UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

December 7, 1999

C. Randy Hutchinson, Vice President
Operations
Arkansas Nuclear One
Entergy Operations, Inc.
1448 S.R. 333
Russellville, Arkansas 72801-0967

SUBJECT: NRC INSPECTION REPORT 50-313/99-15; 50-368/99-15

Dear Mr. Hutchinson:

This refers to the inspection conducted on October 3 through November 13, 1999, at the Arkansas Nuclear One, Units 1 and 2, facility. The enclosed report presents the results of this inspection.

During the 6-week period covered by this inspection, your conduct of activities at the Arkansas Nuclear One facility was generally characterized by safety-conscious operations, sound engineering and maintenance practices, and careful radiological controls.

The enclosed inspection report also presents the results of our inspection of the Unit 1 Emergency Diesel Generator 2 idler gear stubshaft bracket failure. A Notice of Enforcement Discretion had been granted by the NRC, documented in a July 9, 1999, letter, to extend the allowed outage time specified in Technical Specification 3.7.2.C from 7 to 14 days to complete repair and testing. Based on the results of this inspection, the NRC has determined that three Severity Level IV violations of NRC requirements occurred. These violations are being treated as noncited violations (NCV), consistent with Section VII.B.1.a of the NRC Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the 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, the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Arkansas Nuclear One, Units 1 and 2 facilities.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure(s), and your response, if requested, will be placed in the NRC Public Document Room (PDR).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/s/

P. Harrell, Chief
Project Branch D
Division of Reactor Projects

Docket Nos.: 50-313
50-368
License Nos.: DPR-51
NPF-6

Enclosure:
NRC Inspection Report No.
50-313/99-15; 50-368/99-15

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-313; 50-368
License Nos.:	DPR-51; NPF-6
Report No.:	50-313/99-15, 50-368/99-15
Licensee:	Entergy Operations, Inc.
Facility:	Arkansas Nuclear One, Units 1 and 2
Location:	1448 S. R. 333 Russellville, Arkansas 72801
Dates:	October 3 through November 13, 1999
Inspectors:	R. Bywater, Senior Resident Inspector K. Weaver, Resident Inspector
Approved by:	P. Harrell, Chief, Project Branch D Division of Reactor Projects
Attachment:	Supplemental Information

EXECUTIVE SUMMARY

Arkansas Nuclear One, Units 1 and 2
NRC Inspection Report 50-313/99-15; 50-368/99-15

This routine announced inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

- Unit 1 operators successfully performed the reactor coolant system draindown evolution without error and restricted activities that could have been a distraction while performing the draindown. Unit 1 operators demonstrated good attention to detail, communications, and control while draining the reactor coolant system (Section O1.2).

- Unit 1 operators followed their procedures and successfully performed the reactor startup. The licensed operators demonstrated good reactivity management practices and communication with reactor engineering support personnel (Section O1.3).

- Unit 2 operators demonstrated good communications, peer checking, and control of a plant shutdown and cooldown in preparation for Midcycle Outage 2P99 (Section O1.4).

- Unit 2 operators demonstrated good attention to detail, communications, and control while draining the reactor coolant system and conducting midloop operations (Section O1.5).

Maintenance

- An operator in training, who was manipulating the Turbine-Driven Emergency Feedwater Pump P-7A controls during the quarterly surveillance test, was provided good oversight by a qualified Unit 1 operator, control room supervisor, and operations management personnel. The test was successfully performed without error or equipment malfunction and all test acceptance criteria were met (Section M1.1).

- Unit 1 operations, maintenance, and engineering personnel demonstrated good coordination and communication during the performance of the Unit 1 integrated engineered safeguards test. All equipment functioned as required and no anomalies were identified (Section M1.2).

- Several loose items in close proximity to safety-related equipment in both the Unit 1 and Unit 2 auxiliary buildings were not stored in accordance with the licensee's procedural guidance. Based on these observations, the inspectors concluded that more training was warranted for the licensee's staff in regards to the proper storage of loose items in the vicinity of safety-related equipment. None of the items identified by the inspectors represented an adverse impact on the ability of any system or component to perform its safety function (Section M2.1).

- A degrading trend in Unit 1 Emergency Diesel Generator 2 lube oil pressure existed over a period of at least 4 years. The licensee had identified that a degrading trend existed but did not initiate a condition report for the adverse trend, which would have required a determination of its cause. A violation of Criterion V of 10 CFR Part 50 was identified for the failure to initiate a condition report for a condition adverse to quality in accordance with the licensee's condition report procedure. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 1-1999-186 (Section M2.3).

- The licensee was not implementing the procedural requirements of its emergency diesel generator reliability monitoring program. The inspectors concluded that if the reports required by the emergency diesel generator reliability monitoring program had been completed and reviewed by plant management, an additional opportunity for identification of the degrading Unit 1 Emergency Diesel Generator 2 lube oil pressure trend would have existed and may have resulted in correcting the condition prior to failure. A violation of Criterion V of 10 CFR Part 50 was identified for the failure to follow the procedural requirements of the emergency diesel generator reliability monitoring program. This Severity Level IV violation is being treated as a noncited violation in accordance with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR C-1999-217 (Section M3.2).

- Unit 1 Emergency Diesel Generator 2 was operated outside the limits of the emergency diesel generator operating procedure on July 1, 1999, a condition prohibited by the licensee's Conduct of Operations procedure. This is a violation of Criterion V of 10 CFR Part 50. This Severity Level IV violation is being treated as a noncited violation in accordance with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 1-1999-178 (Section M4.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period shutdown in Refueling Outage 1R15. On October 9, 1999, Unit 1 operators made the reactor critical and on October 10, the plant entered power operation mode at 2 percent power. Unit 1 achieved 100 percent power on October 13. On November 5, Unit 1 operators removed the unit from service and placed the reactor in hot standby mode for replacement of the main turbine trip oil system diaphragms and to repair an oil leak on the Reactor Coolant Pump (RCP) P-32D upper oil reservoir. On November 6, following the maintenance activities, Unit 1 operators placed the unit back in service and completed escalation to 100 percent power on November 7. Unit 1 remained at 100 percent power for this remainder of the inspection period.

Unit 2 began this inspection period at 100 percent power. On November 5, Unit 2 operators reduced reactor power to approximately 54 percent because of grid limitations. On November 6, Unit 2 operators commenced a plant shutdown from 54 percent power in preparation for the Unit 2 Midcycle Outage 2P99. On November 7, Unit 2 operators manually tripped the reactor and entered Midcycle Outage 2P99. At the end of this inspection period, Unit 2 remained shutdown for Midcycle Outage 2P99.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors observed various aspects of plant operations, including shift manning, to verify compliance with Technical Specifications (TS), plant procedures, and the Updated Safety Analysis Report. The inspectors also observed the effectiveness of communications, management oversight, proper system configuration and configuration control, housekeeping, and operator performance during routine plant operations and surveillance testing.

