ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Report No.:	50-482/98-12
EA No..	98-274
Licensee:	Wolf Creek Nuclear Operating Corporation
Facility:	Wolf Creek Generating Station
Location:	1550 Oxen Lane, NE Burlington, Kansas
Dates:	March 23 through April 10 and June 22 through 25, 1998
Inspectors:	M. Runyan, Senior Reactor Inspector R. Nease, Senior Reactor Inspector P. Goldberg, Reactor Inspector R. Bywater, Reactor Inspector J. Hanna, Reactor Inspector D. Pereira, Reactor Inspector
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ATTACHMENT: Supplemental Information

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Wolf Creek Generating Station
NRC Inspection Report 50-482/98-12

Engineering

- The licensee made changes to Emergency Management Guidelines ES-12, "Transfer to Cold Leg Recirculation," that involved an unreviewed safety question, without prior Commission approval and without performing safety evaluations. This was identified as a violation of 10 CFR 50.59 (Section E1.1.2).

- The licensee's evaluations of discrepancies between the Updated Safety Analysis Report and Emergency Management Guidelines ES-12, reported in Performance Improvement Request 97-3483 were poorly performed, limited in scope, and ineffective in determining the proper priority of the performance improvement request. This resulted in untimely resolution of the issues (Section E1.1.2).

- The licensee's lack of resolve in minimizing emergency core cooling system leakage and the use of the filter cleaning handle in lieu of monitoring the filter pressure drop of the centrifugal charging pump lubricating oil filter, was identified as a weakness (Section E1.1.2).

- The lack of design basis calculations to support the minimum battery room temperature of 60 degrees F was identified as a weakness in the licensee's design basis documentation; however, available contingency actions were sufficient to address any safety concerns related to this matter (Section E1.2.2).

- The failure to identify Calculation NK-E-003, Revision 0, as an affected document in two design change packages, was identified as an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (Section E1.2.2).

- An inconsistency in the regulation specification for a battery charger purchase reflected weaknesses in the licensee's design and procurement processes (Section E1.2.2).

- Design Calculation NK-E-002, "Class 1E Battery Sizing," Revision 3, was of poor quality. It did not contain a visible load profile, the computer program was disorganized and the conclusions were not well supported (Section E1.2.2).

- There was a failure to correctly translate the design basis for the service water flow rate to the component cooling water heat exchangers. The design control measures did not verify or check the adequacy of Calculation E6-06-W. This was identified as an example of a violation of 10 CFR Part 50, Appendix B, Criterion III (Section E8.11).

- Design control measures did not assure the adequacy of the design for residual heat removal pump operation in the recirculation mode, in that the wrong initial water temperature was used in the calculation. This was identified as an example of a violation of 10 CFR Part 50, Appendix B, Criterion III (Section E8.13).

- The failure to develop appropriate acceptance criteria for station battery testing was considered an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (Section E8.21).

- Design control measures did not assure that effect of density variations on the refueling water storage tank level indication was considered in the tank level instrument uncertainties. This was considered to be an example of a violation of 10 CFR Part 50, Appendix B, Criterion III (Section E8.22).

- Design control measures did not properly verify or check the adequacy of the design basis differential pressure for component cooling water Motor-Operated Valves EG-HV-062 and 132. This was considered to be an example of a violation of 10 CFR Part 50, Appendix B, Criterion III (Section E8.25).

- Design control measures did not ensure that the effect of lower component cooling water water temperatures on safety-related motor oil temperatures and on the spent fuel pool reactivity were adequately verified or checked. This was considered to be an example of a violation of 10 CFR Part 50, Appendix B, Criterion III (Section E8.26).

- The failure to promptly correct a discrepancy regarding the component cooling water cooling water flow isolation to the spent fuel pool heat exchanger during cooldown was identified as a noncited violation (Section E8.27).

