Reporting Guidelines," Revision 2. The inspectors also reviewed the licensee's posttrip report to assess the adequacy of the review and proposed corrective actions prior to plant restart.

b. Findings

Introduction. The inspectors documented a self-revealing finding associated with the Unit-1 February 5, 2009, manual reactor trip. The unit was manually tripped because control rod drive mechanism cooling was lost when the head gasket on Service Air Compressor C-3A failed. The failure of the head gasket was caused by a reduction in torque applied on the head gasket bolts during maintenance. The applied torque values were lower than the torque values recommended by the vendor.

Description. On February 5, 2009, the Unit 1 reactor was manually tripped from approximately 60 percent reactor power due to the loss of control rod drive mechanism cooling. At approximately 2:52 p.m., the control room received a service air compressor trouble alarm, followed by a control rod drive cooling flow low alarm. Operators entered Abnormal Operating Procedure OP-1203.003, "Control Rod Malfunction," and noted an increase in control rod drive stator temperatures. Operations commenced a reactor down power at 3:06 p.m. in an effort to help reduce temperatures. At 3:24 p.m., operators manually tripped the reactor from approximately 60 percent power due to increasing control rod drive stator temperatures.

At approximately 3:30 p.m. following the reactor trip, operators noted, in electronic logs, that Service Air Compressor C-3A had blown a head gasket, which introduced large quantities of air into the nonnuclear intermediate cooling water system resulting in cavitation of intermediate cooling water Pump P-33A and both control rod cooling pumps.

Normally, service air is supplied via a trailer mounted, temporary air compressor and the service air Compressors C-3A and C-3B are back up for service air. As far back as 1985, there have been instances where service air and instrument air compressors have introduced air into their cooling systems, nonnuclear intermediate cooling water system for Unit 1, and component cooling water for Unit 2 (neither cooling water system is safety related for this licensee). Since that time, the instrument air compressors for both units have been replaced with a different design (1992 and 1996, respectively) and no subsequent air intrusion events were noted due to compressor operation. On February 2, 2009, the temporary service air compressor for Unit 1 was tagged out for maintenance and service air Compressor C-3A was placed into service. On February 5, 2009, the head gasket failed resulting in the Unit 1 reactor trip.

The root cause investigation concluded that the licensee's engineering department evaluated and inappropriately approved a reduction in the torque values from the vendor manual recommendations in 2001, which were implemented in maintenance performed on Service Air Compressor C-3A in September 2007. The Engineering Request ANO-2001-1268 was initiated because maintenance performed on Service Air Compressor C-3B resulted in stripping the threads on one of the upper head cover plates. The vendor recommended value was 160 foot-pounds, while the modified value was 92 foot-pounds. During discussion with the vendor, it was discovered that this torque value was critical for proper gasket sealing. This inadequate torque on service air compressor was the root cause of the head gasket failure, resulting in the loss of control rod drive cooling and the manual reactor trip. All service air compressors for Unit 1 were immediately tagged out and are not currently in use.

The design deficiency for the instrument and service air compressors has been known to the licensee since 1985. In 1988 a design request was initiated to replace the air compressors to remove the possibility of introducing air into the before mentioned cooling systems. The instrument air compressors, which are of high risk and importance, were replaced while the replacement for the service air compressors, which are classified as a high critical component, but noncritical by the preventative maintenance program, went unfunded. The service air compressor system does not have an assigned system engineer to monitor or walkdown the system.

Analysis. The failure to properly understand the basis for the head gasket torque values before changing those values was a performance deficiency. The finding was more than minor because it was associated with the design control attribute of the Initiating Events Cornerstone and it directly affected the cornerstone objective to limit the likelihood of those events that upset plant stability during power operations. Using Inspection Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding had very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding did not have a crosscutting aspect because the decision to lower the torque value was made in 2001 and was not indicative of current plant performance

Enforcement. Since the service air compressor was not safety related, no violation of NRC requirements was identified. The licensee has entered this issue into their corrective action program as Condition Report ANO-1-2009-0225:
FIN 050000313/2009002-02, Inadequate Service Air Compressor Torque Value Led to Loss of Control Rod Drive Cooling and Manual Reactor Trip.

.3 Unit 1 Manual Reactor Trip - February 7, 2009

a. Inspection Scope

On February 7, 2009, the inspectors responded to the site following notification of a fire at the main generator hydrogen addition station which had prompted the licensee to manually trip the Unit 1 reactor from 90 percent reactor power. The inspectors arrived in the control room, received reports of the current status of the fire, and assessed the condition of the reactor. The inspectors determined that the reactor was stable in Mode 3 and received reports from the licensee that there had been no complications during the trip. The inspectors discussed the event and the reactor condition prior to and following the trip with operators, the shift manager, other operations management, and reviewed licensee's procedures and plant indications to verify proper operator actions and plant response. The fire lasted approximately 15 minutes and the licensee declared a Notification of an Unusual Event at 10:59 a.m. because a fire in the protected area lasted more than 10 minutes. Initial offsite notification was made at 11:09 a.m., within the first 15 minutes after declaration of the event. At 12:38 p.m. the licensee exited the Notification of an Unusual Event. The inspectors also reviewed the initial licensee notification to verify that it met the requirements specified in NUREG-1022, "Event Reporting Guidelines," Revision 2. The inspectors also reviewed the licensee's posttrip report to assess the adequacy of the review and proposed corrective actions prior to plant restart.