The conduct of operations was professional. Evolutions were generally well controlled and performed according to procedures. Shift turnover briefs were comprehensive. Housekeeping was generally good and discrepancies were promptly corrected. Safety systems were found properly aligned. Specific events and noteworthy observations are detailed below.

O1.2 Unit 1 - Draindown to Reduced Inventory to Remove Steam Generator Nozzle Dams

a. Inspection Scope (71707)

On October 1, 1999, Unit 1 operators drained the reactor coolant system (RCS) and established reduced inventory conditions to allow for steam generator nozzle dam removal at the conclusion of steam generator maintenance. The draining of the RCS was conducted in accordance with Procedure 1103.011, “Draining and N2 Blanketing the RCS,” Revision 25. The inspectors observed draining operations and the licensee’s controls of this activity.

b. Observations and Findings

The inspectors observed that Unit 1 operators followed the procedure and successfully performed the draindown of the RCS without error. The inspectors observed that the shift superintendent prohibited the performance of other unrelated plant activities that could cause control room alarms and interfere with the ability of the operators to focus attention on the RCS draindown. Unit 1 operators demonstrated good attention to detail, communications, and control while draining the RCS.

c. Conclusions

Unit 1 operators successfully performed the RCS draindown evolution without error and restricted activities that could have been a distraction while performing the draindown. Unit 1 operators demonstrated good attention to detail, communications, and control while draining the RCS.

O1.3 Unit 1 - Startup Activities Following Completion of Refueling Outage 1R15

a. Inspection Scope (71707)

On October 9, 1999, Unit 1 operators performed a reactor startup in accordance with Procedures 1102.008, “Approach to Criticality,” Revision 17, and 1102.002, “Plant Startup,” Revision 66. The inspectors observed the operators make the reactor critical and place the turbine generator online, which ended Refueling Outage 1R15.

b. Observations and Findings

The inspectors observed that Unit 1 operators followed procedures and successfully performed the reactor startup. The operators properly responded to an asymmetric rod alarm when Rod 7 in Group 6 indicated approximately 6 percent deviation from its group demand. Rod control was placed in manual and its position was restored to maintain rod alignment TS limits. The inspectors observed good reactivity management practices by the licensed operators and communication with reactor engineering support personnel during the approach to criticality.

c. Conclusions

Unit 1 operators followed their procedures and successfully performed the reactor startup. The licensed operators demonstrated good reactivity management practices and communication with reactor engineering support personnel.

O1.4 Unit 1 - Plant Shutdown to Replace Main Turbine Trip Oil System Diaphragms and Repair RCP P-32D Upper Oil Reservoir Leak

On November 5, 1999, the licensee determined that similar substandard material was present in the Unit 1 main turbine trip oil system diaphragms that had caused a turbine trip/reactor trip at another facility and a forced shutdown at another. The licensee decided to take the turbine generator offline to replace the substandard material before failure resulted in a loss of oil pressure and turbine trip. Unit 1 operators removed the unit from service on November 5 and maintained the reactor critical in hot standby mode while the main turbine trip oil system diaphragms were replaced on November 6. While the reactor was in hot standby mode, maintenance personnel also repaired an oil leak on the RCP P-32D upper oil reservoir piping. There was no evidence of RCP lube oil leakage that had not been collected by the RCP lube oil collection system.

O1.4 Unit 2 - Plant Shutdown and Cooldown in Preparation for Midcycle Outage 2P99

a. Inspection Scope (71707)

On November 7, 1999, the inspectors observed portions of the Unit 2 plant cooldown in accordance with Procedure 2102.010, “Plant Cooldown,” Revision 32.

b. Observations and Findings

The inspectors observed that operators demonstrated good communications and control of the evolutions. The plant cooldown was performed well and in accordance with procedures. The inspectors noted that the Unit 2 operators promptly responded to all control room panel alarms and took appropriate actions. The inspectors also noted that three-part communication and peer checking were consistently applied during the evolution.

c. Conclusions

Unit 2 operators demonstrated good communications, peer checking, and control of a plant shutdown and cooldown in preparation for Midcycle Outage 2P99.

O1.5 Unit 2 - Draindown of the RCS to Midloop Operations

a. Inspection Scope (71707)

The inspectors reviewed the licensee’s preparations for draining the RCS and operating in reduced inventory, attended the prejob briefing, and subsequently observed the Unit 2 operators preform the draindown of the RCS to midloop condition to allow for steam generator tube inspections.

On November 9, 1999, the inspectors observed Unit 2 operators performed the prejob briefing for draining of the RCS to establish midloop conditions for steam generator tube inspections. The prejob briefing was thorough and included discussions of individual assignments, command and control of the activity, communications, limits and precautions, potential problems, termination criteria, and lessons learned.

b. Observations and Findings

On November 10, the inspectors observed the Unit 2 operators perform the RCS draindown in accordance with Procedure 2103.011, “Draining the Reactor Coolant System,” Revision 25. During the evolution, Unit 2 operators secured the draindown in accordance with the procedure at predetermined levels to ensure the various RCS level indications were consistent. On one occasion, the Unit 2 operators secured the draindown briefly due to loss of communication with the operator stationed locally at the RCS tygon tube level indication. The inspectors observed that the control room noise levels and personnel entry were kept to a minimum.

c. Conclusions

Unit 2 operators demonstrated good attention to detail, communications, and control while draining the RCS and conducting midloop operations.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Unit 1 - Steam Driven Emergency Feedwater (EFW) Pump P-7A Quarterly Test

a. Inspection Scope (61726)

The inspectors observed Unit 1 operators perform Procedure 1106.006, “Emergency Feedwater Pump Operation,” Supplement 12, “Steam Driven Emergency Feedwater Pump (P-7A) Quarterly Test,” Revision 59.

b. Observations and Findings

On October 26, 1999, the inspectors observed Unit 1 operators perform the EFW Pump P-7A quarterly test. The inspectors observed that one of the two operators performing this test was receiving on-the-job training for manipulation of the EFW system. The inspector noted that this operator received good oversight by the qualified operator in charge as well as oversight by the control room supervisor and operations management present in the control room. The test was successfully performed without error or equipment malfunction and all test acceptance criteria were met.

c. Conclusions

An operator in training, who was manipulating the EFW Pump P-7A controls during the quarterly surveillance test, was provided good oversight by a qualified Unit 1 operator, control room supervisor, and operations management personnel. The test was successfully performed without error or equipment malfunction and all test acceptance criteria were met.