Plant Support

- The failure to include inspection and periodic replacement of the relays for the diesel-driven fire pump was identified as a weakness in the preventive maintenance program (Section F2).

- There were only four fire protection impairment control and breach authorization permits that required a compensatory fire watch. This was identified as a strength (Section F2).

- A noncited violation was identified for failure to maintain the fire protection system in accordance with the fire protection program as required by Operating License NPF-42, Section 2.C (5)(a), in that the licensee used the fire protection system for nonfire protection purposes, a practice that rendered the fire protection system temporarily inoperable (Section F8.2).

- A noncited violation was identified, in that, on three occasions the licensee identified leakage sites from the reactor coolant pump lube oil system that were not provided a collection system, as required by Operating License NPF-42, Section 2.C (5)(a) (Section F8.3).

REPORT DETAILS

III. Engineering

E1 Conduct of Engineering

E1.1 High Head Injection System

E1.1.1 System Description

High head injection is provided by two multistage centrifugal charging pumps (CCP). On a safety injection signal, the CCPs are automatically aligned for suction from the refueling water storage tank and discharge through the boron injection tank to the reactor coolant system (RCS). If the refueling water storage tank becomes depleted, the CCP suctions may be remote-manual transferred by control room operators to take a suction from the discharge of the residual heat removal pumps during containment sump recirculation.

E1.1.2 Design Review

a. Inspection Scope (93809)

The team reviewed 24 design calculations related to the high head injection system, including original architect-engineer calculations and more recent computerized flow models. The team also reviewed the accuracy of statements in the Updated Safety Analysis Report. In addition, the team reviewed surveillance testing and operations of the system.

b. Observations and Findings

Calculations for the most part were adequate for the situation. Some problem areas were identified and are discussed below.

Emergency Core Cooling System Switchover Operations

The team reviewed the actions required to switch the suction for the emergency core cooling system pumps from the refueling water storage tank to the containment sump as described in the Updated Final Safety Analysis Report and in the Emergency Management Guidelines ES-12, "Transfer to Cold Leg Recirculation," Revision 9.

Emergency Management Guideline, ES-12, "Transfer to Cold Leg Recirculation," Revision 9, describes operator actions necessary to switch the suction of the emergency core cooling system pumps, specifically the CCPs and safety injection pumps, from the refueling water storage tank to the containment sump upon the receipt of a refueling water storage tank Low-Low-1 level alarm. This action is required to ensure that these pumps are not lost due to air binding, and will be available for long-term core cooling. For this reason, the switchover is time critical. The suction path for the residual heat removal pumps automatically switches from the refueling water storage tank to the containment sump upon receipt of the refueling water storage tank Low-Low-1 level alarm. Updated Safety Analysis Report, Table 6.3-8, describes five numbered steps and one unnumbered step, which must be performed to accomplish switchover for the CCPs and safety injection pumps. The most time critical outflow analysis of the emergency core cooling system suction switchover, described in Updated Safety Analysis Report, Table 6.3-12, was a large break loss-of-coolant-accident in conjunction with a failure of one of the refueling water storage tank to residual heat removal suction valves to close. Updated Safety Analysis Report Table 6.3-12 provides a total of 4.41 minutes for those steps to be performed, which includes times for operator actions and times for the valves to reposition.

The team noted some discrepancies between operator actions required in Emergency Management Guidelines ES-12 and those described in the Updated Safety Analysis Report refueling water storage tank outflow analyses. In particular, operator actions required to realign component cooling water from the spent fuel pool heat exchanger to the residual heat removal heat exchanger were required by Emergency Management Guidelines ES-12 to be performed upon receipt of the refueling water storage tank Low-Low-1 level alarm. However, Updated Safety Analysis Report Table 6.3-8 stated, "(T)he operator initiates component cooling water to the residual heat removal heat exchangers and terminates cooling water to the fuel pool cooling heat exchangers as the level in the refueling water storage tank nears the Low-Low-1 level set point." In addition, as a result of the team's review of all the revisions to Emergency Management Guidelines ES-12, the team found that Revisions 3, 4, and 7 added operator actions, which increased the time required for operators to complete the emergency core cooling system switchover as described in Updated Safety Analysis Report, Section 6.3.

