UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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February 10, 2005

Jeffrey S. Forbes, Vice President,
Operations
Arkansas Nuclear One
Entergy Operations, Inc.
1448 S.R. 333
Russellville, Arkansas 72801-0967

SUBJECT: ARKANSAS NUCLEAR ONE - NRC INTEGRATED INSPECTION REPORT 05000313/2004005 AND 05000368/2004005

Dear Mr. Forbes:

On December 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Arkansas Nuclear One, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings, which were discussed on January 6, 2004, with you and other members of your staff.

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

This report documents two apparent violations regarding the failure to correctly wire the motor for the Unit 2 Containment Fan Cooler 2VSF-1B which rendered the fan cooler inoperable for approximately 11 months and the failure to adequately test the fan cooler following maintenance. These findings have potential safety significance greater than very low significance. These findings do not represent a current safety concern since the maintenance error was detected and corrected on September 29, 2004.

In addition, this report documents two NRC identified and three self-revealing findings of very low safety significance (Green). All of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these seven findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest these 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 DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at Arkansas Nuclear One, Units 1 and 2, facility.

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

Sincerely,

/RA/

Scott Schwind, Chief
Project Branch D
Division of Reactor Projects

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

Enclosure:
NRC Inspection Report 05000313/2004005 and 05000368/2004005
w/Attachments: Supplemental Information; Failure to Identify Non Conforming Containment Spray Pump Breaker Phase 3 Analysis

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SISP Review Completed: __SCS_ ADAMS: **/** Yes **G** No Initials: __SCS_
/ Publicly Available **G** Non-Publicly Available **G** Sensitive **/** Non-Sensitive

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RIV:RI:DRP/D	RI:DRP/D	SRI:DRP/D	C:DRP/D	C:DRS/OB
JLDixon	ELCrowe	RWDeese	SCSchwind	ATGody
SCS for	**SCS for**	**SCS for**	**/RA/**	**/RA/**
2/10/05	2/10/05	2/10/05	2/2/05	2/4/05
C:DRS/PSB	D:DRS/PEB	DRS/SRA	C:DRS/EB	C:DRP/D
MPShannon	LJSmith	DPLoveless	JAClark	SCSchwind
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2/4/05	2/3/05	2/4/05	2/7/05	2/10/05

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Enclosure

Dockets:	50-313, 50-368
Licenses:	DPR-51, NPF-6
Report:	05000313/2004005 and 05000368/2004005
Licensee:	Entergy Operations, Inc.
Facility:	Arkansas Nuclear One, Units 1 and 2
Location:	Junction of Hwy. 64W and Hwy. 333 South Russellville, Arkansas
Dates:	September 24 through December 31, 2004
Inspectors:	L. Carson II, Senior Health Physicist D. Carter, Health Physicist E. Crowe, Resident Inspector R. Deese, Senior Resident Inspector J. Dixon, Resident Inspector J. Drake, Operations Engineer R. Lantz, Senior Emergency Preparedness Inspector N. Taylor, Project Engineer
Approved By:	Scott Schwind, Chief, Project Branch D Division of Reactor Projects
Attachment 1:	Supplemental Information
Attachment 2:	Failure to Identify Non Conforming Containment Spray Pump Breaker Phase 3 Analysis

CONTENTS

SUMMARY OF FINDINGS

IR 05000313/2004005, 05000368/2004005; 9/24/04 - 12/31/04; Arkansas Nuclear One, Units 1 and 2; Maintenance Effectiveness, Operator Performance During Nonroutine Plant Evolutions and Events, Postmaintenance Testing, Event Followup, and Other Activities.

This report covered a 3-month period of inspection by resident and regional specialist inspectors. Seven Green noncited violations were identified. 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's review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing noncited violation of Unit 1 Technical Specification 5.4.1, “Procedures,” was reviewed for an inadequate procedure related to the recovery from a control rod asymmetric fault. Station Procedure OP 1203.003, “Control Rod Drive Malfunction Action,” contained no steps for resetting faults utilizing the fault reset switch and, in absence of appropriate guidance, operators took action which allowed outward automatic rod motion which resulted in an unplanned reactor power increase to 101.9 percent. This issue involved human performance crosscutting aspects associated with control room personnel taking non-urgent, non-proceduralized actions without involving management. This issue also involved problem identification and resolution crosscutting aspects associated with the operations staff failing to generate procedural guidance following two previous similar occurrences. Procedural improvements and other corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program as Condition Report ANO-1-2004-2428.

  This finding is more than minor because it is analogous to Example 4.b in Appendix E, “Examples of Minor Issues,” to Manual Chapter 0612, “Power Reactor Inspection Reports,” because a significant procedural error caused an unplanned reactor power transient. Using the Phase 1 worksheets in Manual Chapter 0609, “Significant Determination Process,” the finding was determined to have very low safety significance (Green) because this transient initiator does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available.(Section 1R14).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation of 10 CFR 50.65(a)(2) for failure to establish adequate measures to demonstrate that the performance of the Unit 2 pressurizer proportional heaters was effectively monitored in the maintenance rule program. Failures of the heater breakers were not being monitored as part of the reactor coolant system or the 480 volt electrical system in the licensee's maintenance rule program. The inspectors identified human performance cross-cutting aspects associated with engineers not identifying events that should have been entered in the maintenance rule database.

The inspectors determined that this finding is greater than minor because it is analogous to Example 1.i of Appendix E, "Examples of Minor Issues," of Manual Chapter 0612, "Power Reactor Inspection Reports," because the licensee's equipment performance problems were such that an (a)(2) demonstration could not be justified. Using the Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," the issue was determined to have very low safety significance because it did not screen as risk significant due to external initiating events and because the safety function of the pressurizer heaters was always maintained (Section 1R12).

- Green. A self-revealing noncited violation of 10 CFR 50.65(b)(2) was identified when the licensee failed to include the Unit 2 startup and blowdown demineralizer pressure relief valves in their maintenance rule program. These valves are nonsafety-related however, their failure could prevent the safety-related emergency feedwater system from performing its function during accidents occurring during plant startups and shutdowns. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program as Condition Report ANO-2-2004-1743.

  The inspectors determined that the finding is more than minor because, if left uncorrected, the finding would become a more significant safety concern since failure of these valves could result in an over pressure condition on the emergency feedwater pumps common suction piping. Using the Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," the inspectors considered this finding to have very low safety significance because there was no loss of safety function for the emergency feedwater pumps and it did not screen as risk significant due to external initiating events (Section 1R12).

- TBD. Two examples of a self-revealing apparent violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," occurred when postmaintenance testing for Unit 2 Containment Cooler Fan 2VSF-1B and Flow Switch 2FS-8207-1B was not performed after maintenance on these components. This resulted in the failure to detect the fact that these components were inoperable. This issue involved human performance crosscutting aspects associated with electrical maintenance personnel improperly wiring the containment cooling fan and outage management improperly deferring fan flow switch maintenance from the outage. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program as Condition Report ANO-2-2004-0688.

This finding is being considered an apparent violation pending completion of its significance determination. The examples of this finding are more than minor because they are analogous to Example 5.b of Appendix E, “Examples of Minor Issues,” of Manual Chapter 0612, “Power Reactor Inspection Reports,” because Containment Cooling Fan 2VSF-1B and Flow Switch 2FS-8207-1B were returned to service in inoperable conditions. The finding was determined to potentially have greater than very low safety significance. However, Manual Chapter 0609, Attachment 1, "Significance and Enforcement Review Process," requires further review by a senior reactor analyst. This review had not been conducted by the end of this inspection period (Section 1R19).

- TBD. A self-revealing noncited violation of Unit 2 Technical Specification 3.6.2.3, “Containment Cooling System,” occurred since the Unit 2 Containment Cooler 2VSF-1B was inoperable in excess of its specified allowed outage time. The containment cooler was out of service for over 11 months before the licensee discovered that the fan motor had been improperly wired. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program as Condition Report ANO-1-2004-1688. This issue involved problem identification and resolution crosscutting aspects associated with engineers not adequately questioning indications of abnormal containment cooling system operation and performing poor operability evaluations.

  This finding is being considered an apparent violation pending completion of its significance determination. This finding is more than minor because it affected the mitigating systems cornerstone objective of ensuring the availability and reliability of a system that responds to initiating events to prevent undesirable consequences. Based on the results of a Significance Determination Process, Phase 2 analysis, the finding was determined to potentially have greater than very low safety significance. However, Manual Chapter 0609, Attachment 1, "Significance and Enforcement Review Process," requires further review by a senior reactor analyst. This review had not been conducted by the end of this inspection period (Section 1R19).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XV, “Nonconforming Materials, Parts, or Components,” for the failure to establish controls to prevent a circuit breaker with a loose connection from being installed in Unit 2. A loose connection in the Containment Spray Pump 2P-35A breaker was not identified prior to installation in the plant even though there were several undocumented instances where similar loose connections were discovered during receipt inspections of other breakers in its group. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program as Condition Report ANO-2-2004-1712.

The finding is more than minor because it affected the mitigating systems cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences. Using Appendix A, "Technical Basis For At Power Significance Determination Process," of Manual Chapter 0609, "Significance Determination Process," and the Phase 2 worksheets from "Risk-informed Inspection Notebook for Arkansas Nuclear One - Unit 2," the finding was determined to potentially have greater than very low safety significance because the loose connection could have resulted in an actual loss of the safety function of the Unit 2 Train A containment spray pump during a small break loss of coolant accident or stuck open relief valve events. Further examination in a Phase 3 analysis by regional senior risk analysts demonstrated that this finding is of very low safety significance because the fault was intermittent and, even if the pump would not have started, it could have been easily started locally at the breaker (Section 4OA5).

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for the failure to take timely corrective action to repair an oil leak on a temperature switch for the Unit 1 Emergency Diesel Generator K-4B in May 2004. This failure resulted in the oil leak progressively worsening and ultimately developing into a leak which challenged the emergency diesel generator safety function. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program as CR ANO-1-2004-1705.

  The finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of equipment availability and reliability. Therefore, the finding is greater then minor. Using the Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," the inspectors determined that the finding was of very low safety significance since the condition that would have rendered the EDG inoperable only existed for five days which was less than the allowed outage time in the Technical Specifications. In addition, this finding did not screen as risk significant due to external initiating events (Section 4OA5).

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 its corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent rated thermal power and remained there until October 2, 2004, when operators reduced reactor power to 96 percent rated thermal power due to oscillations of the integrated control system. Following repairs to the integrated control system on October 3, 2004, the unit was returned to 100 percent rated thermal power and remained there until December 3, 2004, when operators reduced reactor power to approximately 40 percent rated thermal power for repairs to Main Feedwater Pump P-1A. On December 4, 2004, the operators returned the unit to 100 percent rated thermal power, where it remained throughout the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent rated thermal power and remained there until September 27, 2004, when operators shutdown the unit to allow repairs to a feedwater pipe. Following repairs, the reactor was returned to 100 percent rated thermal power on October 3, 2004, and remained there throughout the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment (71111.04)

1. Partial System Walkdowns

a. Inspection Scope

The inspectors (1) walked down portions of the two below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned and (2) compared deficiencies identified during the walk down to the corrective action program (CAP) to ensure problems were being identified and corrected.

C October 26, 2004, Unit 1 service water system: the inspectors performed a partial system walkdown of accessible portions of the green train during replacement of Service Water Pump P-4A water column.