M1.2 Unit 1 - Integrated Engineered Safeguards (ES) System Test

a. Inspection Scope (61726)

On October 3, 1999, the inspectors observed the licensee perform Procedure 1305.006, “Integrated ES System Test,” Revision 18.

b. Observations and Findings

The inspectors observed that the performance of this complex test, involving maintenance, engineering, and operations personnel, was well coordinated and controlled. A Unit 1 operator was assigned as test coordinator to prepare and coordinate the test activities. The inspectors observed that personnel involved demonstrated good communication and peer checking techniques. All equipment functioned, as expected.

c. Conclusions

Unit 1 operations, maintenance, and engineering personnel demonstrated good coordination and communication during the performance of the Unit 1 integrated ES test. All equipment functioned as required and no anomalies were identified.

M1.3 Unit 1 - Emergency Diesel Generator (EDG) 2 Lube Oil Pressure Degradation (71707, 62707, 61726, 37551)

The Unit 1 standby emergency power system includes two EDGs. Each EDG uses a 20-cylinder, 900 rpm, Model 20-645-E4 engine manufactured by the Electro-Motive Division (EMD) of General Motors Corporation. TS 4.6.1.3 requires that each EDG be removed from service every 18 months for a maintenance and inspection outage. TS 3.7.2.C allows continued operation with an EDG inoperable for up to 7 days.

The engine lubrication system for the EDGs consists of three separate subsystems: main lubricating, piston lubricating, and scavenging oil systems. An adequate supply of oil is essential for lubrication of engine components. The EDG vendor Technical Manual TM S407.0010, “Technical Manual for Emergency Diesel Engines and Associated Equipment,” identified that the minimum oil pressure was approximately 8-12 psig at idle and 25-29 psig at full speed and that the alarm or shutdown pressures were determined by system application to suit the installation. At ANO Unit 1, the low lube oil pressure alarm setpoint was 26 psig and the low lube oil pressure trip setpoint was 17 psig.

A degrading trend in EDG 2 lube oil pressure had existed for approximately 4 years. An historical review of EDG 2 data collected, during monthly surveillance testing from 1995 to the present, indicated that lube oil pressure had degraded steadily from approximately 90 psig in January 1995 to 72 psig in January 1998. The rate of pressure degradation then increased until April 1998, stabilizing at approximately 53 psig. In January 1999, pressure began to slowly trend downward until it reached approximately 45 psig in June 1999.

EDG 2 operating performance data was recorded during surveillance testing in Operations Logsheet OPS-A15b, “DG2 Logsheet.” Included in the list of parameters to be recorded was EDG lube oil manifold pressure. The logsheet identified that the maximum value was 125 psig, the minimum value was 26 psig, and the normal range was 80-90 psig.

An 18-month maintenance and inspection outage for EDG 2 was performed in

February 1998. Although maintenance tasks were included to repair some routine minor lube oil leaks, the outage scope did not include work to identify and improve the reasons for the degraded lube oil system pressure.

An operations department shift engineer identified a degrading lube oil pressure trend while performing Procedure 1015.006, “Operations Equipment Trending Program,” Revision 5, on March 25, 1998. The shift engineer documented in the trend report that the condition existed and should be evaluated by system engineering to determine if repair or replacement of the lube oil pump was required.

Unit 1 was shutdown for Refueling Outage 1R14 during April and May 1998. During the 24-hour endurance run for EDG 2, performed on April 18, 1998, operations personnel recorded that lube oil pressure degraded from 64 psig at the beginning of the test to 59 psig when the test was completed. In response to the observed degradation of EDG 2 lube oil pressure, the EDG system engineer initiated Job Request (JR) 932190 and Job Order (JO) 978188, on May 1, 1998, to check for leaks on the suction side of the main lube oil pump. The EDG system engineer also initiated JR 932191 and JO 978190 on May 1, 1998, to repair or replace the lube oil pressure relief valve if the previous efforts were unsuccessful in correcting the lube oil pressure degradation. The engineer documented in JR 932191, a recommendation that maintenance be performed prior to plant heatup from the refueling outage to avoid entering a TS limiting condition of operation action statement when the maintenance was performed. However, the engineer concluded that the degraded lube oil pressure did not result in EDG 2 being inoperable. Based on the conclusion that EDG 2 was operable with the degraded lube oil condition, the licensee scheduled the maintenance to be performed during the June 1999 EDG 2 maintenance and inspection outage. A condition report (CR) was not initiated for the degraded lube oil condition.

On June 28, 1999, the licensee removed EDG 2 from standby service to perform the scheduled 18-month periodic maintenance inspection required by TS 4.6.1.3. The maintenance was performed using Procedure 1402.066, “18 Month Inspection on Unit One Emergency Diesel Generator Engine,” Revision 15. Postmaintenance testing was performed using Procedure 1104.036, “Emergency Diesel Generator Operation,” Revisions 38-01, 38-02, and 38-03.

The lube oil pump suction piping seals and the lube oil pressure relief valve were replaced during the maintenance and inspection outage. The EDG vendor manual identified that the relief valve setting allowed a maximum oil pressure of about 125 psig under cold oil conditions and allowed an adequate pressure for normal operation under hot oil conditions. During informal testing of the relief valve removed from EDG 2, the licensee identified that its setpoint had drifted lower. The relief valve began to open at a lower pressure in comparison to a new valve. The licensee planned to develop a formal test to quantify the pressure relieving characteristics of the replaced valve.

Postmaintenance testing of the EDG included slow idle (400 rpm) and overspeed trip tests. During performance of the slow idle engine start and inspection on June 30, the control room received an alarm indicating EDG 2 had tripped. An auxiliary operator was dispatched to the EDG 2 room to investigate and found that the engine was still running. When notified by the auxiliary operator of the control room alarm, the reactor operator overseeing the test in the engine room observed that the low lube oil pressure trip annunciator was in alarm on the local alarm panel. An auxiliary operator trainee, who was controlling engine speed with the fuel rack lever, identified that the force required to be applied on the lever to maintain engine speed at 400 rpm had reversed. The reactor operator and maintenance personnel observed that lube oil pressure was approximately 60 psig.

Maintenance personnel informed the reactor operator that they did not require much additional time to complete their inspections. Therefore, since oil pressure appeared adequate and the inspection was nearly finished, the reactor operator allowed engine operation to continue. When the inspection was completed and the auxiliary operator trainee released the fuel rack lever, the governor automatically shut the engine down. The cause of the low lube oil pressure trip was attributed to a momentary low pressure condition below the 17 psig low lube oil pressure trip setpoint. The licensee determined that this occurred while the auxiliary operator trainee was attempting to control the engine fuel rack lever to achieve and maintain 400 rpm engine speed. CR 1-1999-0176 was initiated to document the EDG 2 trip. Based on additional EDG 2 testing and evaluation by engineering personnel, the licensee concluded that the continued operation of the engine while in a tripped condition did not affect operability of the governor.