10 CFR 50.59(a)(1) states, in part, that the licensee may make changes to the facility without prior Commission approval as long as the changes do not involve an unreviewed safety question. 10 CFR 50.59(a)(2) states, in part, that a change is deemed to be an unreviewed safety question if the probability of a malfunction of equipment important to safety previously evaluated in the safety analysis report may be increased. 10 CFR 50.59(b)(1) states, in part, that the licensee must maintain records of all changes to procedure that constitutes a change in the facility as described in the Updated Safety Analysis Report, and that these records shall include a safety evaluation that provides the bases for the determination that the changes do not include an unreviewed safety question.

By adding operator actions to Emergency Management Guidelines ES-12, on three occasions, the licensee increased the amount of time required for the operators to complete the switchover. This increased the probability that the switchover would not be completed prior to the refueling water storage tank level becoming lower than the suction point for the emergency core cooling system pumps, resulting in the malfunction of one or more emergency core cooling system pumps. The team determined that the licensee made changes to Emergency Management Guidelines ES-12 which involved an unreviewed safety question without prior Commission approval was not obtained. This was a violation of 10 CFR 50.59 (50-482/9812-01).

The licensee's process for performing modifications or changes to design bases documents included an engineering screening to determine if a safety evaluation, as required by 10 CFR 50.59, was necessary. The team reviewed the engineering screenings for all revisions to Emergency Management Guidelines ES-12 and found that the licensee failed to identify that Revisions 3, 4, and 7 to Emergency Management Guidelines ES-12 involved changes to the facility as described in the Updated Safety Analysis Report and, therefore, did not perform safety evaluations for those revisions. The licensee's failure to perform safety evaluations for changes to the facility as described in the Updated Safety Analysis Report is part of the violation of 10 CFR 50.59 (50-482/9812-01).

The team requested that the licensee verify on the simulator that operators could perform the switchover actions required in Emergency Management Guidelines ES-12 in the 4.41 minutes provided in Updated Safety Analysis Report, Table 6.3-12. The team observed two attempts. The first attempt was completed in approximately 9 minutes and the second attempt was completed in approximately 11 minutes, both exceeding the 4.41 minutes provided in the Updated Safety Analysis Report. The licensee then performed an operability determination in accordance with Generic Letter 91-18 and determined that in the event that the suction for the emergency core cooling system pumps could not be switched to the sump, one residual heat removal pump (which changes suction automatically) would provide sufficient cooling to the core to prevent fuel damage. The team reviewed the operability determination and found it to be reasonable.

The team found that the licensee had previously identified and documented this issue in Performance Improvement Request 97-3483. This performance improvement request was initiated on October 29, 1997, to address discrepancies between Updated Safety Analysis Report, Sections 6 and 9, and Emergency Management Guidelines ES-12 that were found during the licensee's review of the Updated Safety Analysis Report. These discrepancies involved whether component cooling water was realigned to the residual heat removal heat exchanger before or after reaching the refueling water storage tank Low-Low-1 level set point. The screening, performed on October 30, 1997 to determine the priority of the performance improvement request, indicated that there were no operability or reportability concerns. Further evaluation of this performance improvement request on April 1, 1998, concluded that operators could perform the switchover before the refueling water storage tank was depleted, assuming that the additional steps to realign component cooling water to the residual heat removal heat exchanger took 2 minutes. This assumption was flawed in that it took 100 seconds for the valves to change state, leaving only 20 seconds for operator action. When performed in the simulator at the team's request, it took approximately 3 minutes for component cooling water to be realigned. Further evaluation dated December 22, 1997, concluded that component cooling water flow to the residual heat removal heat exchanger occurs before receipt of the Low-Low-1 level set point, which conflicts with Emergency Management Guidelines ES-12. The team found that the licensee's evaluations of conditions reported in Performance Improvement Request 97-3483 were poorly performed and limited in scope. In addition, the engineering screening and evaluation were ineffective in determining the safety significance of the condition, resulting in the licensee assigning a low priority to the resolution of the performance improvement request. At the time the team arrived onsite in April of 1998, the licensee had not correctly addressed the discrepancies between the Updated Safety Analysis Report and Emergency Management Guidelines ES-12, 5 months after identification.