b. Findings

.1 Inaccurate Information Reported to the Headquarters Operations Officer

Introduction. The inspectors identified a (Green) noncited Severity Level IV violation of 10 CFR 50.9, “Complete and Accurate Information,” because the licensee provided inaccurate information to the NRC following a reactor trip. Specifically, while making a 10 CFR 50.72 report (for a site fire which had prompted a manual reactor trip) the licensee informed the NRC headquarters operations officer (on a recorded line) that all control rods had fully inserted into the core. On the contrary, one control rod had failed to fully insert although the reactor was in a shutdown condition. Operations personnel had failed to use 3-way communications when discussing the control rod positions during the event. After the licensee determined the actual control rod position, the information was not provided directly to the NRC. The information was considered material to the NRC’s informational needs because the NRC may have initiated different short term response measures had the NRC known that one control rod was partially out.

Description. On February 7, 2009, Unit 1 operations personnel manually tripped the reactor in response to a report of a fire at the main generator hydrogen addition station. While performing posttrip actions, operations personnel determined that the reactor was shutdown, however, they discovered that the rod bottom light for Rod 6 in Group 7 did not illuminate which is an indication that the rod did not fully insert into the core. Operations personnel subsequently checked the absolute position indication analog meter in the control room and noted that it appeared to indicate 0 percent. However, this instrument does not provide sufficiently clear indication to conclusively determine the actual control rod position.

A contributor to the violation included inadequate communications between the operations manager, who had made the report, and the control room staff. The operations manger had believed that all control rods were fully inserted when he made the report to the NRC. He had previously asked the control room staff if they had checked a different more reliable indication (in a different room). The operators misunderstood the question and replied in the affirmative (the subject instrument was checked). However, this was not factually correct, as the operators had only checked the analog meter previously mentioned. The operations manager then assumed that the control rod was fully inserted, when it was not. The licensee’s root cause determination found that the failure to properly use 3-way communications (an error prevention tool) contributed to this violation.

When the inspectors responded to the control room and inquired about the status of the plant, they were informed that a manual trip had been initiated and that the reactor was shutdown and all rods had fully inserted. Also, while making a report to the NRC Headquarters Operations Center in accordance with 10 CFR 50.72, as a result of a fire on site which had resulted in declaration of a Notice of an Unusual Event, the licensee reported that a manual trip had been initiated and that the reactor was shutdown and all rods had fully inserted. At no point did the licensee communicate to the NRC that a rod bottom light had not come on following the trip.

Subsequently, while reviewing plant computer data for control rod drive mechanism Group 7 Rod 6 to verify agreement between analog absolute position indication and the computer point, operations personnel noted that absolute position indication by plant computer was indicating the rod to be at 2.3 percent withdrawn. Operations personnel also noted that the 0 percent zone light for Group 7 Rod 6 was not lit, which was another indicator that the rod was not fully inserted. Based on this, operations initiated Condition Report ANO-1-2009-0260 to identify that the control rod had not fully inserted. However, the licensee did not correct the previous erroneous information that was provided to the NRC.

The inspectors reviewed Condition Report ANO-1-2009-0260 and informed the licensee that information officially provided to the NRC was not complete and accurate. The licensee entered this new concern into their corrective action program as Condition Report ANO-1-2009-0281.

Based on the observations and questions of the inspectors, on February 10, 2009, the licensee made an updated report to the NRC using NRC Form 361, "Reactor Plant Event Notification Worksheet." This updated report identified that the rod bottom light for Rod 6 in Group 7 did not illuminate following the trip on February 7, 2009, and it was verified by plant computer to have inserted to 2.3 percent withdrawn.

Analysis. The failure to provide the NRC with complete and accurate information was a performance deficiency. The finding was more than minor because the information was considered material to the NRC's decision making processes. In accordance with Inspection Manual Chapter 0612, "Power Reactor Inspection Reports," the violation was subject to the traditional enforcement process because 10 CFR 50.9 violations impact the NRC's ability to perform its regulatory function. Using the Enforcement Policy, Supplement VII, "Miscellaneous Matters," the inspectors characterized the violation as a Severity Level IV violation because it did not meet the Severity Level I, II, or III criteria. NRC management reviewed the finding and found that it was of very low safety significance (Green). Because the violation was of very low safety significance and was entered into the corrective action program, this violation is being treated as a noncited violation, consistent with the NRC Enforcement Policy, Section VI.A. The finding had a crosscutting aspect in the area of Human Performance (Work Practices component) because operations personnel failed to utilize human error prevention techniques (3-way communication) when gathering information to provide to the NRC [H.4(a)].

Enforcement. 10 CFR 50.9, "Complete and Accurate Information," requires, in part, that information provided to the NRC must be complete and accurate in all material respects. On February 7, 2009, the licensee informed the NRC headquarters operations officer (on a recorded line) that all control rods had fully inserted into the core. Contrary to the above, the information was not complete and accurate in all material respects because one control rod had failed to fully insert into the core. Because NRC management determined this violation to be of very low safety significance (Green) and it was entered into the corrective action program as Condition Report ANO-1-2009-0260, this violation is being treated as a Severity Level IV noncited violation, consistent with the NRC Enforcement Policy, Section VI.A: NCV 05000313/2009002-03, Failure to Provide Complete and Accurate Information to the NRC Following a Plant Trip.