The EDG 2 postmaintenance operability verification run was started on July 1. Lube oil pressure was observed to be approximately 75 psig soon after the engine was started, but began to degrade. When lube oil pressure had degraded to 33 psig, control room operations personnel determined that EDG performance was not acceptable to prove operability and unloaded the generator. Inspection and data gathering continued during unloaded engine conditions by operations and system engineering personnel to determine the cause of the pressure degradation. Procedure 1104.036 specified that a cooldown period of 17 minutes of unloaded operation be performed before stopping the engine. The operators were aware of the 26 psig alarm setpoint and the minimum pressure allowed by the logsheet and decided that the EDG would be stopped if oil pressure decreased to 30 psig. However, during review of Procedure 1104.036, operators noted that there was a 35 psig minimum lube oil pressure limit in the Limits and Precautions section of the procedure. After approximately 5 minutes, lube oil pressure dropped to 29 psig and the engine was stopped. CR 1-1999-178 was initiated to document and evaluate the EDG 2 shutdown. The licensee also completed Engineering Request 991816 to revise the Procedure 1104.036 limit from 35 to 26 psig to make the limit consistent with the low lube oil pressure alarm setpoint, vendor manual, and the Unit 1 Safety Analysis Report. The system engineer informed the inspectors that the 35 psig procedure limit was intended to be a conservative value above the 26 psig low pressure alarm setpoint.

The licensee initiated an investigation to determine the cause of the EDG 2 low lube oil pressure condition and steps necessary to restore operability. During this investigation, two bolt heads were found in the engine oil sump at the gear train end of the engine. During further engine disassembly, maintenance and engineering personnel identified that two of the five bolts holding the idler gear stubshaft bracket assembly to the engine had failed. It was also noted that the rest of the bolts were loose. Uneven wear patterns were noted on all gears in the gear train. Additionally, the idler gear stubshaft bracket was cracked between the Idler Gears 1 and 2.

The licensee developed a schedule for the repair and postmaintenance testing activities and determined that they would require additional time beyond what remained in the 7-day allowed outage time for EDG 2. The licensee initiated discussions with the NRC to request a Notice of Enforcement Discretion (NOED) and extension of the allowed outage time from 7 to 14 days. Without an extension, initiation of a plant shutdown would have been required on July 5. The NRC verbally granted an NOED from the requirements of TS 3.7.2.C on July 5. The licensee's formal written request was provided to the NRC on July 6 and the NRC's formal written reply granting approval was provided on July 7.

Significant maintenance that was performed to correct the degrading lube oil pressure included the following:

- The idler gear stubshaft bracket was replaced with a bracket with improved engine bolting and lube oil distribution channels,

- The turbocharger was replaced with a high capacity model better suited for low load engine operation, and

- The entire gear train was replaced.

Following postmaintenance testing, including a 24-hour endurance run, EDG 2 was returned to an operable status on July 8. Lube oil pressure during engine operation was stable at approximately 82 psig.

The licensee initiated CR 1-1999-186, on July 7, to perform a programmatic review of the EDG 2 failure to determine why corrective actions were not initiated earlier in response to the degraded lube oil condition and why they were ineffective at preventing the EDG 2 failure.

The licensee believed that the initial lube oil pressure degradation observed prior to Refueling Outage 1R14 was most likely attributable to a degrading pressure relief valve. Subsequent step changes in pressure may have resulted from fatigue failure of stubshaft bracket fasteners. Finally, after the pressure relief valve was replaced during June 1999, additional hydraulic pressure was applied to the backside of the stubshaft bracket, which may have overloaded the remaining bolt, causing brittle fracture of the bolt and bracket.

The licensee evaluated EDG 2 operability prior to the test failure, on July 1, 1999, and concluded that the ability of EDG 2 to have operated for a 30-day mission time was indeterminate. Inspections of the bolts that had failed due to fatigue indicated that the initiating condition had existed for an extended period of time. However, the licensee noted that EDG 2 had completed many successful surveillance tests, including 24-hour endurance runs while in this condition. Section 8.3.1.1.7.1 of the Updated Safety Analysis Report identified that the postulated loading of the Unit 1 EDGs during a design basis accident was 2750 kW and that the required mission time was 30 days (720 hours).

The inspectors performed an independent review of the licensee's conclusion regarding the capability of EDG 2 to meet its mission time. The inspectors concluded that sufficient data of the appropriate type was not available to establish when EDG 2 could not perform its intended safety function. Therefore, the inspectors determined that the point in time could not be reasonably established.

M1.4 Unit 1 - EDG 2 Maintenance and Testing - General Comments (62707, 61726)

The inspectors observed portions of the EDG 2 maintenance outage and postmaintenance testing performed in accordance with Procedures 1402.066 and 1104.036. The inspectors also observed portions of JO 978190, as amended, following identification of the stubshaft bracket failure. The inspectors observed that the maintenance technicians were knowledgeable of the equipment, performed the activities using approved procedures, and worked well with the vendor representative who was onsite providing technical assistance. Housekeeping practices, foreign material exclusion (FME) controls, and fire protection program requirements during the maintenance were effectively implemented. The inspectors verified that the compensatory actions required by the NOED were also effectively implemented.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Storage of Loose Items in the Units 1 and 2 Auxiliary Buildings

a. Inspection Scope (62707, 71707)

The inspectors conducted tours of the Unit 1 auxiliary building following completion of Unit 1 Refueling Outage 1R15 to ensure that all scaffolding, tools, and equipment used during the refueling outage were removed or properly secured away from safety-related equipment.

b. Observations and Findings

During one tour on October 28, 1999, the inspectors identified two compressed gas cylinders tied off with a rope to safety-related conduit in the Unit 1 upper north piping penetration room. The inspectors were concerned that the gas cylinders presented the potential for missiles and adverse impact on the conduits as well as the other safety-related equipment in the room (e.g., EFW, high pressure injection, low pressure injection, and reactor building spray system piping and reactor building penetrations) during a seismic event. The inspectors notified Unit 1 operators and the compressed gas cylinders were promptly removed by the responsible maintenance craft. Unit 1 operators initiated CR 1-1999-0516 to require engineering personnel to evaluate the impact from the gas cylinders on the safety-related equipment during a seismic event. The licensee determined that there would be no adverse impact on the associated safety-related conduit or equipment based on the engineering evaluation and the fact that the cylinders were secured with their protective caps.

The inspectors reviewed Procedure 1000.047, "Control of Combustibles," Revision 14, which provided the requirements for storage of compressed gas cylinders. The inspectors noted that the procedure stated that compressed gas cylinders shall be secured by chains while in use and/or in storage. Procedure 1000.047 further stated that wire, tie wraps, and rope is not an acceptable means of securing gas cylinders. The inspectors were concerned that this procedure was silent with no requirements for proper storage of compressed gas cylinders in and around safety-related equipment.