• November 30, 2004, Unit 2 service water system: the inspectors performed a partial system walkdown of accessible portions of the green and red trains during replacement of Service Water Pump 2P-4B water column

The inspectors completed two samples.

b. Findings

No findings of significance were identified

1R05 Fire Protection (71111.05)

a. Inspection Scope

Routine Inspection

The inspectors walked down the six below listed plant areas to assess the material condition of active and passive fire protection features, their operational lineup, and their operational effectiveness. The inspectors (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the CAP to determine if the licensee identified and corrected fire protection problems.

C November 1, 2004, Unit 2 electrical equipment room, Fire Zone 2076-HH

• November 23, 2004, Units 1 and 2 Area L which includes diesel fuel storage vault corridor and the diesel fuel storage vaults

• December 1, 2004, Unit 2 high pressure safety injection (HPSI) and low pressure safety injection (LPSI) Train A pump room, Fire Zone 2014-L

• December 1, 2004, Unit 2 HPSI and LPSI Train B Pump Room, Fire Zone 2007-LL

• December 10, 2004, Unit 2 electrical equipment (2B9/2B10) room, Fire Zone 2108-S

• December 10, 2004, Unit 2 core protection calculator (CPC) room (new CPC room), Fire Zone 2098-G

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

Annual External Flood Protection Inspection

The inspectors (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving external flooding; (2) reviewed the CAP to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the below listed areas to verify the adequacy of (a) equipment seals located below the flood line, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits; and (f) temporary or removable flood barriers.

C December 14-16, 2004, Unit 1 auxiliary building

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved different sizes of loss of coolant accidents in order to recognize reactor building sump blockage indications and possible corrective actions.

- Unit 1 simulator, November 12, 2004, Training Cycle 1-05-02, A1SPGLOR050203, “Reactor Building (RB) Sump Blockage Issue”

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the three below listed maintenance activities to (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the Maintenance Rule, 10 CFR Part 50, Appendix B, and Technical Specifications.

- August 3, 2004, Unit 1 480 VAC safety-related molded case circuit breaker over current testing

- September 29-30, 2004, Unit 2 pressurizer proportional heater breakers surveillance testing

- September 30, 2004, Unit 2 start up and blowdown demineralizer system pressure relief valve testing

The inspectors completed three samples.

b. Findings

1. Unit 2 Pressurizer Proportional Heater Breakers

Introduction. The inspectors identified a Green noncited violation (NCV) of 10 CFR 50.65(a)(2) for failure to establish adequate measures to demonstrate that the performance of the Unit 2 pressurizer proportional heaters was effectively monitored in the maintenance rule program.

Description. During a Unit 2 containment walkdown on September 30, 2004, in preparation for a reactor startup, the licensee found Breakers 1 and 3 tripped free on pressurizer proportional heater power Panel 2PP6. The licensee closed both breakers and continued on with startup preparations without determining the cause of the breaker trips or assessing operability of the proportional heaters. The licensee later discovered, through performance of the pressurizer heater surveillance test, that one pressurizer proportional heater train was inoperable because it could not provide the 150 kilowatts of heat required by Technical Specifications. While reviewing the history of the breakers, the inspectors discovered that a similar situation occurred on February 7, 2004, when the licensee was performing a containment closeout checklist prior to entering Mode 3. Breaker 1 on Power Panel 2PP6 was found in the tripped free condition. The licensee closed the breaker and continued with startup preparations without determining the cause.

The inspectors reviewed the licensee’s maintenance rule database to ensure these failures were adequately addressed. The pressurizer proportional heaters were scoped in maintenance rule program under the reactor coolant system to provide for reactor coolant system pressure control. Upon discussion with the system engineer for the reactor coolant system, the inspectors determined that the heater breaker failures were not being monitored as part of the reactor coolant system because the engineer assumed they were included in the 480 volt electrical system. Upon questioning the system engineer for the 480 volt electrical system, the inspectors determined that the only items being monitored were items that could cause an entire 480 volt bus to fail, not individual breakers. The 480 volt electrical system engineer had assumed that breakers related to specific systems were handled under their respective systems. As a result, the pressurizer proportional heater breaker failures were not being monitored in the maintenance rule program.

Analysis. The failure to implement the requirements of 10 CFR 50.65 was considered to be a performance deficiency. This finding affected the Mitigating Systems cornerstone and was more than minor because it is analogous to Example 1.i of Appendix E, "Examples of Minor Issues," of Manual Chapter 0612, "Power Reactor Inspection Reports," because the licensee's equipment performance problems were such that an (a)(2) demonstration could not be justified. Using the Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," the issue was determined to have very low safety significance because it did not represent an actual loss of safety function since the required amount of heaters were available and it did not screen as risk significant due to external initiating events. The inspectors identified a human performance crosscutting aspect associated with inattention to detail by system engineers during maintenance rule database reviews. The system engineers were not ensuring failures were being coded for appropriate reviews in the maintenance rule and engineering supervisors were not performing timely reviews of these classifications.

Enforcement. 10 CFR 50.65(a)(1), requires, in part, that the holders of an operating license shall monitor the performance or condition of structures, systems, or components within the scope of the rule as defined by 10 CFR 50.65(b), against licensee-established goals, in a manner, sufficient to provide reasonable assurance that such SSCs, are capable of fulfilling their intended functions.

10 CFR 50.65(a)(2) states, in part, that monitoring as specified in 10 CFR 50.65(a)(1) is not required where it has been demonstrated that the performance or condition of a structure, system, or component, is being effectively controlled through the performance of appropriate preventative maintenance, such that the structure, system, or component remains capable of performing its intended function.

Contrary to the above, the licensee failed to establish adequate measures to demonstrate the performance or condition of the Unit 2 pressurizer proportional heater breakers. Specifically, the breakers themselves were not being tracked against performance criteria to address the capability of the heaters to provide heat input to the reactor coolant system. The pressurizer proportional heaters were being tracked at a level to determine heater element failures, or bus power supply failures, but not breaker failures. Consequently, allowing the breakers to reach a state of repetitive failures without taking appropriate corrective actions would not demonstrate that preventative maintenance was effective to control the system's performance or condition to maintain its intended function. Because of the very low safety significance of the finding and because the licensee has entered this issue into their CAP as CR ANO-C-2004-2208, the inspectors treated this as a NCV violation, consistent with Section VI.A of the NRC Enforcement Policy, NCV 05000368/2004005-01, "Failure to Establish Adequate Measures to Demonstrate the Performance or Condition of the Unit 2 Pressurizer Proportional Heaters."

2. <u>Unit 2 Start Up and Blowdown Demineralizer Pressure Relief Valves</u>

<u>Introduction</u>. The inspectors reviewed a self-revealing Green NCV of 10 CFR 50.65(b)(2) for failure to include the Unit 2 startup and blowdown demineralizer pressure relief valves in the maintenance rule program.

<u>Description</u>. On September 27, 2004, during a normal plant shutdown of Unit 2 the licensee secured main feed pumps and lined up auxiliary feedwater to the steam generators. This was done by aligning the start up blowdown demineralizer to the emergency feedwater pumps' suction. The suction source of water to auxiliary and emergency feedwater was the condensate pump discharge through the start up demineralizer. While in this lineup on September 30 the start up blowdown demineralizer outlet pressure control Valve 2PCV-4542 failed closed with the plant at normal operating pressure and temperature. This pressure control valve is designed to maintain approximately 50 psig on its inlet side. System pressure increased rapidly to approximately 146 psig when the valve failed closed resulting in the emergency feedwater pump suction relief Valve 2PSV-0706 and the start up and blowdown demineralizer pressure relief Valves 2PSV-4594 A and B lifting to keep emergency feedwater suction piping below the design pressure of 150 psig. The nominal setpoint of all three relief valves is 150 psig. Had the setpoint for Valves 2PSV-4594 A and B been high, the design pressure for emergency feedwater suction piping could have been rapidly exceeded, resulting in a rupture of the common suction line and possibly rendering the emergency feedwater system inoperable. Depending upon the location of the rupture, emergency feedwater may not have been able to function using service water as a suction source. The licensee did not have relief Valves 2PSV-4595A or 2PSV-4594B in their preventative maintenance program, so there was no assurance that the valves would lift at the required pressure of 150 psig.

Since these relief valves were nonsafety-related components which could affect the operation of a safety-related system, the inspectors questioned licensee engineers how these failures were addressed by the maintenance rule program. The licensee engineers informed the inspectors that neither of these relief valves nor their functions were scoped in their maintenance rule program. Based on this, the inspectors concluded that the licensee had not adequately scoped these valves in their maintenance rule program.

<u>Analysis</u>. The failure to implement the requirements of 10 CFR 50.65 was considered to be a performance deficiency. This finding affected the Mitigating Systems cornerstone and was more than minor because, if left uncorrected, the finding would

become a more significant safety concern by potentially causing an over pressure condition on the emergency feedwater pumps common suction piping. Using the Phase 1 worksheets in Manual Chapter 0609, “Significance Determination Process,” the inspectors consider this finding to have very low safety significance because there was no loss of safety function for the emergency feedwater pumps and it did not screen as risk significant due to external initiating events.

Enforcement. 10 CFR 50.65(b)(2) requires, in part, that the scope of the monitoring program specified in paragraph (a)(1) include nonsafety-related SSCs whose failure can prevent safety-related SSCs from fulfilling their safety-related function. Contrary to the above, the nonsafety-related start up and blowdown demineralizer pressure relief Valves 2PSV-4594 A and B were not included in the scope of the monitoring program specified in 10 CFR 50.65(a)(1). The inclusion of the start up and blowdown demineralizer pressure relief valves in the scope of the monitoring program is necessary because the failure of that system could prevent the emergency feedwater system, a safety-related system, from fulfilling its safety-related function. Because of the very low safety significance and because the licensee included this condition in their CAP as CR ANO-2-2004-1743, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000368/2004005-02, “Failure to Include Nonsafety Related Components that Affect Safety-Related Functions into the Maintenance Rule Program.”

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

a. Inspection Scope

Risk Assessment and Management of Risk

The inspectors reviewed the below listed assessment activities to verify (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- November 1-4, 2004, Unit 1 Service Water Pump P-4A wet end replacement and testing
- November 12, 2004, Unit 2 service water and emergency diesel generator (EDG)
- November 28 through December 4, 2004, Unit 1 various components from emergency feedwater, EDG, down power for main feedwater power supply, and turbine governor valve trip testing

The inspectors completed three samples.

Emergent Work Control

The inspectors (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; (3) reviewed the CAP to determine if the licensee identified and corrected risk assessment and emergent work control problems.

- September 27 through October 2, 2004, Unit 2, main feedwater leak forced outage

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Nonroutine Plant Evolutions and Events (71111.14, 71153)

a. Inspection Scope

The inspectors (1) reviewed operator logs, plant computer data, and/or strip charts for the below listed evolutions to evaluate operator performance in coping with nonroutine events and transients, (2) verified that the operator response was in accordance with the response required by plant procedures and training, and (3) verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the nonroutine evolutions sampled.

- September 28, 2004, Unit 2 reactor shutdown and cooldown to effect repairs to a leak on a vent valve stack on the feedwater system

- November 28, 2004, Unit 1 plant overpower to approximately 101.9 percent during recovery from an asymmetric control rod alarm

- December 3, 2004, Unit 1 plant downpower to approximately 40 percent rated thermal power for repairs to “A” main feedwater Pump P-1A

The inspectors completed three samples.

b. Findings

Introduction. The inspectors identified a Green NCV of the Unit 1 Technical Specification 5.4.1, “Procedures,” for an inadequate procedure related to the recovery from a control rod asymmetric fault.