.2 Hydrogen Fire in Unit 1 Turbine Building

Introduction. The inspectors documented a Green self-revealing finding because an auxiliary operator failed to follow procedure instructions and obtain the operation supervisor's approval prior to using a torque amplifying device on a hydrogen system valve. The operator used such a device and inadvertently disassembled the valve which started a plant fire. Control room operators manually tripped the reactor and declared a Notice of Unusual Event. The failure to follow the procedure was not a violation of NRC requirements because the hydrogen system was not safety related.

Description. On February 7, 2009, Unit 1 day shift operators attempted to add hydrogen to the main generator. The main generator uses hydrogen as a cooling medium and operators periodically add hydrogen to maintain hydrogen operating pressure within established limits. During the prejob brief, the shift technical advisor had recommended a peer check for the valve manipulations. The auxiliary operator, who performed the manipulations, was relatively inexperienced and had performed the procedural steps just two times previously, both prior to October 2008.

The auxiliary operator asked the waste control operator to perform a peer check for the hydrogen addition valve manipulations. However, the waste control operator was occupied with another activity and could not provide assistance. The auxiliary operator did not communicate the difficulty in obtaining a peer check to the shift technical advisor.

Operating Procedure OP-1106.002, "Generator Hydrogen System," Revision 25, Exhibit A, required the auxiliary operator to, in part, verify that Valve PCV-8311 (H_2-109) was in the open position. The auxiliary operator assumed that the valve was closed. However, it was a "normally open" valve and was already open. She attempted to reposition the valve to the open position but achieved no valve movement. She then attempted to close the valve with no success.

The auxiliary operator obtained a torque amplifying device (pipe wrench) to assist in opening the valve. The auxiliary operator applied it to the valve hand-wheel and began to turn the valve in the open direction. The auxiliary operator then observe valve hand-wheel movement. However, the operator was actually unscrewing the valve bonnet from the valve body. Eventually, the valve bonnet disengaged from the valve body. When this occurred, hydrogen gas leaked rapidly into the room. The auxiliary operator recognized the danger and evacuated the area. A fire initiated shortly thereafter. The auxiliary operator reported the fire to the control room.

The auxiliary operator had failed to follow station procedures regarding the use of torque amplifying devices. Operating Procedure OP-1015.001, Section 14, required, in part, if a torque amplifying device is used for manual valve operation, the operator must obtain the operations supervisor's permission prior to use. Contrary to the above, the auxiliary operator failed to obtain the necessary approval. If she had requested approval, the procedure would have invoked additional controls which would include a valve position evaluation. The licensee concluded that the failure of the auxiliary operator to follow Operating Procedure OP-1015.001 was the root cause for the event.

The International Atomic Energy Agency Operation Safety Review Team identified, in June 2008, that the licensee's frequent use of torque amplifying devices was an outlier compared to other facilities (see ML083440148). The team encouraged Arkansas Nuclear One to provide sufficient controls governing the use of torque amplifying devices to ensure their safe use. The licensee implemented a standing order to provide additional direction and ultimately updated Operating Procedure OP-1015.001 to reflect the new requirements. While training was provided to the operations staff to reinforce the new controls, this particular auxiliary operator was not sufficiently aware of the procedural restrictions.

Analysis. The failure of the Unit 1 auxiliary operator to follow plant procedures that governed the use of a torque amplifying device on a manual valve was a performance deficiency. The finding was more than minor because it was associated with the human performance attribute of the Initiating Events Cornerstone and it directly affected the cornerstone objective to limit the likelihood of those events that upset plant stability during power operations. Using the Inspection Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, this finding had very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding had a crosscutting aspect in the area of Human Performance associated with Work Practices [H.4(a)], in that licensee personnel failed to use human error techniques, such as self and peer checks and STAR (stop, act, think, and review), and failed to stop in the face of uncertainty or unexpected circumstance to ensure that work activities were performed safely and without consequence.

Enforcement. The hydrogen valve was not a safety-related component, so no violation of NRC requirements occurred. The licensee has entered this issue into their corrective action program as Condition Report ANO-1-2009-0254: FIN 05000313/2009002-04, Failure to Follow Procedure for Use of a Torque Amplifying Device on a Valve in the Generator Hydrogen System.

.4 Unit 2 Unplanned Down Power - February 7, 2009

a. Inspection Scope

On February 7, 2009, the inspectors responded to the Unit 2 control room following notification of a steam leak on the main turbine that had prompted the licensee to lower reactor power to allow the turbine to be taken off line. The inspectors observed control room operators, walk down control panels, and discussed the sequence of events with operators, shift manager, and other operations personnel and determined that the reactor responded as expected, no abnormalities occurred and that operators responded as licensee procedures and training would dictate. The inspectors also reviewed the initial licensee notification to verify that it met the requirements specified in NUREG-1022, "Event Reporting Guidelines," Revision 2.

b. Findings

Introduction. The inspectors documented a Green self-revealing finding for the failure to properly implement the flow accelerated corrosion control program. Consequently, a nonsafety-related extraction steam drain line failed because of flow accelerated corrosion. Engineers had identified the line as being vulnerable to flow accelerated corrosion but did not monitor it. Engineers also failed to integrate relevant industry operating experience into the program. Operators had to reduce Unit 2 power and take the turbine off line in response to the event. The licensee entered this issue into their corrective action program as Condition Report ANO-2-2009-0319.