The inspectors also reviewed Procedure 1000.024, “Control of Maintenance,” Revision 46, which provided guidelines for storage of equipment in the plant. The procedure provided guidance that job boxes or tool boxes should be a minimum of 2 feet from safety-related equipment and any items which have a height greater than 2 feet should be placed at a distance from safety-related components equal to their height plus 6 inches. In addition, the procedure provided guidance that items should not be tied to existing safety-related components without a review by operations and/or engineering personnel.

The inspectors determined, based on review of Procedures 1000.024 and 1000.047, that the maintenance craft involved did not properly secure the compressed gas cyclinders in accordance with the guidance in these procedures.

The inspectors identified several loose items stored in both Units 1 and 2 auxiliary buildings that did not meet the guidelines provided in Procedure 1000.024. The inspectors notified Units 1 and 2 control room personnel and the operators initiated CRs 2-1999-0656 and 1-1999-0521. Based on the licensee’s evaluation, no adverse impact on any safety-related equipment existed from the identified loose items. However, operations personnel removed several of the items and properly secured the remaining items. The inspectors discussed with licensee management that it was apparent, based on these observations, that additional training was warranted for staff in the proper storage of loose items in and around safety-related equipment to ensure that no adverse impact would occur during a seismic event.

c. Conclusions

Several loose items in close proximity to safety-related equipment in both the Units 1 and 2 auxiliary buildings were not stored in accordance with the licensee’s procedural guidance. Based on these observations, the inspectors concluded that more training was warranted for the licensee’s staff in regards to the proper storage of loose items in the vicinity of safety-related equipment. None of the items identified by the inspectors represented an adverse impact on the ability of any system or component to perform its safety function.

M2.2 Idler Gear Stubshaft Bracket Assembly Upgrade and EDG 2 Bracket Failure

a. Inspection Scope

The inspectors reviewed information in the vendor technical manual regarding upgrade of the EDG idler gear stubshaft bracket assembly and the history of the licensee’s plans to implement this upgrade. The inspectors also reviewed the licensee’s evaluation of the EDG 2 idler gear stubshaft bracket assembly failure.

b. Observations and Findings

The idler gear stubshaft bracket assembly provided the attachment point for the Idler Gears 1 and 2, which transmitted power from the engine crankshaft gear to the turbocharger and camshafts. EDG 2 was built by EMD prior to 1972, and according to the vendor technical manual, all EMD Model 645 turbocharged engines manufactured prior to 1972, were provided with stubshaft bracket (Part 8288760). This bracket design used 15 bolts without washers to attach the bracket to the engine crankcase. This bracket design also consisted of a thrust plate that bolted on to the Idler Gear 1 stubshaft.

In 1972, EMD revised the design of the stubshaft bracket assembly (Part 8442661) by adding hardened washers to the bracket mounting bolts and increasing the bolt length 1/4 inch. Also, the thrust plate was redesigned with mounting bolts that were fastened through the stubshaft into the crankcase.

In 1974, EMD again revised the design of the stubshaft bracket assembly (Part 8470154). The new bracket design incorporated the same improvements as the previous design, but added three additional bolts to fasten the bracket to the crankcase and included modified oil passages in the bracket to provide a supply of filtered lube oil from the turbocharger filter to the Idler Gear 1 stubshaft.

The vendor provided information to industrial users regarding idler gear stubshaft bracket design changes in an information transmittal document, called a Power Pointer, dated May 23, 1972, and Maintenance Instruction Modernization Recommendation 9587, dated January 1976. The licensee’s current revision of the vendor manual did not contain the 1972 Power Pointer. Maintenance Instruction 9587 was not added to the vendor manual until 1991. Additional discussion regarding the vendor manual is included in Section M3.1 of this report. The inspectors considered the licensee’s failure to incorporate early vendor information into the vendor manual to be a significant weakness.

Information regarding a bracket upgrade was provided specifically to the licensee in EMD Proposal 84744, dated July 31, 1984. The information provided did not indicate that the idler gear stubshaft bracket assembly must be replaced immediately. The 1972 Power Pointer recommended that idler gear bracket (Part 8442661) be installed whenever replacement of idler gears was necessary because the replacement bracket was re-designed to provide increased strength. The Power Pointer did not identify a history or potential for bracket failure. Maintenance Instruction 9587 and Proposal 84744 recommended that idler gear bracket (Part 8470154) be installed to upgrade the design of the idler gear stubshaft assembly and gears to current design for improved strength and reliability. These documents did not identify a history or potential for bracket failure either.

The licensee evaluated Proposal 84744 as part of Plant Engineering Action Request 84-3062, on December 12, 1984. Plant Engineering Action Request 84-3062 was initiated to replace the turbocharger on EDG 1 after it had failed in 1984. The replacement turbocharger was a high capacity turbocharger, better suited for low load engine operation. The idler gear stubshaft bracket assembly upgrade was included in the turbocharger replacement modification. The failure resulted in damage to gears in the gear train and their removal allowed access to the bracket at that time.

In 1982, the EDG 2 turbocharger also failed and it was replaced with a like-for-like 18:1 gear ratio turbocharger. The inspectors asked the licensee why the idler gear stubshaft bracket assembly and turbocharger were not upgraded at that time. The licensee informed the inspectors that, although there had been no formal evaluation documented, the EDG 2 gear train was inspected and no damage or unusual wear was identified. Damage would have required removal of the gears and allow access to the bracket. The turbocharger was not upgraded to the high capacity design because the licensee did not believe that a significant number of low load engine operation hours would be accumulated to warrant upgrade to the high capacity turbocharger. The inspectors noted that the 1982 EDG 2 turbocharger failure occurred prior to the licensee receiving the 1972 Power Pointer, Maintenance Instruction 9587, or Proposal 84744.

The licensee informed the inspectors that there had been no apparent urgency to upgrade the idler gear stubshaft bracket assembly to the current design. The vendor modernization recommendation was viewed as an engine enhancement and not required for operability. Therefore, the licensee deferred upgrading the EDG 2 bracket assembly until replacement of the turbocharger, which was planned to be performed in 2001.

The inspectors did not identify any additional vendor or operating experience information that should have caused an increase in priority for completion of the upgrade. A vendor representative informed the licensee that no bracket failures were known to have occurred in the nuclear industry and there had not been a 10 CFR Part 21 notification regarding this component. The vendor representative did identify that there had been a few failures in nonnuclear applications of the engine. EMD engines in nonnuclear applications generally operated for much longer periods of time and with a different load profile than engines at a nuclear facility. This made a direct correlation between nonnuclear and nuclear engine applications difficult.

The licensee's root cause determination identified that the failure of the bracket occurred as a result of fatigue failure of bolting caused by a loss of bolt preload. The loss of preload was caused either by improper bolt torque applied during original installation or bracket design issues (the absence of hardened washers and additional bolting in the original design) that resulted in loss of preload through engine operation stresses.