<u>Description</u>. On November 27, 2004, with Unit 1 operating at approximately 100 percent power, control room operators received Annunciator K08-C2, "Control Rod Asymmetric," and Annunciator K08-A2, "CRD Withdrawal Inhibited." Operators determined that Group 2, Rod 8 absolute position indication was providing an erroneous reading which caused the annunciator alarms. Station Procedure OP 1203.003, "Control Rod Drive Malfunction Action," Revision 20, provided guidance on bypassing the absolute position indication for a single rod. The operators performed this action which resulted in clearing the "Control Rod Asymmetric" annunciator alarm but not the "CRD Withdrawal Inhibited" annunciator alarm since the fault reset switch on the rod control panel had not been depressed. Station Procedure OP 1203.003 contained no steps for resetting the fault utilizing the fault reset switch on the rod control panel. Operators then referenced Station Procedure OP 1105.009, "CRD System Operating Procedure," Revision 18, for guidance; this procedure just described the purpose of the fault reset switch and provided no steps on resetting the fault under the current plant conditions. Prior to informing plant management about the lack of procedural guidance, operators reset the fault by depressing the fault reset switch which cleared the "CRD Withdrawal Inhibited" annunciator alarm and removed the fault condition from the rod control system. However, a difference in the integrated control system desired reactor coolant temperature and actual reactor coolant temperature provided a temperature error signal to the rod control system that resulted in automatic rod withdrawal and a momentary increase in reactor power to 101.9 percent. The reactor subsequently automatically returned to its normal 100 percent power level in a few seconds and stabilized there.

The inspectors learned that in November 2002 and January 2003 these same conditions had been received and in both cases had been cleared without adequate guidance and with no automatic rod motion. The inspectors noted that, despite the lack of procedural guidance, no changes were initiated on these instances to correct the procedures.

<u>Analysis</u>. The failure to provide adequate procedure guidance for a repetitive rod control fault was considered to be a performance deficiency. This finding affected the Initiating Events cornerstone and was more than minor because it is analogous to Example 4.b in Appendix E, "Examples of Minor Issues," of Manual Chapter 0612, "Power Reactor Inspection Reports," in that a significant procedural error caused an unplanned power transient. Using Manual Chapter 0609, "Significant Determination Process," the inspectors determined this finding to have very low safety significance (Green) because this transient initiator does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. This issue involved human performance crosscutting aspects associated with control room personnel taking non-urgent, non-proceduralized actions without involving management upon discovery that procedural guidance was not available for current plant conditions. This issue also involved PI&R crosscutting aspects in that the operations staff failed to generate a procedural change for missing procedural steps following similar occurrences in November 2002 and January 2003.

<u>Enforcement</u>. Unit 1 Technical Specification 5.4.1, "Procedures," requires that the licensee establish and implement written procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, which required procedures for

abnormal, off normal, or alarm conditions. Contrary to the above, before November 27, 2004, Procedure 12003.003, "Control Rod Drive Malfunction Action," the procedure for resetting fault conditions utilizing the fault reset switch on the rod control panel was inadequate. Because this procedure was inadequate, operators took inappropriate action to reset the fault condition which resulted in an unplanned transient where reactor power momentarily reached 101.9 percent. Because of the very low safety and because the licensee included this condition in their CAP as CR ANO-1-2004-2428, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000313/2004005-03, "Operator Action due to Inadequate Procedure Results in Momentary Increase in Reactor Power Above Rated Thermal Power."

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- CR-ANO-2-2004-1666 — September 26, 2004, Unit 2 main feed header steam leak
- CR-ANO-2-2004-1688 — September 29, 2004, Unit 2 containment cooling Fan 2VSF-B rotating backwards
- CR-ANO-2-2004-1937 — October 6, 2004, Unit 2 misplaced spent fuel assembly in the spent fuel pool
- CR-ANO-1-2004-2306 — October 28, 2004, Unit 1 main steam isolation valve closure against backlog for a postulated steam line break

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R16 Operability Work-Arounds (71111.16)

a. Inspection Scope

Cumulative Review of the Effects of Operator Workarounds

The inspectors reviewed the cumulative effects of operator work arounds for Units 1 and 2 to determine (1) the reliability, availability, and potential for misoperation of a system; (2) if multiple mitigating systems could be affected; (3) the ability of operators to respond in a correct and timely manner to plant transients and accidents; and (4) if the licensee has identified and implemented appropriate corrective actions associated with operator workarounds.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the six below listed postmaintenance test activities of risk significant systems or components. For each item, the inspectors (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly realigned, and deficiencies during testing were documented. The inspectors also reviewed the CAP to determine if the licensee identified and corrected problems related to postmaintenance testing.

- October 2, 2003, Unit 2 Containment Cooling Plenum Flow Switch 2FS-8207-1B modification
- October 3, 2003, Unit 2 Containment Cooling Fan 2VSF-1B containment penetration conductor over current protective device inspection and testing
- May 8, 2004, Unit 1 EDG Room Ventilation Fan VEF-28C breaker replacement
- September 30 through October 2, 2004, Unit 2 Pressurizer proportional heaters, 2PP5 and 2PP6 breaker replacements and bus bar connection modifications

- December 1, 2004, Unit 2 Service Water Supply Valve 2SV-1511-1 to Containment Coolers 2VCC-2A and 2VCC-2B

- December 7, 2004, Unit 2 Feedwater Vent Stacks 2FW-2002A and 2FW-2002B weld repair

The inspectors completed six samples.

b. Findings

Introduction. Two examples of an apparent violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” were identified for the failure to accomplish postmaintenance testing on Unit 2 Containment Cooling Fan 2VSF-B and Containment Cooling Flow Switch 2FS-8207-B.

Description. On September 29, 2004, the licensee discovered that Containment Cooling Fan 2VSF-1B was rotating backwards. The inspectors questioned licensee personnel and reviewed the licensee’s root cause as well as a list of maintenance activities conducted on the containment cooling fan and its attendant instrumentation. From this review, the inspectors determined that the licensee performed a containment penetration conductor over current protective device inspection and test on October 3, 2003, during the Unit 2 Refueling Outage 2R16. This required the breaker and electrical terminations for the fan motor to be removed. After completion of this maintenance, electrical maintenance personnel reinstalled the circuit breaker for the containment cooling fan with two of the three phase power leads reversed. This error was caused by the electrician wiring the leads in the standard configuration typical for electrical breakers at ANO, rather than per the unique arrangement on this breaker’s particular electrical wiring schematic. The inspectors determined that the licensee’s Procedures OP 2307.22, “Unit 2 Containment Penetration Conductor Over Current Protective Device Inspection,” did not have postmaintenance testing requirements to verify proper operation of the fan after this maintenance. Instead, the licensee relied upon the lifted lead process which consisted of an electrician and a second checker. The inspectors concluded that this was not an adequate postmaintenance test.

Also, related to the containment fan cooler, the inspectors questioned why the containment cooler’s instrumentation (e.g., the fan flow switch) did not alert operators that problems existed with operation of the containment cooler. The inspectors discovered that the switch had been modified per Engineering Request ER-ANO-2002-0884 in Refueling Outage 2R16 on October 2, 2003, and was scheduled for a postmaintenance test in Work Order 50264360. This test was initially delayed because a portion of the containment cooling system was tagged out, making the switch testing impossible. Subsequently, licensee personnel never added the delayed postmaintenance test to the outage postmaintenance test list. After that, records showed that postmaintenance testing was deferred by outage management on October 15, 2003, 1 day after Refueling Outage 2R16 had ended, and therefore, was never accomplished. The inspectors concluded that the postmaintenance test was not conducted as set forth in the prescribed work order.

This condition is no longer an immediate safety concern since the licensee corrected the improper wiring and successfully retested Containment Cooling Fan 2VSF-13 after the discovery on September 29, 2004.

Analysis. The failure to perform postmaintenance testing on safety related equipment was considered to be a performance deficiency. These findings affected the Mitigating Systems and Initiating Events Cornerstones and are more than minor because they are analogous to Example 5.b of Appendix E, “Examples of Minor Issues,” of Manual Chapter 0612, “Power Reactor Inspection Reports,” in that Containment Cooling Fan 2VSF-1B and Flow Switch 2FS-8207-1B were returned to service in inoperable conditions. The Phase 1 worksheets in Manual Chapter 0609, “Significance Determination Process,” were used to conclude that a Phase 2 analysis was required since two reactor safet cornerstones were affected. The Phase 2 analysis was performed using Appendix A, “Technical Basis For At Power Significance Determination Process,” of Manual Chapter 0609, “Significance Determination Process,” and the Phase 2 worksheets from “Risk-Informed Inspection Notebook for Arkansas Nuclear One - Unit 2.” The inspectors assumed that the duration of the inoperability of the containment fan cooler was 11 months and 25 days and that operations personnel would not be able to recover the containment cooler. Inspectors also assumed that all other containment coolers remained operable throughout the 11 month, 25 days exposure time. The dominant core damage sequences involved a loss of AC or DC busses, a failure of emergency feedwater, and a failure of containment spray recirculation. Specifically, the small break loss of coolant accident and stuck open relief valve sequences were most limiting. A review of the Phase 2 analysis and performance of a Phase 3 analysis by a regional senior reactor analyst is needed to determine the final safety significance of the finding. This issue involved human performance crosscutting aspects associated with (1) electrical maintenance personnel improperly wiring the containment cooling fan and (2) outage management improperly deferring fan flow switch maintenance from the outage.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires that activities affecting quality shall be prescribed by documented instructions of a type appropriate to the circumstances and shall be accomplished according to these instructions. Contrary to this, on October 3, 2003, Fan 2VSF-1B was wired incorrectly after performing its containment penetration conductor over current protective device inspection and testing and the procedure did not have postmaintenance testing requirements which would have been appropriate to the circumstances to ensure operability. Additionally, Fan Flow Switch 2FS-8701-1B was modified on October 2, 2003, but its postmaintenance was not accomplished in accordance with its prescribed instructions. Pending determination of the findings final safety significance, this violation is being treated as an apparent violation, consistent with Section VI.A of the NRC Enforcement Policy: AV 05000368/2004005-04, “Two Examples of Failure to Conduct Postmaintenance Testing Associated with a Containment Cooler Fan.”

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the following risk significant outage activity to verify defense in depth commensurate with the outage risk control plan and compliance with the Technical Specifications: (1) the risk control plan, (2) tagging/clearance activities, (3) electrical power, (4) decay heat removal, (5) heatup and cooldown activities, and (6) licensee identification and implementation of appropriate corrective actions associated with outage activities.

- September 27 through October 3, 2004, Unit 2 forced outage to repair a steam leak on the main feed header

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, procedure requirements, and Technical Specifications to ensure that the five below listed surveillance activities demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated Technical Specification operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator (PI) data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- September 23, 2004, Unit 1 Green Train Decay Heat Removal Pump P-34B for preventative and corrective maintenance followed by surveillance test (inservice test)

- October 27, 2004, Unit 1 local leak rate testing of gaseous radwaste reactor building ventilation header isolation Valve CV-4804

- November 30, 2004, Unit 2 containment personnel airlock local leak rate test

- December 14, 2004, Unit 2 reactor building sump level Monitor 2LT-5641-2 surveillance test (reactor coolant system leak detection equipment)

- December 16, 2004, Unit 2 Station Battery 2D11 performance discharge test

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, plant drawings, procedure requirements, and Technical Specifications to ensure that the one listed temporary modification was properly implemented. The inspectors (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with the modification documents; (3) ensured that the postinstallation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC's were supported by the test; (4) verified that the modifications were identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that licensee identified and implemented any needed corrective actions associated with temporary modifications.