Description. On February 7, 2009, while Unit 2 was operating at 100 percent power, operations personnel in the control room received a report of a steam leak in the turbine building. An auxiliary operator was dispatched to investigate this issue. During this investigation, it was determined that the steam leak was from a ruptured first stage extraction steam drain line which was unisolable with the turbine in operation. Based on this information, the licensee lowered reactor power to 20 percent and tripped the main turbine to isolate the leak and to facilitate repairs.

Subsequent investigation determined that Line 2GBD-92-1, a 1-inch diameter carbon steel pipe, was ruptured, which was downstream of Flow Orifice 2FO-0860 as detailed on station piping and instrument diagrams. This line was designed as a moisture removal line from the high pressure turbine steam chest draining into the extraction steam line.

Based on initial reviews and examination of the piping, the licensee determined that the failure occurred due to flow accelerated corrosion of the piping. The licensee performed a root cause analysis of this issue as documented in Condition Report ANO-2-2009-0319. During this evaluation, the licensee determined that the piping that had failed was listed in the station's flow accelerated corrosion program document, Engineering Request 95-R-2004-01, “ANO-2 Flow Accelerated Corrosion System Susceptibility Report,” Revision 2, as being susceptible to flow accelerated corrosion. However, the failed location was not listed as a specified test location. This was determined to be contrary to Station Procedure EN-DC-315, “Flow Accelerated Corrosion Program,” Revision 2, which specifically identified the need to include locations down stream of orifices in the monitoring population as well as directing that susceptible small bore piping inspections be ranked by priority. Furthermore, the licensee determined that the station's flow accelerated corrosion program had not implemented current industry recommendations for monitoring small bore piping and that available industry operating experience was not acted upon even though it was known about. Based on this information, the licensee determined the root cause of this issue to be that the flow accelerated corrosion program has a gap identifying critical wear areas in small bore piping down stream of orifices.

Subsequently, the licensee performed an extent of condition to determine other potentially susceptible locations on both Units 1 and 2. This review identified 17 locations on Unit 1, and 24 locations on Unit 2. These locations were ranked and a sample population was chosen for inspection. During these inspections, no other issues were identified with flow accelerated corrosion.

Analysis. The failure to follow Procedure EN-DC-315 and monitor locations downstream of orifices as well as develop a priority ranking system for small bore piping susceptible to flow accelerated corrosion was a performance deficiency. The finding was more than minor because it affected the equipment performance attribute of the Initiating Events Cornerstone, and it directly affected the cornerstone objective to limit the likelihood of those events that upset plant stability during power operations. Using Inspection Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, this finding had very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The finding had a crosscutting aspect in the area of Problem Identification and Resolution associated with Operating Experience [P.2(b)], in that licensee personnel failed to implement and institutionalize operating experience through changes to station processes and procedures.

Enforcement. The affected small bore steam piping was not safety related, therefore no violation of NRC requirements occurred. The licensee has entered this issue into their corrective action program as Condition Report ANO-2-2009-0391:
FIN 05000368/2009002-05, Failure To Follow Procedure For Flow Accelerated Corrosion Program.

.5 Unit 2 Manual Reactor Trip – March 13, 2009

a. Inspection Scope

On March 13, 2009, at approximately 10 p.m., inspectors responded to a pager notification that Unit 2 had initiated a manual reactor trip due to Main Feedwater Regulating Valve 2CV-740 failing closed. The inspectors arrived at the control room at approximately 10:20 p.m. and observed control room operators, walk down control panels, and discussed the sequence of events with operators, shift manager, and other operations personnel and determined that the reactor responded as expected, no abnormalities occurred, and that operators responded as licensee procedures and training would dictate. The inspectors also reviewed the initial licensee notification to verify that it met the requirements specified in NUREG-1022, "Event Reporting Guidelines," Revision 2. The inspectors also reviewed the licensee's posttrip report to assess the adequacy of the review and proposed corrective actions prior to plant restart.

b. Findings

No findings of significance were identified.

.6 (Closed) LER 05000368/2008001-00, "Containment Isolation Valve Inoperable Longer than Allowed by Technical Specifications as a Result of Personnel Error During Planning and Construction of Scaffolding." This LER was dispositioned in NRC Inspection Report 05000313/2008002; 05000368/2008002, Section 1R22. This LER is closed based on that inspection.

4OA5 Other Activities

1. Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors performed observations of security force personnel and activities to ensure that the activities were consistent with Arkansas Nuclear One's security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

2. Temporary Instruction 2515-172, “Reactor Coolant System Dissimilar Metal Butt Welds”

The following inspection activities associated with this temporary inspection were conducted October 27 through November 14, 2008, during a Unit 1 refueling outage. The documentation was inadvertently left out of NRC Inspection Report 05000313/2008005;05000368/2008005.