M2.3 EDG 2 Lube Oil Pressure Monitoring and Trending

a. Inspection Scope (71707, 61726, 37551)

The inspectors reviewed the method of monitoring performance of the Unit 1 EDGs during surveillance testing. This included reviewing how abnormal values of EDG operating parameters were addressed during consideration of EDG operability and how adverse trends in parameters were identified.

b. Observations and Findings

Procedure 1104.036 required that operations personnel record several EDG 2 operating parameters during engine operation on Logsheet OPS-A15b. Among these operating parameters was EDG 2 lube oil manifold pressure. Logsheet OPS-A15b identified values called MAX, MIN, and NORMAL. The MAX value was 125 psig, the MIN value was 26 psig, and the NORMAL range was 80-90 psig. Procedure 1015.003A, “Unit 1 Operations Logs,” Revision 44-05, required that if a value recorded in a log exceeded a MAX or MIN value, then the operator recording the data was to initiate corrective action and notify the control room. If a value was outside of the NORMAL range, Procedure 1015.003A required no action because the NORMAL range was only the typical range. Logsheet OPS-A15b also required that the control room supervisor or shift superintendent be informed immediately of any parameter outside a limiting range or any abnormal trend development and that a CR should be submitted for any condition affecting EDG operability.

As discussed earlier, EDG 2 lube oil pressure had been trending downward over a period of over 4 years. The licensee informed the inspectors that the NORMAL ranges were developed over time by monitoring performance of a component during its operation and generally were not based on a technical evaluation. The inspectors asked the system engineer what was the operating range for lube oil pressure recommended by the vendor. The engineer informed the inspectors that it was 60-90 psig. The inspectors asked the licensee why a degrading lube oil pressure, outside of the normal range, had been tolerated for such a long time. The answer was that the minimum value for operability was 26 psig and that the degrading trend in lube oil pressure, although recognized and identified, was not determined to be an operability concern.

A degrading trend in EDG 2 lube oil pressure had been identified during performance of Procedure 1015.006, “Operations Equipment Trending Program,” Revision 5. The operations shift engineer was required to review EDG operating parameters (including lube oil pressure) for trends on a quarterly basis and initiate corrective action based on review of the trends. Procedure 1015.006 stated that corrective actions included, but were not limited to: initiating a JR, engineering request, reanalysis of inservice testing program ranges, expansion of the trending program to additional parameters, change in operating practice, or change in test frequency. On August 14, 1996, the shift engineer documented that EDG 2 lube oil pressure: appeared to be slowly trending down. System engineering needs to assess if this is a problem. If not, the acceptable normal range needs to be changed. On March 25, 1998, the shift engineer documented that: manifold lube oil and turbo-bearing oil pressure have been steadily decreasing over the last cycle and appears to be degrading. System engineering should evaluate pump replacement or repair. A corrective action document was not initiated in either of these cases.

The licensee stated that discussions occurred between operations and engineering personnel regarding the EDG 2 degrading lube oil pressure condition. The licensee also stated that the vendor had been contacted and possible causes for the pressure degradation were identified. These discussions resulted in the initiation of the maintenance documents discussed above and the system engineer informally established a 40 psig threshold, at which additional unspecified actions would be taken.

There was no corrective action program documentation of these activities.

Procedure 1000.104 defined a potential adverse trend report as a CR that documents a trend identified by assessment monitoring that suggests an undesired value, potential adverse trend, questionable performance, or similar measure relative to site or industry standards. The degrading trend in EDG 2 lube oil pressure identified by the shift engineer on August 14, 1996, and March 25, 1998, was a trend adverse to safety. The failure to initiate a CR upon identification of a trend adverse to safety was contrary to the requirements of Procedure 1000.104. Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by documented instructions and shall be accomplished in accordance with the instructions. The failure to initiate a CR, in accordance with Procedure 1015.006, for the degrading EDG 2 lube oil pressure condition on August 14, 1996, and March 25, 1998, is a violation of Criterion V. This Severity Level IV violation is being treated as a noncited violation (50-313/9915-01), consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 1-1999-186.

c. Conclusions

A degrading trend in EDG 2 lube oil pressure existed over a period of at least 4 years. The licensee had identified that a degrading trend existed but did not initiate a CR for the adverse trend, which would have required a determination of its cause. A violation of Criterion V was identified for the failure to initiate a CR for a condition adverse to quality in accordance with Procedure 1015.006. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 1-1999-186.

M3 Maintenance Procedures and Documentation

M3.1 EMD Vendor Manual Review

a. Inspection Scope (62707, 37551)

The inspectors reviewed Technical Manual TM S407.0010; Procedure 5510.203, "Vendor Technical Manual Review and Update," Revision 1; Engineering Request 991865E101, "Review of EMD vendor Maintenance Instructions and Power Pointers for ANO-1 Emergency Diesel Generators," Revision 0. The inspectors also interviewed licensee personnel. The purpose of this review was to determine if the EDG vendor manual was being updated regularly, whether information received from the vendor was appropriately reviewed for applicability, and if modifications were implemented when necessary.

b. Observations and Findings

Technical Manual TM S407.0010 was an assembly of many individual documents, including an operating manual, maintenance manual, maintenance instructions, Power Pointers, subcomponent instructions, an EMD Owner's Group recommended maintenance program document, and others. The inspectors identified a few minor editorial errors in the assembly of Technical Manual TM S407.0010 and provided these to the licensee's technical manual group leader.

The technical manual group leader informed the inspectors that Technical Manual TM S407.0010 did not exist until 1987. During the early years of its existence, many revisions were made to the vendor manual as historical information, was identified as missing, or was received from the vendor, and then it was incorporated into the vendor manual. Maintenance Instruction Modernization Recommendation 9587 was incorporated into Technical Manual TM S407.0010 in Revision 11, on November 11, 1991, when a collection of previously issued updates was provided by the vendor. The licensee reviewed the maintenance instruction, and as discussed previously, the idler gear stubshaft bracket assembly upgrade had already been implemented on EDG 1 and the licensee determined that it was an enhancement to EDG reliability and not required for operability.

The licensee's event investigation team and a vendor representative reviewed Technical Manual TM S407.0010 and determined that there were 26 Maintenance Instructions and Power Pointer documents that had been issued, but were not included in the vendor manual. Corrective actions were initiated, as part of CR 1-1999-178, to review the vendor information receiving and review process to correct deficiencies in the vendor manual update process. The inspectors considered that a weakness had existed in this process because a significant number of vendor documents had not been included in the vendor manual. The licensee initiated corrective actions, as part of CR 1-1999-178, to evaluate the generic implications of this occurrence with respect to the receipt, review, and implementation process for vendor and owner's group information.