- September 30, 2004, Unit 1, Hatch 492 from train bay to Unit 1 auxiliary building Elevation 335' and auxiliary building Hatch 483 from Elevation 335' to 317'.

The inspectors completed one sample.

b. Findings

No findings of significance was identified.

Cornerstone: Emergency Preparedness

1EP1 Exercise Evaluation (71114.01)

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the 2004 biennial emergency preparedness exercise to determine if the exercise would acceptably test major elements of the emergency plan. The scenario included a dropped control rod, which resulted in fuel cladding damage; a steam generator tube rupture; loss of the main condenser and component cooling water; and failure of a main steam safety valve to fully seat after lifting. These conditions resulted in an ongoing radioactive steam release to the environment. The licensee activated all of their emergency facilities to demonstrate their capability to implement the emergency plan.

The inspectors evaluated exercise performance by focusing on the risk-significant activities of classification, notification, protective action recommendations, and assessment of offsite dose consequences in the simulator control room and the following emergency response facilities:

- Technical Support Center
- Operations Support Center
- Emergency Operations Facility

The inspectors also assessed personnel recognition of abnormal plant conditions, the transfer of emergency responsibilities between facilities, communications, protection of emergency workers, emergency repair capabilities, and the overall implementation of the emergency plan to verify compliance with the requirements of 10 CFR 50.47(b), 10 CFR 50.54(q), and Appendix E to 10 CFR Part 50.

The inspectors attended the post-exercise critiques in each of the above emergency response facilities to evaluate the initial licensee self-assessment of exercise performance. The inspectors also attended the formal presentation of critique items to plant management.

The inspectors completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector reviewed the Arkansas Nuclear One Emergency Plan, Revision 30, submitted in August 2004. This revision consisted of several administrative changes to clarify the emergency plan, such as definitions of “route alerting” and “supplemental notification,” replacement of figures with detailed maps for environmental sampling points, and replacement of several specific references with generic references of who will perform certain specific functions. Several changes to offsite support organizations and clarification of responsibilities was also made including relocation of the Arkansas State Emergency Operations Facility (formerly the “Technical Operations Control Center”) from the National Guard Armory to the Entergy Operations, Inc., office in Russellville.

The revision was compared to the previous revisions, to the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the revisions decreased the effectiveness of the plan.

The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspector reviewed documents related to the CAP, to determine the licensee’s ability to identify and correct problems in accordance with the requirements of 10 CFR 50.47(b)(14) and 10 CFR Part 50, Appendix E. Documents reviewed during the inspection are listed in the attachment.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the below listed drills and simulator-based training evolutions contributing to drill/exercise performance and emergency response organization performance indicators, the inspectors (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action requirements development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance of the NEI 99-02 document’s acceptance criteria.

- November 17, 2004, Unit 1 simulator, Emergency Operations Facility, Technical Support Center. The inspectors observed a full scale emergency response organization drill. The scenario consisted of a dropped control rod, a steam generator tube rupture, a main steam safety valve sticks open, natural circulation, and reactor coolant system activity greater than 1 percent failed cladding.

- November 30, 2004, Unit 1 simulator. The inspectors observed Dynamic Exam Scenario ES-1-025, Revision 5. The scenario consisted of tripping a heater drain pump, a dropped control rod, multiple dropped control rods, a stuck open main steam safety valve, and a steam generator tube rupture.

The inspectors completed two samples consisting of one drill and one simulator based evolution.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

To review and assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and locked high radiation areas, the inspectors interviewed radiation workers and radiation protection personnel involved in high dose rate and high exposure jobs. The inspectors discussed changes to the access control program with the radiation protection manager. The inspectors also conducted plant walkdowns within the radiologically controlled area and conducted independent radiation surveys of selected work areas. The following items were reviewed and compared with regulatory requirements:

- Area postings and other access controls for airborne radioactivity areas, radiation areas, locked high radiation areas, and very high radiation areas
- Access controls, radiation work permits, and radiological surveys involving airborne radioactivity areas and high radiation areas
- Locked high radiation area key controls
- Internal dose assessment for exposures exceeding 50 mrem Committed Effective Dose Equivalent (No opportunities for review were identified.)
- Setting, use, and response of electronic personal dosimeter alarms
- Conduct of work by radiation protection technicians and radiation workers in areas with the potential for high radiation dose. (No opportunities were provided to observe radiological significant work during the inspection week.)
- Dosimetry placement when work involved a significant dose gradient

- Controls involved with the storage of highly radioactive items in the spent fuel pool
- Quality Assurance Surveillance Report QS-2003-ANO-031, “Access Controls to Radiologically Significant Areas”
- A summary of access controls and high radiation area work practice related to corrective action documents for CRs written since April 2002 and selected specific examples

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspector used the requirements in 10 CFR Part 20 and the licensee’s procedures required by Technical Specifications as criteria for determining compliance. The inspectors interviewed licensee personnel and reviewed:

- Site specific ALARA procedures
- Five work activities of highest exposure significance completed during the last outage
- Interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling, and engineering groups
- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding
- Workers use of the low dose waiting areas
- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

- Declared pregnant workers during the current assessment period, monitoring controls, and the exposure results

- Self-assessments and audits related to the ALARA program since the last inspection.

The inspectors completed 3 of the required 15 samples and 6 of the optional samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors sampled licensee submittals for the three performance indicators on both units listed below. The inspectors verified (1) the accuracy of the performance indicator data reported during that period and (2) used the performance indicator definitions and guidance contained in Nuclear Energy Institute Document 99-02, “Regulatory Assessment Indicator Guidelines,” Revision 2, to verify the basis in reporting for each data element.

Reactor Safety Performance Indicators

- Emergency AC power systems unavailability, Units 1 and 2
- HPSI unavailability, Units 1 and 2
- Safety system functional failures, Units 1 and 2

The inspectors reviewed operator log entries, daily shift manager reports, plant computer data, CRs, maintenance action item paperwork, maintenance rule data, and performance indicator data sheets to determine whether the licensee adequately verified the performance indicators listed above. The performance indicator valves reported by the licensee for the third calendar quarter of 2004 were compared to the numbers reported for the performance indicator during the past 3 quarters. Also, the inspectors interviewed licensee personnel responsible for compiling the information.

Emergency Preparedness Performance Indicators

- Drill and exercise performance
- Emergency response organization participation
- Alert and notification system reliability

The inspectors reviewed a 100 percent sample of drill and exercise scenarios, licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspectors reviewed the qualification, training, and drill participation records for a sample of 12 emergency responders. The inspectors reviewed alert and notification system maintenance records and procedures and a 100 percent sample of siren test results. The inspectors also interviewed licensee personnel that were responsible for collecting and evaluating the perforamance indicator data.

The inspectors completed three samples during this inspection.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Annual Sample Review

a. Inspection Scope

The inspectors chose issues for more in depth review to verify that licensee personnel had taken corrective actions commensurate with the significance of the issues. The issues and their bases for their selection is described below:

- Safety parameter display system (SPDS) for Units 1 and 2. In June 2003 SPDS was moved from a 10 CFR 50.65(a)(2) system to a 10 CFR 50.65(a)(1) system. Due to the recent recurrent failures of various SPDS components and the role SPDS plays in the event of a control room fire (alternate shutdown), this sample was chosen to ensure adequate measures were being implemented to return the system to a 10 CFR 50.65(a)(2) status.

- Control of containment penetrations for secondary systems in Units 1 and 2. In April 2003 in NRC Inspection Report 05000313/2003002; 05000368/2003002, inspectors documented an NCV associated with the control of these containment penetrations. The inspectors reviewed CR ANO-C-2003-0242 which the licensee used to track implementation of their decision to control these penetrations per General Design Criterion (GDC) 57, “Closed System Isolation Valves,” to determine if the CAP adequately resolved the issue.

When evaluating the effectiveness of the licensee’s corrective actions for these issues, the following attributes were considered:

- Complete and accurate identification of the problem in a timely manner commensurate with its significance and ease of discovery

- Evaluation and disposition of operability and reportability issues

- Consideration of extent of condition, generic implications, common cause, and previous occurrences

- Classification and prioritization of the resolution of the problem commensurate with its safety significance

- Identification of root and contributing causes of the problem for significant conditions adverse to quality

- Identification of corrective actions which are appropriately focused to correct the problem

- Completion of corrective actions in a timely manner commensurate with the safety significance of the issue

The inspectors completed two samples.

b. Findings

There were no findings identified associated with the two samples reviewed, however, the inspectors identified that the licensee was withholding final implementation of some corrective actions for no apparent reason. While the licensee made the decision to treat secondary system containment penetrations in accordance with GDC 57 controls in October 2003 the inspectors discovered in September 2004 that none of the subject penetrations were being controlled per GDC 57. The licensee had requested an exemption from the NRC Office of Nuclear Reactor Regulation for special treatment of three of these penetrations which was delaying implementation of corrective action. The licensee had not taken actions on any of the remaining penetrations and was waiting for approval of the exemption to implement GDC 57 controls on all the subject penetrations, despite no obstacles to applying GDC 57 controls to the penetrations not subject to the exemption request.

2. Cross-References to PI&R Findings Documented Elsewhere

Section 1R14 documents a condition where the operations staff failed to add missing procedural steps following similar occurrences in November 2002 and January 2003.

Section 4OA3 documents a condition where engineering personnel did not adequately question indications of abnormal containment cooling system operation after an outage where work had been performed on the containment cooling fans.

Section 4OA3 documents a condition where engineering personnel performed poor operability evaluations on a containment cooling fan on two occasions.

3. Observations with the Substantive Crosscutting Issue in PI&R

As a result of numerous findings dealing with the licensee's CAP, the NRC staff identified a substantive crosscutting issue in the area of PI&R during its annual assessment for inspections conducted in 2003. In this inspection quarter, inspectors made the following observations pertaining to the specific areas listed below which were identified as areas with implementation problems.

Problem Identification and Entry into the CAP

During the inspection period, the inspectors identified two examples of conditions that should have warranted entry into the CAP, but were only entered into the licensee's work control system. The first example was related to the need to overhaul the turbine-driven emergency feedwater pump service water inlet Valve CV-2806. The second example concerned a hand switch in the control room to operate Valve 2CV-5016-2 which was noted to be extremely loose in both the open and close direction. Maintenance action items were written to address these conditions but they were not entered into the CAP until questioned by the inspectors.

Section 4OA3 documents a condition where Unit 2 containment temperatures were noted to be questionable while running a containment cooling fan which was later found to be inoperable but was not entered into the CAP at that time.

Prioritizing and Evaluating Conditions in the CAP

Section 4OA2 documents a condition where a decision was made to pursue a course of action to treat secondary containment penetrations with GDC 57 controls but corrective action for all penetrations were not adequately prioritized.

The inspectors noted an occurrence where an operability evaluation only addressed current operability and not future operability in a CR for turbine-driven emergency feedwater pump service water inlet Valve CV-2806.

Section 4OA3 documents a condition where anomalies with containment Cooling Fan 2VSF-1B were noted but poor operability evaluations led to declaring Cooling Fan 2VSF-1B operable when it was not.

Implementing Effective Corrective Actions

Section 1R14 documents a condition where on several occasions rod malfunctions were received and cleared but effective corrective action to improve operations procedures were not accomplished.

Summary

The licensee implemented corrective actions to improve their CAP after receiving the substantive crosscutting issue in PI&R. The actions were detailed in CR ANO-C-2003-1080 and were completed June 30, 2004. Since then, the inspectors have documented observations associated with each of the noted problem areas each quarter. The inspectors have observed improvement in each of these areas.