Portions of Temporary Instruction TI 2515/172, “Reactor Coolant System Dissimilar Metal Butt Welds” were performed at Arkansas Nuclear One, Unit 1, during 1RF21 in October and November of 2008. The reactor coolant system for this unit is carbon steel with stainless steel cladding and has the following dissimilar welds:

1. Two 10-inch pressurizer surge line nozzle welds (one for the pressurizer and one for the reactor coolant system), both mitigated during previous outages using a weld overlay process. Volumetric Category F weld, Visual Category is no longer applicable since each weld was mitigated

2. Two 3-inch pressurizer safety nozzles, both mitigated during previous outages using a weld overlay process. Volumetric Category F weld, Visual Category is no longer applicable since each weld was mitigated.

3. One 2.5-inch pressurizer power-operated relief valve nozzle, mitigated during previous outages using a weld overlay process. Volumetric Category F weld, Visual Category is no longer applicable since each weld was mitigated.

4. One 4-inch pressurizer spray nozzle, mitigated during previous outages using a weld overlay process. Volumetric Category F weld, Visual Category is no longer applicable since each weld was mitigated.

5. Two 14-inch core flood nozzles, both mitigated during this outage (1RF21) with a weld inlay process which is a repair within ASME guidelines and therefore required no relief request. Volumetric Category A welds, Visual Category is no longer applicable since both welds were mitigated.

6. One 12-inch decay heat nozzle, mitigated during this outage (1RF21) with a weld overlay process authorized by relief request ANO-R&R-011. Volumetric Category F weld, Visual category is no longer applicable since the weld was mitigated.

7. One 2.5 inch high pressure Injection nozzle that is a dual function nozzle for makeup (unmitigated, volumetric inspection conducted during Outage 1RF21 will be reviewed at a later date). Volumetric Category E, Visual Category is K.

8. Three 2.5-inch high pressure Injection nozzles (unmitigated and not inspected this outage, 1RF21). Volumetric Category I, Visual Category is K.

9. Four 28-inch reactor coolant pump inlet nozzles (unmitigated as of this outage, 1RF21). Volumetric Category I, Visual Category is K.

10. Four 28-inch reactor coolant pump outlet nozzles (unmitigated as of this outage, 1RF21). Volumetric Category I, Visual Category is K.

11. Four cold leg drain nozzles, 2.5-inch diameter for loop "A" and a 1.5-inch diameter for the remaining three loops "B" thru "D" (unmitigated as of this outage, 1RF21). These are not included in the MRP-139 program for Volumetric Categories. Visual Category is K until the end of this year when Code Case N-722 is approved. After this code case is approved, the visual categories within the MRP are no longer applicable.

03.01 Licensee's Implementation of the MRP-139 Baseline Inspections

a. MRP-139 baseline inspections: The inspectors observed performance and reviewed records of structural weld overlays and nondestructive examination activities associated with the licensee's pressurizer structural weld overlay mitigation effort. The baseline inspections of the pressurizer dissimilar metal butt welds were completed during Refueling Outage 1RF20 (the spring 2007 refueling outage).

b. At the present time, the licensee is not planning to take any deviations from the baseline inspection requirements of MRP-139, and all other applicable dissimilar metal butt welds are scheduled in accordance with MRP-139 guidelines.

03.02 Volumetric Examinations

a. The inspectors did not review the ultrasonic examination and eddy current examination records of the mitigated core flood nozzles because the licensee had not completed the weld inlay repair activities on these two nozzles during the inspection period. The inspectors reviewed the ultrasonic examination for the decay heat nozzle surface weld overlay mitigation that was done per approval of NRC Relief Request ANO-R&R-011. These examinations were conducted in accordance with ASME Code, Section XI, Supplement VIII, "Performance Demonstration Initiative," requirements regarding personnel, procedures, and equipment qualifications. No relevant conditions were identified during these examinations.

b. Inspectors reviewed records for the nondestructive evaluations performed on one of the pressurizer weld overlays. This effort was documented in Section 1R08 of NRC Inspection Report 05000313/2008005. Inspection coverage met the requirements of MRP-139 and no relevant conditions were identified.

c. The certification records of ultrasonic examination personnel were reviewed for those personnel that performed the examinations of the mitigated core flood nozzles, the decay heat nozzle, and the unmitigated dual function high pressure injection/make up nozzle. All personnel records showed that they were qualified under the EPRI Performance Demonstration Initiative.

d. No deficiencies were identified during the nondestructive examination.

03.03 Weld Overlays.

a. Review of welding activities associated with the weld inlay repairs made on the two core flood nozzles will receive in-office review at a later date.

b. The licensee submitted and received NRC authorization by letter dated June 18, 2008, for the use of 10 CFR 50.55a Relief Request ANO-R&R-011 "for relief from the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code at the Arkansas Nuclear One, Unit 1. Relief Request ANO1-R&R-011 is applicable to the structural weld overlay of the dissimilar metal weld of the hot leg nozzle to decay heat piping." This weld was mitigated during this outage (1RF21) using the full structural weld overlay process.

c. The licensee submitted and received NRC authorization by letter dated April 6, 2007, for the use of 10 CFR 50.55a Relief Request ANO-R&R-10 "for the use of full structural weld overlays on dissimilar metal welds of pressurizer nozzles at Arkansas Nuclear One, Unit 1." All six of these welds were mitigated during the previous outage (1R20) using the full structural weld overlay process.

d. Deficiencies have not been identified in the completed pressurizer full structural weld overlays.