The licensee obtained the missing documents and reviewed them for applicability. The licensee also reviewed these documents and all other maintenance instructions and Power Pointers to ensure that they had adequately evaluated for implementation (modifications, periodic maintenance, surveillance testing, etc.). The licensee documented this evaluation in Engineering Request 991865E101 and concluded that there were no operability concerns from the vendor manual review. Two issues requiring additional followup were identified involving the potential for EDG exhaust baffles to become loose and a susceptibility for soldered joints in lube oil coolers to leak over time. Corrective actions were initiated, as part of CR 1-1999-178, to review each of these issues. The inspectors reviewed Engineering Request 991865E101 and concluded the licensee's actions to evaluate the vendor information for applicability and operability of the EDGs were acceptable. The inspectors concluded that the items identified during the licensee's evaluation did not present an EDG operability concern.

c. Conclusions

A weakness was identified in the licensee's vendor information receiving and review process. The licensee's evaluation of the missing information and all other applicable vendor information regarding EDG operability was acceptable. No EDG operability concerns were identified.

M3.2 EDG Reliability Program and Station Blackout Rule

a. Inspection Scope (61726, 37551)

The inspectors reviewed Procedures 1032.034, “ANO Unit 1 EDG Reliability Program,” Revision 0; 1032.033, “Unit 2 Emergency Diesel Generator Reliability Program,” Revision 2; and the licensee’s April 15, 1991, response to the Station Blackout Rule (10 CFR 50.63) to determine if the licensee was implementing its NRC commitments for monitoring EDG reliability.

b. Observations and Findings

In an April 15, 1991, letter to the NRC, the licensee committed to implement an EDG reliability program that would, at a minimum, meet the guidelines of Regulatory Guide 1.155, “Station Blackout,” and implement a target reliability goal of 0.95. Regulatory Guide 1.155 stated that some of the attributes in an EDG reliability program would include: (1) surveillance testing and reliability monitoring programs designed to track EDG performance and to support maintenance activities, (2) a maintenance program that ensures that the target EDG reliability is being achieved and provides a capability for failure analysis and root cause investigations, (3) an information and data collection system that services the elements of the reliability program and monitors achieved EDG reliability levels against target values, (4) identified responsibilities for the major program elements, and (5) a management oversight program for reviewing reliability levels being achieved and ensuring that the program is functioning properly.

Procedure 1032.034 stated that the intent of the procedure was to define the EDG reliability program for Unit 1. The procedure identified that performance monitoring of important parameters was to be completed on an ongoing basis to obtain information of the condition of the EDG and key components. This was to be accomplished to identify precursor conditions that would indicate possible failures. One of the parameters required for monitoring and trending was EDG lube oil pressure. The normal range for this parameter was identified as 75-85 psig and the minimum value was specified as 86 psig. The inspectors considered this a typographical error because the minimum pressure was greater than the lower limit of the normal range. In comparison, turbocharger bearing header pressure was also a trended parameter in the procedure and its minimum value was identified as 26 psig, which was consistent with the low lube oil pressure alarm set point.

Procedure 1032.034 required that system engineering personnel produce monthly, quarterly, and fuel cycle frequency reports. The quarterly and fuel cycle frequency reports were required to include trends of the recorded parameters. Degrading operating parameters were required to be addressed by initiating a maintenance work document and a CR was required to be written for all cases where EDG operating characteristics were beyond the limits of the manufacturer.

The inspectors requested copies of the required EDG 2 reports. The licensee informed the inspectors that the system engineer had not been completing these reports. The system engineer had completed the cycle reports at the end of each refueling outage, which contained a general discussion of the health of the system. The inspectors reviewed the Unit 1 EDG cycle report issued following Refueling Outage 1R14 and it did not address the degrading trend in EDG 2 lube oil pressure or contain all of the information required by Procedure 1032.034. Similarly, Procedure 1032.033, "Unit 2 Emergency Diesel Generator Reliability Program," Revision 2, was not being performed for the Unit 2 EDGs. The licensee initiated CR C-1999-217 to document that these procedures were not being implemented for either Units 1 or 2.

Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by documented instructions and shall be accomplished in accordance with the instructions. The inspectors concluded that the licensee's failure to implement the requirements of Procedures 1032.033 and 1032.034 for preparing EDG reports is a violation of Criterion V. This Severity Level IV violation is being treated as a noncited violation (50-313/9915-02; 50-368/9915-02), consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR C-1999-217.

The licensee informed the inspectors that the EDG reliability calculation portions of Procedures 1032.033 and 1032.034 had been performed as part of other site programs. For example, EDG reliability was calculated (based upon the number of EDG start failures and load-run failures) for determination of safety system performance indicators and NRC Maintenance Rule impact. However, the performance monitoring portions of the procedures had not been performed. The licensee resumed performing the performance monitoring requirements of the procedures as corrective action from CR C-1999-217.

c. Conclusions

The licensee was not implementing the procedural requirements of its EDG reliability monitoring program. The inspectors concluded that if the reports required by the EDG reliability monitoring program had been completed and reviewed by plant management, an additional opportunity for identification of the degrading EDG 2 lube oil pressure trend would have existed and may have resulted in correcting the condition prior to failure. A violation of Criterion V was identified for the failure to follow the procedural requirements of the EDG reliability monitoring program. This Severity Level IV violation is being treated as a noncited violation in accordance with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR C-1999-217.

M3.3 Local Copy of EDG Operation and Alarm Response Procedures

While observing maintenance activities in the EDG 2 room, the inspectors noted that current revision copies of Procedures 1104.036 and 1203.012A, "Annunciator K01 Corrective Actions," Revision 32-02, were located in an annunciator corrective action storage locker near the EDG control cabinet. The inspectors noted that there was no similar storage locker or copies of the procedures maintained in the EDG 1 room. Unit 2 EDG rooms had copies of EDG operations procedures and alarm response procedures located in each EDG room. The inspectors reviewed Procedures 1000.006, "Procedure Control," Revision 47-04, and 1013.002, "Document Control and Procedure Distribution," Revision 38, and noted that neither procedure required distribution of controlled copies of the EDG operations or alarm response procedures in both EDG rooms.

The inspectors informed a Unit 1 shift superintendent, who was leading one of the licensee's event response teams, of this observation. The inspectors were informed that operators have a copy of applicable section of the EDG operations procedure with them during EDG operation and that, if EDG 1 is in service and an operator needed to review an alarm, the operator could obtain the copy of Procedure 1203.012A from the EDG 2 room. Although allowed by the licensee's administrative requirements for procedure distribution, the inspectors considered this a poor operating practice. Additional time would be required to obtain the procedure from the other EDG room and review the applicable alarm response instruction. Also, other circumstances may prevent obtaining or cause additional delay in obtaining the procedure. These circumstances may include a fire or loss of lighting during a loss of offsite power event.