4. Semi-Annual Trend Review

a. Inspection Scope

On December 30, 2004, the inspectors completed a semi-annual review of licensee internal documents, reports, audits, and performance indicators to identify trends that might indicate the existence of more significant safety issues. The inspectors reviewed the following:

- system health indicators
- temporary alterations
- CRs
- work requests
- maintenance rule failures

b. Findings

No findings of significance were identified. However, during the review, the inspectors observed the following issue which was discussed with licensee management:

- Licensee personnel documented 12 instances where control of high energy line break (HELB) doors were deficient. The number of instances and the variety of the issues included: (1) instances where HELB doors were not administratively controlled by procedures, (2) instances where HELB doors were found opened when they should have been closed, and (3) instances where HELB doors were not labeled. None of these instances actually challenged plant safety but the number of findings was indicative of a need for improved control of HELB doors. Licensee management was aware of this performance issue and has implemented corrective actions as set forth in CR ANO-1-2003-0258.

5. PI&R Review of ALARA Planning and Controls and Access Control to Radiologically Significant Areas

a. Inspection Scope

Section 2OS2 evaluated the effectiveness of the CAP regarding exposure tracking, higher than planned exposure levels, and radiation worker practices. The inspector reviewed the corrective action documents listed in the attachment against the CAP requirements.

b. Findings

No findings of significance were identified.

6. PI&R Review of Emergency Preparedness Exercises

a. Inspection Scope

The inspectors reviewed all CRs associated with the last three emergency preparedness exercises. Three CRs were selected for detailed review based on their linkage with event classification, notification of offsite authorities, and processes for providing protective action recommendations. The records were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

1. (Closed) Licensee Event Report (LER) 05000313/2004002-00, Operation Prohibited by Technical Specifications due to Degradation of a Physical Safety Barrier Caused by Primary Water Stress Corrosion Cracking of a Control Rod Drive Mechanism Nozzle (CRDM)

The reported condition involved two axial indications on the outside diameter of CRDM Nozzle 61. No evidence of a reactor coolant pressure boundary leakage was detected during the ultrasonic testing or observed in the bare metal visual examination. These axial indications were believed to be caused by due to primary water stress corrosion cracking. The licensee captured the nozzle repair and other corrective actions in CR ANO-1-2004-0819. The inspectors reviewed the LER and identified no findings of significance. This LER is closed.

2. (Closed) LER 05000368/2004002-00, Operation Prohibited by Technical Specification due to an Inoperable Containment Cooling Fan Resulting from the Failure to Perform an Adequate Verification and Postmaintenance Test

a. Inspection Scope

The inspectors reviewed this LER and CR ANO-2-2004-1688, which documented the discovery of the condition in the CAP, to verify that the cause of Containment Cooling Fan 2VSF-1B inoperability was identified and corrective actions were appropriate. The inoperability of the containment fan cooler was caused by improper rewiring of the fan after maintenance. The inspectors also reviewed plant logs, interviewed cognizant operations and engineering personnel, reviewed the licensee’s root cause report, and reviewed other CRs in the CAP pertinent to Containment Cooling Fan 2VSF-1B.

b. Findings

Introduction. The inspectors reviewed an apparent violation of Unit 2 Technical Specification 3.6.2.3, “Containment Cooling Systems,” when the Containment Cooling Fan 2VSF-1B was discovered to be inoperable over 11-months.

Description. On September 29, 2004, the licensee discovered that Containment Cooling Fan 2VSF-1B was rotating backwards. Further investigation into the cause of the fan rotating backwards was a wiring error which had been accomplished over 11-months earlier as described in Section 1R19 of this report. The inspectors concluded that the following opportunities existed to diagnose the problem prior to the discovery on September 29, 2004:

- On October 14, 2003, after Refueling Outage 2R16 had ended, engineering and operations personnel noticed that containment temperatures appeared higher than normal when Containment Cooling Fan 2VSF-1B was running. Initial questions were raised but no evaluation was performed. These concerns were not documented in the CAP until March 11, 2004.

- On March 10, 2004, while evaluating CR ANO-2-2004-0510, engineering personnel noted a correlation between the increased containment temperatures and operation of Containment Cooling Fan 2VSF-1B, bringing into question the operability of Containment Cooling Fan 2VSF-1B. The licensee performed an operability evaluation which concluded that Containment Cooling Fan 2VSF-1B was operable based on engineering judgement. This conclusion was based largely on satisfactory inspection and test performance of the cooler during Refueling Outage 2R16. It did not consider the possibility of a maintenance error during the containment penetration over current device testing on October 2, 2003. This testing was overlooked during a search of maintenance done to Containment Cooling Fan 2VSF-1B . The evaluation focused on the possibility of a misaligned air flow damper or partial clogging of service water flow to the cooler’s heat exchanger, both of which would not have rendered Containment Cooling Fan 2VSF-1B inoperable. Corrective actions for this CR required an inspection of Containment Cooling Fan 2VSF-1B during the next containment entry of sufficient scope or during the next refueling outage.

- On September 27, 2004, during a forced outage on Unit 2 to repair a feedwater leak, a containment entry was made to inspect the containment cooling system. Based on this, engineers generated CR ANO-2-2004-1673 to document that a damper associated with Containment Cooling Fan 2VSF-1B was stuck in an intermediate position. Engineers performed an operability evaluation which concluded that the fan was operable based on engineering judgement because adequate flow for accident mitigation still existed even with the damper stuck in an intermediate position. Engineering management questioned the validity of this conclusion and directed a second evaluation since the first evaluation assumed a stuck damper, not a fully shut damper which would have been more conservative. A second inspection of Containment Cooling Fan 2VSF-1B was conducted which indicated that no damper problem existed.

On September 29, 2004, after further investigation, maintenance personnel discovered that the fan was not wired in accordance with its electrical diagram. The licensee subsequently fixed the wiring discrepancy and restored the operability of Containment Cooling Fan 2VSF-1B. Because the licensee took 11 months and 25 days to determine that the fan was inoperable, the licensee operated Unit 2 in excess of the 7 day allowed outage time for an inoperable containment cooler specified in Technical Specification 3.6.2.3.

Analysis. Operation of Unit 2 with Containment Cooling Fan 2VSF-1B in an inoperable condition was considered to be a performance deficiency since it was reasonably within the licensee's ability to diagnose and correct this condition. This finding affected the Mitigating Systems and Barrier Integrity cornerstones and was more than minor because it affected the mitigating systems cornerstone objective of ensuring the availability of systems which respond to initiating events. The Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required since two reactor safety cornerstones were affected. As a result, the inspectors performed a Phase 2 analysis using Appendix A, "Technical Basis For At Power Significance Determination Process," of Manual Chapter 0609, "Significance Determination Process," and the Phase 2 worksheets from "Risk-Informed Inspection Notebook for Arkansas Nuclear One - Unit 2." The inspectors assumed that the duration of the inoperability of the containment fan cooler was 11 months and 25 days and that operations personnel would not be able to recover the containment cooler. Inspectors also assumed all other containment coolers remained operable throughout the 11months, 25 days exposure time. The dominant core damage sequences involved a loss of AC or DC busses, a failure of emergency feedwater, and a failure of containment spray recirculation. Specifically, the small break loss of coolant accident and stuck open relief valve sequences were most limiting. A review of the Phase 2 estimation and performance of a Phase 3 analysis by a regional senior reactor analyst is needed to determine the final safety significance of the finding. This issue involved PI&R crosscutting aspects associated with (1) engineers not adequately questioning indications of abnormal containment cooling system operation and (2) engineering personnel performing poor operability evaluations.

Enforcement. Unit 2 Technical Specification 3.6.2.3, "Containment Cooling Systems," requires that two independent containment cooling groups shall be operable with two operational cooling units in each group. With one group of containment cooling units inoperable, the inoperable group of cooling units must be restored to an operable condition within 7 days. Contrary to this, from October 2, 2003, through September 29, 2004, the fan for Containment Cooling Fan 2VSF-1B was wired incorrectly and was not operable for 11 months and 25 days, well in excess of 7 days. Pending determination of the findings final safety significance, this violation is being treated as an apparent violation, consistent with Section VI.A of the NRC Enforcement Policy: AV 05000368/2004005-05, "Containment Cooler Fan Inoperable in Excess of Technical Specification Allowed Outage Time."

4OA4 Crosscutting Aspects of Findings

Cross-Reference to Human Performance Findings Documented Elsewhere

Section 1R12 describes a condition where system engineers failed to ensure that failures that should have been revised by other cognizant system engineers were tracked in the maintenance rule database when not counted against their system.

Section 1R14 describes a condition where control room operators failed to involve senior management upon discovery that procedural guidance was not available for current plant conditions.

Section 1R19 describes a condition where electricians improperly wired a containment cooling fan which led to inoperability of the containment cooler.

Section 1R19 also describes a condition where outage management personnel deferred postmaintenance testing on a containment cooling fan flow switch which could have detected an inoperable containment cooling fan.

4OA5 Other Activities

1. Review of Third Party Evaluation

A review of a biennial evaluation and assessment conducted by the Institute of Nuclear Power Operations was completed by the inspectors.

2. (Closed) URI 05000313/2004004-04, Untimely Corrective Action to Fix Oil Leak Renders EDG Inoperable

Introduction. A Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified for the repeated failures of licensee personnel to promptly identify and correct degraded conditions associated with Unit 1 EDG K-4B Temperature Switch TSH-5271.

Description. Unresolved Item 05000313/2004004-04 documented a concern regarding the timeliness of corrective actions for an oil leak on the Unit 1 EDG K-4B. The leak was on the temperature switch for the lubricating oil scavenging pump Discharge TSH-5271 and had the potential to degrade to the point where the EDG would not have been able to fulfil its safety function. This finding potentially had a safety significance greater than very low significance and was made unresolved pending the determination of the duration of the condition and a review of the safety significance by the regional senior reactor analyst. Based on further evaluation, this degraded condition was determined to have existed for a five day period, during which it had the potential for rendering the EDG inoperable. The licensee implemented corrective actions in July 2004 to repair this oil leak.

Analysis. The inspectors determined that the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of equipment availability and reliability. Therefore, the finding is greater then minor. Using the Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," the inspectors determined that the finding was of very low safety significance since the condition that would have rendered the EDG inoperable only existed for five days which was less than the allowed outage time in the Technical Specifications. In addition, this finding did not screen as risk significant due to external initiating events.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that licensees promptly identify and correct conditions adverse to quality. Contrary to the above, from May 18 to July 2, 2004, the licensee did not promptly identify and implement actions to repair a degrading fitting on Temperature Switch TSH-5271 resulting in EDG K-4B being inoperable for over 5-days. Because of the very low safety significance and because the licensee included this condition in the CAP as CR ANO-1-2004-1705, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000313/2004005-06, "Untimely Corrective Action to Fix Oil Leak Renders EDG Inoperable."

3. (Closed) AV 05000368/2004004-05, Failure to Identify and Correct a Loose Circuit Connection in Containment Spray Circuitry

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion XV, "Nonconforming Materials, Parts, or Components," for the licensee's failure to establish controls to prevent a breaker with a loose connection from being installed in Unit 2.

Description. During a quarterly surveillance test on May 20, 2004, Unit 2 Containment Spray Pump 2P-35A failed to start. This was the first instance of this pump failing to start since the licensee replaced the 4160 VAC breaker in 2001. Licensee personnel conducted troubleshooting to diagnose the cause of the pump failure and found elevated resistance across the contacts for Relay LS-9 in the breaker's closing circuit. Convinced that this was the cause of the breaker failure, the licensee replaced Relay LS-9 and returned the breaker and pump to service. During postmaintenance testing, the breaker was cycled satisfactorily 11 times and the pump started with the breaker racked-in.