03.04 Mechanical Stress Improvement

This item is not applicable because the licensee did not employ a mechanical stress improvement process.

03.05 Inservice Inspection Program

The licensee's MRP-139 Inservice Inspection Program will receive in-office review at a later date.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting Summary

On April 15, 2009, and on May 6, 2009, the inspectors presented the inspection results to Mr. Berryman, General Manager, Plant Operations, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

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

.1 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” requires, in part, that testing is performed under suitable environmental conditions. Suitable environmental conditions include those that are representative of expected standby configuration and the condition in which the equipment would be when required to perform its safety function. Contrary to the above requirement, on October 31, 2008, the licensee failed to assure that testing performed on Valve CV-3821 was performed under suitable environmental conditions. Specifically, the boundary valve leak test for Valves CV-3811, CV-3821, and SW-9 was performed multiple times, due to an unaccounted for temporary modification, prior to obtaining satisfactory test data for Valve CV-3821. This finding was determined to have very low safety significance because: (1) the finding was not a qualification deficiency that resulted in a loss functionality, (2) it did not lead to an actual loss of safety function of the system or train, (3) it did not result in the loss of one or more trains of nontechnical specification equipment, (4) it did not represent an actual loss of safety function of one or more nontechnical specification trains of equipment designated as risk-significant per 10 CFR 50.65 for greater than 24 hours, and (5) it did not screen as potentially risk-significant due to a seismic, flooding, or severe weather initiating event. This issue was entered into the licensee’s corrective action program as Condition Reports ANO-1-2008-1618 and ANO-1-2008-1653.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

B. Berryman, General Manager
D. Bice, Licensing Manager (Acting)
T. Boozer, Project Manager
B. Byford, Superintendent Operations Requalification Training
S. Cotton, Training Manager
R. Gordon, Manager of Projects
D. James, Nuclear Safety Assurance Director
J. McCoy, Programs and Components Manager
T. Mitchell, Site Vice President
D. Moore, Radiation Protection Manager
C. Reasoner, Engineering Director
T. Tullos, Superintendent Nuclear Industrial Safety and Human Performance
F. Van Buskirk, Licensing Specialist
R. Walters, Operations Manager
P. Williams, Design Engineering Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

05000313/2009002-01	NCV	Inadequate Procedure for Reactor Protection System Maintenance (Section 1R22)
05000313/2009002-02	FIN	Inadequate Service Air Compressor Torque Value Led to Loss of Control Rod Drive Cooling and Manual Reactor Trip (Section 4OA3.2)
05000313/2009002-03	NCV	Failure to Provide Complete and Accurate Information to the NRC Following a Plant Trip (Section 4OA3.3(a))
05000313/2009002-04	FIN	Failure to Follow Procedure for Use of a Torque Amplifying Device on a Valve in the Generator Hydrogen System (Section 4OA3.3(b))
05000368/2009002-05	FIN	Failure to Follow Procedure for Flow Accelerated Corrosion Program (Section 4OA3.4)

Closed

05000368/2008001-00	LER	Containment Isolation Valve Inoperable Longer than Allowed by Technical Specifications as a Result of Personnel Error During Planning and Construction of Scaffolding (Section 4OA3.6)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

PROCEDURES

NUMBER	TITLE	REVISION
OP-2106.032	Unit 2 Freeze Protection Guide	16
OP-1104.039	Plant Heating and Cold Weather Operations	20

MISCELLANEOUS

NUMBER	TITLE	REVISION
	Unit 2 Electronic Temporary Modification Database	
	Unit 1 and Unit 2 Operations Logsheets	
ER-ANO-2002-0006	Operation of ABHV Supply Fans with Plenum Doors Open	0
ER-ANO-2002-0145-002	Utilize Current Production Portable Heater	0
ER-ANO-2002-0145-001	Justification for Use of Portable Heaters in AAC Generator Building	0

CONDITION REPORTS

ANO-2-2001-1320	ANO-2-2008-2367	ANO-C-1997-0165	ANO-C-2008-1379

Section 1R04: Equipment Alignment

CALCULATIONS

NUMBER	TITLE	REVISION
Calc-92-R-0024-01	Flooding Evaluation INPO SOER 85-5	0
Calc-92-R-0034-01	Flooding Evaluation INPO SOER 85-5 2nd Iteration	0

NUMBER	TITLE	REVISION
OP-1106.006	Emergency Feedwater Pump Operation	76

DRAWING

NUMBER	TITLE	REVISION
M-217, Sheet 2	Emergency Diesel Generators, K4-A	27

Section 1RO5: Fire Protection

NUMBER	TITLE	REVISION
FHA	Arkansas Nuclear One Fire Hazards Analysis	11
PFP-U1	ANO Prefire Plan (Unit 1)	9
PFP-U2	ANO Prefire Plan (Unit 2)	9
OP-1000.152	Unit 1 & 2 Fire Protection System Specifications	7
EN-DC-127	Control of Hot Work and Ignition Sources	5
FHA	Arkansas Nuclear One Fire Hazards Analysis	11