M4 Staff Knowledge and Performance (71707, 61726)

M4.1 Operating EDG 2 with Lube Oil Pressure Below Procedure Limit

As discussed in Section M1.3, EDG 2, on July 1, 1999, was operated with lube oil pressure below the 35 psig limit specified in Procedure 1104.036. Procedure 1015.001, "Conduct of Operations," Revision 51-01, identified that guidance on adherence and use of operating procedures was contained in Procedure 1000.006, "Procedure Control." Procedure 1000.006 prohibited operation of a system or component outside the limits of the procedure in use. Criterion V of Appendix B to 10 CFR Part 50 requires, in part, that activities affecting quality shall be prescribed by documented instructions and shall be accomplished in accordance with the instructions. Operation of EDG 2 outside of the limits of Procedure 1104.036 was prohibited by Procedure 1000.006 and is a violation of Criterion V. This Severity Level IV violation is being treated as a noncited violation (50-313/9915-03), consistent with Section VII.B.1.a of the NRC Enforcement Manual. This violation is in the licensee's corrective action program as CR 1-1999-178.

M8 Miscellaneous Maintenance Issues (71707, 62707, 61726, 37551, 92700)

M8.1 (Closed) LER 50-313/99-002-00: TS allowable outage time for one EDG was exceeded due to idler gear stubshaft bracket bolting failure caused by loss of bolt preload

The inspectors verified the immediate corrective actions and found them to be adequate and complete as described in LER 50-313/99-002-00, dated August 5, 1999.

M8.2 Unit 1 - Results of Licensee's Event Investigation Teams

In response to the July 1 EDG 2 test failure, licensee management formed event investigation teams to review the June 30 EDG 2 low lube oil pressure trip event, stubshaft bracket bolting failure, and programmatic issues associated with the EDG 2 lube oil pressure historical degrading trend. The inspectors received periodic briefings by team members during their investigations and reviewed the teams' findings and conclusions.

The licensee's event investigation teams generally conducted thorough reviews of the EDG 2 failure issues, identified valid root and contributing causes, and proposed a number of corrective actions that address the identified causes. However, as discussed in Section M3.2, the event investigation team's investigation associated with programmatic issues did not identify that the EDG reliability program procedures had not been implemented.

III. Engineering

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Inspection Followup Item (IFI) 50-368/9803-01: Followup of the licensee's evaluation of the process which authorized installation of the steam generator FME covers to determine if proper engineering reviews were performed.

On March 3, 1998, the licensee's quality assurance personnel identified that the use of the Unit 2 steam generator piping nozzle FME covers during reduced inventory operations was not evaluated prior to installation for impact on the assumptions for the RCS vent path size used in the calculation for time to boil and time to core uncovery. The licensee initiated CR 2-1998-0079. Subsequently, engineering personnel determined that the FME covers, which were designed to simultaneously prevent foreign material intrusion and provide a RCS vent path, did not significantly impact any of the calculations nor were any procedural requirements violated due to their presence. However, the installation of the FME covers was not previously evaluated for its effect on the RCS vent path assumptions prior to their installation or use. The licensee performed a formal root cause evaluation of the issue and determined that use of the FME nozzle covers was not interpreted by engineering personnel to be a temporary alteration at the time of the design and did not consider the potential impact on the assumptions used for the RCS vent path in the calculations. Engineering personnel had assumed that the RCS ventilation was adequate due to the fact that, if the RCS was to pressurize, the pressure exerted on the FME covers would be adequate to allow the release of the inventory around the covers. As part of the licensee's corrective actions, an evaluation of all steam generator procedures and engineering standards was performed to identify any temporary alterations issues which were not previously identified. In addition, the licensee's temporary alteration instructions were reinforced with involved engineering personnel training was conducted for engineering and operations personnel relative to ventilation pathways. All corrective actions identified in CR 2-1998-0079 to address this issue were completed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

During routine tours of the plant and observations of plant activities, the inspectors found that radiation protection personnel were properly performing their duties, that access doors to high radiation areas were properly locked, and areas were properly posted.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

During routine tours of the plant and observations of personnel access into the protected area, the inspectors found that security personnel were properly performing their duties and that access barriers to vital areas were properly locked.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee's staff on November 12, 1999. The licensee acknowledged the findings presented.

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

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

C. Anderson, General Manager, Plant Operations
B. Bement, Unit 2 Plant Manager
R. Carter, Unit 2 Maintenance Superintendent
M. Chisum, Manager, Unit 2 System Engineering
M. Cooper, Licensing Specialist
D. Fowler, Supervisor, Quality Assurance
R. Fuller, Unit 1 Manager, Emergency Preparedness
J. Jehlen, Unit 1 Acting Maintenance Superintendent
R. Lane, Director, Design Engineering
T. Mitchell, Unit 2 Operations Manager
R. Partridge, Manager, Chemistry
W. Perks, Manager, Technical Support
D. Phillips, Unit 1 Supervisor
S. Pyle, Licensing Specialist
J. Smith, Jr., Radiation Protection Manager
J. Souto, Unit 1 Emergency Diesel Generator
S. Stumbaugh, Assistant Outage Manager, Unit 1 Operations
J. Vandergrift, Director, Nuclear Safety

INSPECTION PROCEDURES USED

37551	Onsite Engineering
61726	Surveillance Observations
62707	Maintenance Observations
71707	Plant Operations
71750	Plant Support Activities
92700	LER Review
92903	Engineering Followup

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-313/9915-01	NCV	Failure to follow procedures involving initiating a CR (Section M2.3)
50-313;-368/9915-02	NCV	Failure to follow procedures involving EDG reliability program (Section M3.2)
50-313/9915-03	NCV	Failure to follow procedures involving operation of EDG outside of procedural limit (Section M4.1)

Closed

50-368/9803-01	IFI	Followup of the licensee’s evaluation of the process which authorized installation of the steam generator FME covers to determine if proper engineering reviews were performed (Section E8.1)
50-313/9915-01	NCV	Failure to follow procedures involving initiating a CR (Section M2.3)
50-313;-368/9915-02	NCV	Failure to follow procedures involving EDG reliability program (Section M3.2)
50-313/9915-03	NCV	Failure to follow procedures involving operation of EDG outside of procedural limit (Section M4.1)
50-313/99-002	LER	TS allowable outage time for one EDG was exceeded due to idler gear stubshaft bracket bolting failure caused by loss of preload (Section M8.1)

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
CR	condition report
EDG	emergency diesel generator
EFW	emergency feedwater
EMD	Electro-Motive Division
ES	engineered safeguard
FME	foreign material exclusion
IFI	inspection followup item
JO	job order
JR	job request
NCV	noncited violation
NOED	Notice of Enforcement Discretion
PDR	Public Document Room
RCP	reactor coolant pump
RCS	reactor coolant system
TS	Technical Specification