On June 3, 2004, engineering personnel contacted the breaker vendor, Siemens, to inform them of their findings with the high resistance across the contacts. The vendor refuted the licensee's finding stating that any resistance would have been burned through by the 250 volts DC supplied to the breaker's closing circuit during the start sequence. The vendor recommended that the licensee check other parts of the circuit to identify the cause of the failed breaker.

On August 9, 2004, the licensee racked out the containment spray pump breaker for further troubleshooting and discovered that a spade-lug connection leading to the anti-pump relay in the closing circuitry was loose. The spade was not completely inserted into the lug, giving intermittent elevated resistance readings to the relay technicians who were troubleshooting the breaker. The inspectors noted that the licensee delayed additional inspections of the breaker even though the vendor had provided information which contradicted their cause of the breaker's failure mechanism.

During conversations after the discovery, one licensee technician noted that he had discovered five or six similar loose connections while performing receipt inspections of this group of breakers in 2000. The inspectors questioned whether a CR had been written to document the discovery of loose connections during the receipt inspection process. The licensee explained that the receipt inspection procedure for the breakers instructed the technicians to tighten loose connections as necessary. As a result, the technician simply inserted the spade into the lug for the loose connections he discovered and did not document the deficiency on the receipt inspection sheet. The technician did inform other technicians performing receipt inspections of the deficiency. Because the loose connections were not recorded individually, a deficiency report was not generated and corrective actions to inspect all other spade-lug connections in the group of breakers was not initiated. As a result, a breaker with a loose connection was installed into the plant for the Unit 2 Containment Spray Pump 2P-35A.

The inspectors noted that Maintenance Action Item 26147 (used to inspect the breakers) required that all deficiencies be recorded. The inspectors concluded that the loose connections should have been documented. The inspectors noted that after the failure of the pump to start on May 21, 2004, the degraded circuit connection was not discovered and was left in place for 2 additional months, until August 9 due to licensee personnel incorrectly considering Relay LS-9 as the cause of the failure of the containment spray pump to start.

Analysis. The failure to establish adequate measures to prevent breakers with loose circuit connections from being installed in the plant was considered to be a performance deficiency. This finding is more than minor because it is analogous to Example 5.c of Appendix E, “Examples of Minor Issues,” of Manual Chapter 0612, “Power Reactor Inspection Reports,” because a nonconforming component was installed in the plant and the system it was in was returned to service. Using the Phase 1 worksheets in Manual Chapter 0609, “Significance Determination Process,” the inspectors determined that the finding effected the mitigating systems and barrier integrity cornerstones. As a result, the inspectors performed a Phase 2 estimation using Appendix A, “Technical Basis For At Power Significance Determination Process,” of Manual Chapter 0609, “Significance Determination Process,” and the Phase 2 worksheets from “Risk-Informed Inspection Notebook for Arkansas Nuclear One - Unit 2.” The Phase 2 estimation determined that the finding was potentially of greater than Green safety significance. The inspectors assumed that the duration was greater than 30-days and that operations personnel would be able to recover the containment spray pump by starting it from the switchgear room. The dominate core damage sequences involved a loss of AC or DC busses, a failure of emergency feedwater, and a failure of containment spray recirculation. Specifically, the small break loss of coolant accident and stuck open relief valve sequences were most limiting. A review of the Phase 2 analysis and performance of a Phase 3 analysis by a regional senior reactor analyst determined the finding to be of very low safety significance because, since the circuit fault was intermittent and the pump could have been easily started locally at the breaker if needed. Details of the Phase 3 analysis are included as Attachment 2 to this report.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XV, requires that licensees establish measures to control components which do not conform to requirements in order to prevent their inadvertent use. Contrary to the above, licensee personnel did not establish adequate measures during the breaker receipt inspection process in October 2000 to prevent breakers with loose circuit connections from being installed in the plant. As a result, the breaker was installed in the cubicle for the Unit 2 containment spray pump breaker in February 2001. Because of the very low safety significance and because the licensee included this condition in the CAP as CR ANO-2-2004-0922, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000368/2004005-07, "Failure to Identify and Correct a Loose Circuit Connection in Containment Spray Pump Circuitry."

4OA6 Meetings, Including Exit

On October 8, 2004, the inspectors presented the inspection results to Ms. R. Partridge, Manager, Technical Support and other members of her staff who acknowledged the findings.

The inspectors presented the emergency preparedness exercise inspection results to Mr. J. Forbes, Vice President, and members of his staff at the conclusion of the inspection on October 22, 2004. The licensee acknowledged the findings presented.

The resident inspectors presented the inspection results to Mr. C. Eubanks, General Manager, Plant Operations, and other members of licensee management on January 6, 2005. The licensee acknowledged the findings presented.

The inspectors noted that while proprietary information was reviewed, none would be included in this report.

4OA7 Licensee-Identified Violations

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

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be accomplished in accordance with prescribed instructions. On October 6, 2004, during fuel assembly movements in the Unit 2 spent fuel pool, fuel handlers did not move Spent Fuel Assembly AKR419 to Unit 2 Spent Fuel Location AA-25 in accordance with Nuclear Transfer Report 2-17-56, but instead moved the fuel assembly to Spent Fuel Location A-25. This event is documented in the licensee's CAP as CR ANO-2-2004-1937. This finding is only of very low safety significance because the licensee's criticality analysis was not violated and no

fuel barriers were degraded.

ATTACHMENT 1: SUPPLEMENTAL INFORMATION

ATTACHMENT 2: FAILURE TO IDENTIFY NON CONFORMING CONTAINMENT SPRAY PUMP BREAKER PHASE 3 ANALYSIS

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

B. Berryman, Manager, Planning and Scheduling
T. Brown, Supervisor, Radiation Protection
S. Cotton, Manager, Training
J. Eichenberger, Manager, Corrective Actions and Assessments
C. Eubanks, General Manager, Plant Operations
J. Forbes, Vice President, Arkansas Nuclear One
F. Forrest, Manager, Operations, Unit 1
R. Fowler, Sr. Emergency Planner
R. Freeman, Emergency Planning Specialist
R. Gresham, Emergency Planner
C. Harris, Emergency Planner
A. Hawkins, Licensing Specialist
A. Heflin, Manager, Operations, Unit 2
G. Hines, Maintenance Rule Coordinator
J. Hoffpauir, Manager, Maintenance
R. Holeyfield, Manager, Emergency Planning
D. James, Acting Director, Nuclear Safety Assurance
J. Kowalewski, Director, Engineering
J. Miller, Manager, Systems Engineering
D. Moore, Superintendent, Radiation Protection
K. Nichols, Manager, Design Engineering
R. Partridge, Manager, Technical Support
S. Pyle, Licensing Specialist
C. Reasoner, Manager, Engineering Programs and Components
R. Scheide, Licensing Specialist
D. Stoltz, Specialist, Radiation Protection
C. Tyrone, Manager, Quality Assurance
D. White, Emergency Planner

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000368/2004005-01	NCV	Failure to Establish Adequate Measures to Demonstrate the Performance or Condition of the Unit 2 Pressurizer Proportional Heaters (Section 1R12)

05000368/2004005-02	NCV	Failure to Include Nonsafety Related Components that Affect Safety-Related Functions into the Maintenance Rule Program (Section 1R12)
05000313/2004005-03	NCV	Operator Action due to Inadequate Procedure Results in Momentary Increase in Reactor Power Above Rated Thermal Power (Section 1R14)
05000313/2004005-06	NCV	Untimely Corrective Action to Fix Oil Leak Renders EDG Inoperable (Section 4OA5)
05000368/2004005-07	NCV	Failure to Identify and Correct a Loose Circuit Connection in Containment Spray Pump Circuitry(Section 4OA5)

Opened

05000368/2004005-04	AV	Two Examples of Failure to Conduct Postmaintenance Testing Associated with a Containment Cooler Fan (Section 1R19)
05000368/2004005-05	AV	Containment Cooler Fan Inoperable in Excess of Technical Specification Allowed Outage Time (Section 4OA3)

Closed

05000313/2004002-00	LER	Operation Prohibited by Technical Specifications due to Degradation of a Physical Safety Barrier Caused by Primary Water Stress Corrosion Cracking of a CRDM Nozzle (Section 4OA3.1)
05000368/2004002-00	LER	Operation Prohibited by Technical Specification due to an Inoperable Containment Cooling Fan Resulting from the Failure to Perform an Adequate Verification and Postmaintenance Test (Section 4OA3.2)
05000368/2004004-04	URI	Untimely Corrective Action to Fix Oil Leak Renders EDG Inoperable (Section 4OA5)
05000368/2004004-05	AV	Failure to Identify and Correct a Loose Circuit Connection in Containment Spray Pump Circuitry (Section 4OA5)

Discussed

None

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R04: Equipment Alignment

Operating Procedures

NUMBER	TITLE	REVISION
1104.029	Service Water and Auxiliary Cooling System	56
2104.029	Service Water System Operation	54

Plant Documents

NUMBER	TITLE	REVISION
ULD-2SYS-10	Arkansas Nuclear One Upper Level Document - ANO 2 Service Water System	9
	Unit 2 Safety Analysis Report Section 9.2 “Water Systems”	Amendment 18

Plant Drawings

M-209 Sheet 1, Revision 105
M-2210 Sheet 1, Revision 84

Section 1R05: Fire Protection

Engineering Calculation

85-E-0053-15, Revision 45

Plant Documents

TITLE	REVISION
Arkansas Nuclear One Fire Hazards Analysis Report,	8

Plant Drawings

NUMBER	TITLE	REVISION
FP-2104	Fire Zone Ground Floor Plan at Elev. 354' - 0"	29, Sheet 1
FP-2104	Fire Zone Plan at Elev. 317' - 0"	13, Sheet 1
FP-2111	Fire Zone Emergency Diesel Fuel Storage Vault	6, Sheet 1

Section 1R12: Maintenance Effectiveness

CRs

ANO-C-2004-1791	ANO-2-2002-1354	ANO-2-2004-1727
ANO-C-2004-1961	ANO-2-2004-0223	ANO-2-2004-1735
ANO-C-2004-2208	ANO-2-2004-1709	ANO-2-2004-1743
ANO-2-1994-0255	ANO-2-2004-1713	ANO-2-2004-1753
ANO-2-1998-0117	ANO-2-2004-1714	ANO-2-2004-1793
ANO-2-1998-0141	ANO-2-2004-1716	ANO-2-2004-1867
ANO-2-2001-0349	ANO-2-2004-1722	
ANO-2-2001-0440	ANO-2-2004-1726	

Drawings

NUMBER	TITLE	REVISION
M-2204	Piping & Instrument Diagram Emergency Feedwater	63, Sheet 4
M-2229	Piping & Instrument Diagram Start-Up & Blowdown Demineralizer System	76

Operating Procedures

NUMBER	TITLE	REVISION
2102.004	Power Operation	29
2107.001	Electrical System Operations	49

Miscellaneous

NUMBER	TITLE
05000368/2004003-00	Entry into an Operational Mode Prohibited by Technical Specification due to Inoperable Pressurizer Proportional Heaters
Maintenance Rule Database	Unit 2, Emergency Feedwater System
Maintenance Rule Database	Unit 2, Reactor Coolant System
Maintenance Rule Database	Unit 2, 480 V Load Centers & Motor Control Centers