CALCULATIONS

NUMBER	TITLE	REVISION
CALC-85-E-0053-031	Fire Area EE Combustible Loading Calculation	

DRAWING

NUMBER	TITLE	REVISION
FZ-2038, Sheet 1	No title for this document	2

Section 1R12: Maintenance Effectiveness

PROCEDURE

NUMBER	TITLE	REVISION
OP-1104.024	Instrument Air System	33

CONDITION REPORTS

ANO-C-2008-2266	ANO-1-2007-2325	ANO-1-2007-0971	ANO-1-2008-0330
ANO-C-2009-0214	ANO-1-2007-0506	ANO-1-2007-1506	ANO-1-2008-0332
ANO-1-2007-0043	ANO-1-2007-1642	ANO-1-2008-0938	ANO-1-2008-2188

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION
STM 1-48	Compressed Air Systems	11
ULD-1-SYS-11	ANO Unit 1 Instrument Air	4
	Maintenance Rule Database Performance Criteria Basis, Unit 1 Instrument Air	

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

NUMBER	TITLE	REVISION
COPD-024	Risk Assessment Guidelines	21

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	DATE
Plant Risk assessment		March 4, 2009

Section 1R15: Operability Evaluations

PROCEDURE

NUMBER	TITLE	REVISION
OP-1307.009	Unit 1 Pressurizer Heater Checkout	09-04-0

CONDITION REPORTS

ANO-1-2008-2218	ANO-1-2008-2210	ANO-1-2009-0158	ANO-C-2009-0278

Section 1R18: Plant Modifications

PROCEDURES

NUMBER	TITLE	REVISION
COPD-024	Risk Assessment Guidelines	21
EN-DC-141	Design Inputs	5

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION
EC-11074	Disable Chiller Lockout	

Section 1R19: Postmaintenance Testing

PROCEDURES

NUMBER	TITLE	REVISION
OP-1304.063	Unit 1 P-7A Speed Control Calibration	17
OP-1104.027	Battery and Switchgear Emergency Cooling System	32
OP-2106.006	Emergency Feedwater System Operations	71

OP-2107.001	Electrical Systems Operations	70
OP-1104.003	Chemical Addition	43
OP-1104.004	Decay Heat Removal Operating Procedure	81
OP-1106.006	Emergency Feedwater Pump Operation	76

CONDITION REPORTS

ANO-1-2008-2374	ANO-1-2009-0327	ANO-2-2009-0375	ANO-2-2009-0465
ANO-1-2008-2646	ANO-1-2009-0579		

DRAWING

NUMBER	TITLE	REVISION
E-2215	Schematic Diagram Containment Spray Pump 2P35B	22

WORK ORDERS

00163593	51511884	51674504	51681739
00183225	51674501	51674505	51685140
00184336			

Section 1R22: Surveillance Testing

PROCEDURES

NUMBER	TITLE	REVISION
OP-2106.006	Emergency Feedwater System Operations	70
OP-2104.036	Emergency Diesel Generator Operations	63
OP-1106.006	Emergency Feedwater Pump Operation	76
OP-1304.063	Unit 1 P-7A Speed Control Calibration	17
OP-2304.037	Unit 2 Plant Protection System Channel A Test	43

CONDITION REPORTS

ANO-1-2009-0058	ANO-1-2009-0066	ANO-C-2009-0404

WORK ORDERS

00177206	00178928	51546380	51677666

SECTION 1EP6: Drill Evaluation

MISCELLANEOUS

NUMBER	TITLE	REVISION
SES-2-011	Unit 2 Dynamic Exam Scenario	10
	Drill Exercise and Actual Event Performance--Attachment 3	

Section 4OA2: Identification and Resolution of Problems

PROCEDURES

NUMBER	TITLE	REVISION
OP-2106.006	Emergency Feedwater System Operations	70
EN-LI-102	Corrective Action Process	12
EN-DC-203	Maintenance Rule Program	1
EN-DC-204	Maintenance Rule Scope and Basis	1
EN-DC-205	Maintenance Rule Monitoring	2
EN-DC-206	Maintenance Rule (a)(1) Process	1

CONDITION REPORTS

ANO-2-2008-0231	ANO-2-2008-2099	ANO-C-2008-0251	ANO-C-2008-1114
ANO-2-2008-0299	ANO-C-2007-1346	ANO-C-2008-0313	ANO-C-2008-1717
ANO-2-2008-1265	ANO-C-2007-1361	ANO-C-2008-1084	

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION
ULD-0-SYS-19	ANO 1 Alternate AC Generation System	1
	Maintenance Rule Database Performance Criteria Basis, Unit 2 Alternate AC	

Section 4OA3: Event Follow-Up

PROCEDURE

NUMBER	TITLE	REVISION
EN-DC-315	Flow Accelerated Corrosion Program	0

CONDITION REPORTS

ANO-1-2008-2754	ANO-1-2009-0281	ANO-1-2009-0260	ANO-2-2009-0319

Section 4OA5: Other Activities (TI-172)