Work Order

50248377	50254408
50254407	50390831

Section 1R16: Operability Work-Arounds

CRs

ANO-C-2004-0740

Miscellaneous

OWA 1-04-01 through OWA 1-04-15
OWA 1-03-09
OWA 1-03-05
OWA C-04-01
OWA C-03-01
OWA 2-04-01 through OWA 2-04-05
OWA 2-02-02
OWA 2-00-04

Section 1R19: Postmaintenance Testing

CRs

ANO-2-2004-1713
ANO-2-2004-1716
ANO-2-2004-1727
ANO-2-2004-1974

Work Orders

00052311-01
00052582-01
00052582-04
00052582-05
00052582-06
00053439-01

Section 1R22: Surveillance Testing

CRs

ANO-1-2004-0873

Engineering Calculation

ER 991372
ER-ANO-2002-0534-00

Operating Procedures

NUMBER	TITLE	REVISION
1305.018	Local Leak Rate Testing - Type C	14
2304.024	Unit 2 Containment Sump Level Calibration	12
2403.001	Unit II 2D11 Performance Test Electrical Maintenance	9

Work Order Packages

00053590-01	50572640-01	50965945-01
50276330-00	50573551-01	50965963-01
50268458-01	50684768-01	50966911-01
50269304-01	50965634-01	50978930-01
50276820-01		

Section 1R23: Temporary Plant Modifications

CRs

ANO-1-2004-2206

Engineering Reports

CALC-94-R-0022-02	ER963555R112
CALC-95-R-0024-01	ER963555E101

Procedures

NUMBER	TITLE	REVISION
COPD003	Door Breach Checklist	9
OP 1000.152,	Unit 1 & 2 Fire Protection System Specifications	3
OP 1306.005	Fire Door Inspection Procedure	20
OP 2306.025	Unit 2 Fire Door Inspection Procedure,	6

Section 1EP1: Exercise Evaluation

NUMBER	TITLE	REVISION
1903.011-Y	Initial Notification Message Form	29
1903.011-Z	Initial Notification Message Form Instructions	29
1903.011	Protective Action Recommendations for General Emergency	27 Attachment 6
	Protective Action Recommendations for General Emergency	
	Summary of Emergency Preparedness exercise related CRs for last three exercises	
	Formal Management Critique of October 20, 2004 Biennial Exercise	

Section 1EP4: Emergency Action Level and Emergency Plan Changes

TITLE	REVISION
Arkansas Nuclear One Emergency Plan	30
10 CFR 50.54(q) Evaluation for Arkansas Nuclear One Emergency Plan	28, 29, 30

Section 2OS2: ALARA Planning and Controls

CRs

1-2004-0744	2-2004-0655	C-2004-1016
1-2004-0866	2-2004-0718	C-2004-1628
1-2004-0880	C-2004-0663	LO-ALO-2004-0031
1-2004-1171	C-2004-0739	LO-ALO-2004-0190
1-2004-1235	C-2004-1015	

Audits and Self-Assessments

NUMBER	TITLE
QA-14-2004-ANO-1	Radiation Protection Audit Report
QS-2004-ANO-005	1R18 Outage Surveillance for Radiation Protection

Radiation Work Permits

NUMBER	TITLE
2004-1420	Remove/Replace Scaffold and Insulation
2004-1442	Steam Generator Inspection and Repair
2004-1452	A600 Repair of CRDM Nozzles/Including Support
2004-1453	A600 Inspection of CRDM Nozzles/Including Support
2004-1468	A600 Inspection of Bottom Mounted ICI Nozzles/Including Support

Procedures

NUMBER	TITLE	REVISION
PL-182	Radiation Protection Expectations and Standards	1
RP-105	Radiation Work Permits	5
RP-109	Hot Spot Program,	0
RP-110	ALARA Program	2

RP-205	Prenatal Monitoring	2
1601.003	Control of Temporary Shielding	8

ALARA Sub Committee Meeting Minutes

March 25, 2004
April 15, 2004
September 30, 2004

ALARA Managers Committee Meeting Minutes

April 28, 2004
July 8, 2004
September 30, 2004

Emergency Plan Implementing Procedures (EPIPs)

NUMBER	TITLE	REVISION
1903.003	Assignment of Personnel to the Emergency Response Organization	15
1903.010	Emergency Action Level Classification	37
1903.011	Emergency Response/Notifications	27
1903.033	Protective Action Guides for Rescue/Repair and Damage Control Teams	18
1903.035	Administration of Potassium Iodide	7
1903.064	Emergency Response Facility - Control Room	7
1903.065	Emergency Response Facility - Technical Support Center (TSC)	16
1903.066	Emergency Response Facility - Operations Support Center (OSC)	13
1903.067	Emergency Response Facility - Emergency Operations Facility (EOF)	18
1903.068	Emergency Response Facility - Emergency News Center (ENC)	8
Company Policy No. PL-140	Emergency Response Organization Respiratory Protection Guidelines	2
Entergy Procedure EN-EP-201	Emergency Planning Performance Indicators	1

Drill and Exercise Reports

DATE	TITLE
April 2003-September 2004	Simulator Shift Training and Communicator Drills
February 27, 2002	Team Exercise
May 28, 2003	Team (D) Exercise
November 5, 2003	Team (B) Exercise
September 15, 2004	Team (A) Exercise

Section 4OA2: Identification and Resolution of Problems

CRs

ANO-C-2003-0453	ANO-C-2004-2149
ANO-C-2004-2129	ANO-1-2004-2381
ANO-C-2004-2133	ANO-1-2004-2402
ANO-C-2004-2140	

NUMBER	TITLE
LO-OPX-2004-00231	Evaluate NRC's RIS 2004-13, Consideration of Sheltering in Licensee's Range of Protection Action Recommendations, for effect to each Site's EP program
CR-ANO-C-2004-01923	Review of NRC Regulatory Issue Summary (RIS) 2004-13
NRC RIS 2004-13	Consideration of Sheltering in Licensee's Range of Protection Action Recommendations

Work Order

50981954

Work Request

00040452

Section 4OA3: Event Followup

CRs

ANO-C-2004-1791	ANO-2-2002-1354	ANO-2-2004-1727
ANO-C-2004-2116	ANO-2-2004-0223	ANO-2-2004-1728
ANO-C-2004-2208	ANO-2-2004-1709	ANO-2-2004-1735
ANO-2-1994-0255	ANO-2-2004-1713	ANO-2-2004-1793
ANO-2-1998-0117	ANO-2-2004-1716	ANO-2-2004-1867
ANO-2-1998-0141	ANO-2-2004-1726	ANO-2-2004-1961

Miscellaneous

NUMBER	TITLE
LIC-04-032	Technical Specification Actions for ANO-2 Pressurizer Proportional Heaters
LIC-04-045	Technical Specification Requirements for ANO-2 Pressurizer Proportional Heaters
LIC-04-046	Application of ANO-2 EDG TSs With Regard to the Pzr Proportional Heaters”
LIC-04-047	TS AOT Reset During Failure of Redundant Components”

Operating Procedure

NUMBER	TITLE	REVISION
1015.036	Containment Building Closeout	11
1015.047	Condition Reporting Operability and Immediate Reportability Determinations	1
2102.002	Plant Heatup	52
2107.001	Electrical System Operations	49
2305.016	Remote Feature Periodic Testing	16
2307.009	Pressurizer Proportional Heater Checkout	6

Work Orders

00052582-01	50248377
00052582-04	50254407
00052582-05	50254408
00052582-06	50390831

LIST OF ACRONYMS

ALARA	as low as reasonably achievable
ANO	Arkansas Nuclear One
CAP	corrective action program
CFR	*Code of Federal Regulations*
CR	condition report
CRD	control rod asymmetric
CRDM	control rod driven mechanism
EDG	emergency diesel generator
GDC	general design control
GDC	general design criteria
HELB	high energy line break
HPSI	high pressure safety injection
LER	licensee event report
NCV	noncited violation
PI&R	problem identification and resolution
SPDS	safety parameter display system
SSC	structure, system, and component

ATTACHMENT 2

ARKANSAS NUCLEAR ONE
Failure to Identify Nonconforming Containment Spray Pump Breaker
Phase 3 Analysis

I. Performance Deficiency:

Licensee personnel failed to identify a loose connection in the Containment Spray Pump 2P-35A breaker prior to installation in the plant. Several undocumented instances where similar loose connections were discovered during receipt inspections of other breakers. This resulted in the pump failing to start on May 20, 2004, during a routine surveillance.

II. Safety Significance:

The analyst determined that the performance deficiency represented a finding of very low risk significance. This was based on a Phase 3 evaluation using NRC Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations."

III. Description of Condition:

During a quarterly surveillance test on May 20, 2004, Unit 2 Containment Spray Pump 2P-35A failed to start. This was the first instance of this pump failing to start since the licensee replaced the 4160 VAC breaker in 2001. Licensee personnel conducted troubleshooting to diagnose the cause of the pump failure and found elevated resistance across the contacts for Relay LS-9 in the breaker's closing circuit. Convinced that this was the cause of the breaker failure, the licensee replaced Relay LS-9 and returned the breaker and pump to service. During postmaintenance testing, the breaker was cycled satisfactorily 11 times and the pump started with the breaker racked-in.

On June 3, 2004, engineering personnel contacted the breaker vendor, Siemens, to inform them of their findings with the high resistance across the contacts. The vendor refuted the licensee's finding stating that any resistance would have been burned through by the 250 volts dc supplied to the breaker's closing circuit during the start sequence. The vendor recommended that the licensee check other parts of the circuit to identify the cause of the failed breaker.

On August 9, 2004, the licensee racked out the containment spray pump breaker for further troubleshooting and discovered that a spade-lug connection leading to the anti-pump relay in the closing circuitry was loose. The spade was not completely inserted into the lug, giving intermittent elevated resistance readings to the relay technicians, who were troubleshooting the breaker. The inspectors noted that the licensee delayed additional inspections of the breaker even though the vendor had provided information which contradicted their cause of the breaker's failure mechanism.

During conversations after the discovery, one licensee technician noted that he had discovered five or six similar loose connections while performing receipt inspections of this group of breakers in 2000. The licensee explained that the receipt inspection procedure for the breakers instructed the technicians to tighten loose connections as necessary. As a result, the technician simply inserted the spade into the lug for the loose connections he discovered and did not document the deficiency on the receipt inspection sheet. The technician did inform other technicians performing receipt inspections of the deficiency. Because the loose connections were not recorded individually, a deficiency report was not generated, and corrective actions to inspect all other spade-lug connections in the group of breakers was not initiated. As a result, a breaker with a loose connection was installed into the plant for the Unit 2 Containment Spray Pump 2P-35A.

The inspectors noted that Maintenance Action Item 26147 (used to inspect the breakers) required that all deficiencies be recorded. The inspectors concluded that the loose connections should have been documented. The inspectors noted that after the failure of the pump to start on May 21, 2004, the degraded circuit connection was not discovered and was left in place for 2 additional months, until August 9 because licensee personnel incorrectly considered Relay LS-9 as the cause of the failure of the containment spray pump to start.

IV. Initial Characterization of Risk:

In accordance with NRC Inspection Manual Chapter 0612, Section 05.03, “Screen for Minor Issues,” the inspectors reviewed the sample minor findings in Appendix E, “Example of Minor Issues.” This performance deficiency was similar to Example 3.b, because it was a design discrepancy that resulted from an oversight of licensee personnel. However, the subject deficiency met the “not minor if,” criteria, in that, the operation of the systems were adversely affected by the performance deficiency.