WELD DOCUMENTS

NUMBER	TITLE	REVISION
CEP-NDE-0496	Manual UT of Dissimilar Metal Welds	3
PDI-UT-10	PDI Qualifications for ASME Appendix VIII	B
WPS 08-043-T-001	Bridge Layer for Decay Heat Nozzle WOL	1
WPS 08-08-T-001	Butter Stainless Steel Layer for Decay Heat Nozzle WOL	2
WPS 01-08-T-804	Weld Overlay Layers for Decay Heat Nozzle WOL	5
QAP 8.0	Control and Issue of Weld Filler Ma terial	11
QAP 8.1	Material Receiving and Control Procedure	7
QAP 9.1	Workmanship and Visual Inspection Criteria for ASME Welding	14
QAP 9.3	Liquid Penetrant Inspection Procedure	18
QAP 9.6	High-Temperature Liquid Penetrant Inspection Procedure, Using Color visible/Solvent Removable Penetrant Technique	11
QAP 9.16	Liquid Penetrant Inspection Procedure Solvent Removable Visible Dye for Alloy 600 Weld Overlay	4
QAP 9.21	Welding Procedure and Performance	2
QA 12.0	Control of Measuring and Test Equipment	13
SEP-A600-001	Alloy 600 Management Program	0
OP-2311.009	ANO Unit 1 and Unit 2 Alloy 600 Inspections	0
105294-TR-027	WSI Traveler Nozzle Onlay Repair Core Flood Nozzle	0
10524-TR-006	Nozzle WOL Repair for Decay Heat Nozzle	0
10524-01	Weld Material Certificates of Compliance	
PQR’s	Various Personnel Qualification Records	0

NONDESTRUCTIVE EXAMINATION PACKAGES

WELD NUMBERS	TITLE	REVISION
DH-ANO-001	Ultrasonic Examination for Decay Heat Nozzle	0
SI-21-064	Ultrasonic Examination for High Pressure Injection/Makeup Dual Function Nozzle	0

DRAWINGS

NUMBER	TITLE	REVISION
ANO-52Q-01	Hot Leg Decay Heat Nozzle Weld Overlay Design	1
404517	Decay Heat Nozzle ANO Unit 1 Construction Drawing	1
ANO-52Q-02	RPV Core Flood Nozzle Weld Onlay Design	2

Note: Drawings that are not included in work order packages are included here

CALCULATIONS

NUMBER	TITLE	REVISION
CALC-ANO1-ME-07-00005	Operability Assessment of ANO-1 EOTSGs	0

CONDITION REPORTS

ANO-1-2007-00695	ANO-1-2007-01036	ANO-1-2008-00249	ANO-1-2008-01976
ANO-1-2007-00708	ANO-1-2007-01112	ANO-1-2008-00929	ANO-1-2008-02061
ANO-1-2007-00770	ANO-1-2007-01273	ANO-1-2008-01099	ANO-1-2008-02119
ANO-1-2007-00799	ANO-1-2007-01878	ANO-1-2008-01350	ANO-1-2008-02181
ANO-1-2007-00959	ANO-1-2007-02286	ANO-1-2008-01545	
ANO-1-2007-01030	ANO-1-2007-02286	ANO-1-2008-01546	

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION / DATE
ANO-ECR-5795	Steam Generator Pre-Outage Degradation Assessment and Repair Criteria for 1RF21	0
EC-3742	Cycle 21 Steam Generator Operational Assessment Report	1
Areva 51-9061913	Root Cause Analysis for Tie Rod Bowing in ANO Unit 1 EOTSG's	0

IR-2006-115	EPRI review of Arkansas Nuclear One Unit 1 Dissimilar Metal Weld Walk-down Information	1
EPRI Document	Core Flood Onlay Test Mockup Equivalency Testing Results	September 2, 2008
EPRI Document	Summary of Wesdyne International, LLC 10 Depth Sizing Results Obtained from the Inside Surface	August 13, 2008
EPRI Document	Nondestructive Evaluation: Ultrasonic Equivalency Testing of Weld Inlay Components, Technical Update	April 2008
WSI-MW-CRIL-001	Evaluation of Cr Content on First Layer of Weld Overlays for Top and Bottom Nozzles of Pressurizer	0
EC-607	Core Flood Nozzle Dissimilar Metal Butt Weld Alloy 82 and 182 Weld Metal Mitigation	0
R&RP No. 08-2080	Weld Repair/Replacement Package Request, "Core Flood Nozzle to Safe End Weld	0
Eval. 06-1-0717	Boric Acid Evaluation CV-1228	February 1, 2006
Eval. 07-1-0804	Boric Acid Evaluation CV-1228	March 27, 2007
Eval. 06-1-0709	Boric Acid Evaluation CV-1228	February 22, 2006
Eval. 05-1-0543	Boric Acid Evaluation CV-1228	April 11, 2005
Eval. 05-1-0542	Boric Acid Evaluation P-35A	March 26, 2005
R&RP No. 08-2079	Weld Repair/Replacement Package Request, "Core Flood Nozzle to Safe End Weld	0
ECN 9613	Core Flood Nozzle Dissimilar Metal Butt Weld Alloy 82 and 182 Mitigation	0
PQR-01-08-T-700	Core Flood Nozzle Weld Onlay	1
Technical Justification	Technical Justification for Core Flood Nozzle Weld Onlay Ultrasonic Testing	1