The inspectors evaluated the issue using the SDP Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in NRC Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." The screening indicated that a Phase 2 estimation was required because the performance deficiency was assumed to degrade two cornerstones. Specifically, at Arkansas Nuclear One, Unit 2, the containment spray system provides cooling to the containment sump following a recirculation actuation signal that is part of the equipment performance attribute of the Mitigating Systems cornerstone. Additionally, the containment spray system provides the pressure suppression function for containment. This is part of the SSC and barrier performance attribute of Barrier Integrity cornerstone.

In accordance with NRC Inspection Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations," the inspectors evaluated the subject finding using the Risk-Informed Inspection Notebook for Arkansas Nuclear One, Unit 2, Revision 1. The following assumptions were made:

- The containment spray pump would fail to start on demand because the breaker would fail to close.

- The pump failed on May 21, 2004, and had last been started on February 27, 2004. The exposure window was assumed to be half the time between successful starts of the pump. This resulted in an exposure window of greater than 30-days.

- The pump could have been restarted remotely by operating the breaker at the main switchgear. This action would have bypassed the improper connnection and permitted starting of the pump.

Table 2 of the risk-informed notebook requires that all initiating event scenarios with the exception of LSW be evaluated when a performance deficiency affects the containment spray system. The dominant sequences from the notebook were as follows:

Initiating Event	Sequence	Mitigating Functions	Results
Transient with Loss of Power Conversion System	4	EFW-CSR	9
Small-Break LOCA	3	CSR	6
Medium-Break LOCA	2	CSR	7
Stuck-Open Relief Valve	2	CSR	6
Large-Break LOCA	4	CSR	8
Loss of Offsite Power with Failure of EAC	2	SOSV-CSR	8
	6	EFW-CSR	7
Loss of DC Bus 2D02	5	EFW-CSR	7
Loss of AC Bus 2A4	4	EFW-CSR	9
Loss of Service Water Loop 2	4	EFW-CSR	8
Loss of Nuclear Side of CCW	5	RCPTRIP-CSR	9

Using the counting rule worksheet, this finding was estimated to be YELLOW. However, several assumptions made during the Phase 2 process were overly conservative including the assumption that Pump 2P35A would always fail and the assumption that operator recovery would fail 10 percent of the time. Therefore, a Phase 3 evaluation was required.

V. Phase 3 Analysis:

Internal Initiating Events

Assumptions:

The results from the notebook estimation were compared with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of the failure of the containment spray pump, as well as an assessment of the licensee's assessment provided by the licensee's probabilistic risk assessment staff (Mike Lloyd). The SPAR runs were based on the following analyst assumptions:

a The SPAR Model, Revision 3.11, was used to assess the significance of this event. This model, including the component test and maintenance basic events, represents an appropriate tool for evaluation of the subject finding.

b Basic Event CSR-MDP-FS-2P35A can be further modeled as a fault tree indicating various ways that the pump can fail to start and including operator recovery actions. Fault Tree P35A-FTS (Attachment 1), developed by the analyst, properly represents the failure-to-start logic for both the baseline situation and for analysis of the subject finding.

c Seventy-five percent of all motor-driven pump failures occur as a result of breaker failures. This was taken from NUREG-1715, Volume 2, "Component Performance Study - Motor-Driven Pumps, 1987-1998."

d The analyst determined that the subject breaker had been cycled at least 30 times since installation. These included 15 cycles for quarterly surveillance testing, 13 cycles conducted by licensee technicians following the failure, and 2 cycles for the postmaintenance test conducted on May 21, 2004. Only one failure occurred in all these demands.

e The condition existed from February 2, 2001, when the breaker was installed, to August 9, 2004, when the condition was repaired. Therefore, an exposure time of 1 year (the reactor oversight process assessment period) was used.

f The Pump 2P35A breaker would not have failed from a mechanism similar to its May 20, 2004, failure had the performance deficiency not existed.

g Recovery from specific failure was considered to be highly likely. The conditional probability of operators failing to properly diagnose and close the containment spray pump breaker locally was 2.2×10^{-3}. The analyst used the SPAR-H method to calculate this probability. All performance shaping factors not discussed below were assumed to be at nominal value. The nominal diagnosis failure rate of 0.01 and the nominal action failure rate of 0.001 were multiplied by the following performance shaping factors:

, Available Time for Diagnosis: 0.1
Available Time for Action: 0.1

The analyst determined that there would be extra time to diagnose that the pump had not started. Additional, time would then be needed to determine that the problem could be bypassed locally. There is plenty of indication in the main control room for the diagnosis, and containment spray is not immediately needed to cool the sump.

The available time to take action was five times nominal. Local breaker operation at the switchgear should take no more than 20 minutes to accomplish including proper safety precautions.

, Stress: 2

Stress under the conditions postulated would be high. A major accident would be ongoing. Multiple alarms would be initiated when the pump failed. Additionally, operators would understand that the consequences of their actions would represent a threat to plant safety.

Analysis:

As stated in Assumption b, the analyst developed the Basic Event CSR-MDP-FS-2P35A into Fault Tree P35A-FTS (Attachment 1). The tree divided the basic event into failures of the breaker and equipment problems with the pump itself. The analyst also added a recovery basic event, Event CSR-OP-ACTION, with a baseline probability of 2.2×10^{-3} as described in Assumption g. This event represents the probability that operators fail to recovery from the specific failure caused by this performance deficiency which was assumed to be highly likely. Event CSR-OP-ACTION was coupled under an OR gate with Basic Event CSR-BAD-CLIP indicating the probability that the breaker did not fail from the deficiency related to this finding. Therefore, the model only applies recovery for the specific failure mode being analyzed. Event CSR-BAD-CLIP was initially set to the house event "FALSE," assuming that, sans the performance deficiency, the breaker would not fail from this mechanism as indicated by Assumption f. The SPAR was rebaselined, and this modified model was then used for the analysis.

Using Assumption d, the analyst calculated the probability that the breaker would fail to close on demand from the improper termination as follows:

$$P_{(FTS)} = 1 \text{ failure} \div 30 \text{ demands} = 3.3 \times 10^{-2}/\text{demand}$$

Accordingly, the analyst created a change set to adjust the probability of Event CSR-BAD-CLIP to 3.3×10^{-2} per demand.

As stated in Assumption a, the analyst used the SPAR Revision 3.11 to quantify the change in core damage frequency. This model properly accounts for common cause failure probabilities in it's calculated basic event values. The analyst used the unmodified version of the model to calculate that the probability of Event CSR-MDP-CF-STRT was 4.5×10^{-2} given a failure of Pump 2P35A. The analyst then multiplied this value by the probability of Pump 2P35A failing as a result of the performance deficiency. Therefore, the analyst forced the probability of Event CSR-MDP-CF-STRT to be 1.5 x 10^{-3}/ demand. This fully accounts for the probability that the Train B breaker had similar problems.

The analyst then used the modified SPAR to calculate the change in core damage frequency over the exposure period (1 year as stated in Assumption e). The)CDF from internal initiators was 1.52 x 10^{-10} over the exposure period. The analyst noted that using the Phase 2 notebook, and providing a recovery of 3, the result is approximately 6.7 x 10^{-8} assuming a loss of Pump 2P35A. Adjusting for the failure probability of 3.3 x 10^{-2}/demand, the Phase 2 result comes out as approximately 2 x 10^{-9}. Based on the order of magnitude approximation of the Phase 2 process, the analyst determined that this result corroborated the Phase 3 evaluation.

External Events:

The plant-specific SDP worksheets do not currently include initiating events related to fire, flooding, severe weather, seismic, or other external initiating events. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," experience with using the Site Specific Risk-Informed Inspection Notebooks has indicated that accounting for external initiators could result in increasing the risk significance attributed to an inspection finding by as much as one order of magnitude. The analyst determined that an evaluation of external risk would not be required because the result of the Phase 3 indicated that the risk was less than 1 x 10^{-7}. Therefore, an increase in the risk by an order of magnitude would not result in the significance of the finding crossing the 1 x 10^{-6} threshold.

Risk Contribution from Large Early Release Frequency:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst determined that the finding was not significant from a large early release frequency perspective and no further evaluation was necessary because the Phase 3 result provided a risk significance estimation of less than 1 x 10^{-7}.

VI. Licensee's Result:

The licensee performed a preliminary assessment of the condition and concluded that the change in core damage frequency was 2.8×10^{-8}. The analyst evaluated the major differences in assumption as documented in the following table:

Major Analysis Differences				
Assumption	Licensee's Value	Analyst's Value	Difference (percent)	Adjusted)CDF of Analyst's Best Estimate
Best Estimate)CDF	2.8×10^{-8}	1.5×10^{-10}	0.54	N/A
Failure Probability	1.0	3.3×10^{-2}	3.3	3.0×10^{-11}
Operator Failure	3.5×10^{-2}	2.2×10^{-3}	6.3	1.9×10^{-12}
Exposure Time	1017.77 hrs	8760 hrs	861	1.9×10^{-11}
Baseline Model CDF	5.9×10^{-6}	1.5×10^{-5}	254	N/A

The analyst noted that there were four primary reasons for a difference in the licensee's evaluation and the analyst's. These differences are summarized in the table and described here:

< The licensee assumed that the exposure time was 1/2 of the time from the last successful run until the time that the pump was repaired and returned to service. This was 8.61 times smaller than the 1-year exposure time used by the analyst.

< The licensee assumed a failure rate of 1.0 for the pump, indicating that the pump always would have failed the one time that it did. The analyst had used a value 3.3 percent of this, by making the assumption that the probability of failure over the longer exposure period was constant. The first two differences represent a difference in modeling approach. The combined affect of the difference in approach was 28%.

< The licensee calculated the human error probability of operator recovery to be 3.5×10^{-2}. The analyst used the SPAR-H method and determined that the nonrecovery probability was 2.2×10^{-3}. This represented an increase in the failure probability used by the analyst by a factor of 16.

< Finally, the analyst noted that the licensee's baseline core damage frequency was 39 percent of the SPAR baseline. While this cannot be used to obtain a comparable)CDF value, it does show that modeling differences may account for a good portion of the difference in risk calculated.

The analyst noted that both the licensee's and the analyst's results indicated that the finding was of very low risk significance. Additionally, the differences in assumption accounted for most of difference between the two analyses. The remaining difference is expected to be in the modeling differences between the licensee's PRA and the SPAR.

VII. Conclusion:

The performance deficiency resulted in a finding that was of very low risk significance (Green).

VIII. References:

Email: Deese to Pruett, dated 9/14/04

Emails: Lloyd to Loveless, dated 1/24/05 and 1/25/05

INEEL spreadsheet for ANO NUREG-5496 LOOP frequencies and recoveries

NUREG/CR-XXXX (INEEL/EXT-02-01307), "The SPAR-H Human Reliability Analysis Method"

INEEL SPAR-H Human Reliability Assessment worksheets

NRC Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations"

NRC Inspection Manual Chapter 0612, "Power Reactor Inspection Reports"

NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process"

Standardized Plant Analysis Risk Model for Arkansas Nuclear One - Unit 2, Revision 3.11

NUREG-1715, Volume 2, "Component Performance Study - Motor-Driven Pumps, 1987-1998."

Risk-Informed Notebook for Arkansas Nuclear One, Unit 2, Revision 1

IX. Participation:

Lead Inspector:	Rick Deese
Analysts:	David P. Loveless
Peer Reviewer:	Michael Runyan

Performance Deficiency:

The licensee failed to correct lube oil leak on the B emergency diesel generator that, over time, became more severe and threatened the capability of the engine to perform its safety function.

Conclusion:

The finding was of very low significance (Green).