Minimizing Emergency Core Cooling System Leakage During Emergency Operations

The team observed that a leak in the safety injection pump suction piping had not been corrected after almost 2 years following discovery. The licensee issued Performance Improvement Request 98-0841 in response to the team's concerns. The team concluded that the leak did not represent a safety concern, but considered the licensee's response to be lacking.

The team reviewed the licensee's management of valve seat and packing leakage for the valves in the containment sump recirculation flow path. The licensee provided a list of open corrective work packages as of April 1, 1998. Of the more than 70 items on the list, the team found one notable item involving cleaning of the CCP oil filter due to the handle being hard to turn (discussed below) and several items involving packing or seat leaks. The team observed no sense of urgency on the part of the licensee to identify and expedite the repair of the emergency core cooling system leaks.

The team determined that the licensee's slow response regarding emergency core cooling system system leakage was a weakness.

CCP Lubricating Oil System

The centrifugal charging pump technical manual specified that the normal pressure drop across the lubricating oil filter was 3 to 10 pounds per square inch (psi). However, pressure instruments did not allow operators to monitor the actual pressure drop across the oil filter. The filter was designed to be cleaned by the operator during operation by rotating a small handle on the top of the filter assembly, which caused debris to fall to the bottom of the filter bowl. Based on guidance from the filter vendor, the licensee stated that the filter was not actually removed and cleaned until this handle does not turn easily. This guidance had recently been incorporated into the quarterly flow tests (STS BG 100A/B, "Centrifugal Charging System Train Inservice Pump Test," Revision 19). The use of the handle feature in lieu of monitoring the filter pressure drop as recommended by the pump vendor has not been formally evaluated, and was identified as a weakness. The team did not have any safety concerns with the licensee's practice.

c. Conclusions

The licensee's management of the design basis of the high head injection system was observed to be generally satisfactory, with the following exceptions noted below.

On three occasions, the licensee made changes to Emergency Management Guidelines ES-12, "Transfer to Cold Leg Recirculation," (Revisions 3, 4, and 7) that involved an unreviewed safety question, without prior Commission approval. In addition, the licensee failed to perform safety evaluations for each of these changes. This was identified as a violation of 10 CFR 50.59.

The licensee's evaluations of conditions reported in Performance Improvement Request 97-3483 were poorly performed, limited in scope, and ineffective in determining the proper priority of the performance improvement request. This resulted in untimely resolution of the issues identified therein.

The licensee's lack of resolve in minimizing emergency core cooling system leakage and the use of the filter cleaning handle feature in lieu of monitoring the filter pressure drop of the centrifugal charging pump lubricating oil filter, as recommended by the pump vendor, was identified as a weakness.

E1.1.3 System Walkdown

a. Inspection Scope

The team conducted a plant walkdown of portions of the emergency core cooling system.

b. Observations and Findings

One item noted during this walkdown was a drip-collection funnel under a sump recirculation path component, the Safety Injection Pump B suction line spool piece. The funnel's purpose was to collect leakage from one of the flanges. This drip collection apparatus had been in place for more than a year. No performance improvement request or root cause evaluation was in place or planned. The licensee issued Performance Improvement Request 98-0841 in response to the team's concerns.

c. Conclusions

During a walkdown of the high head injection system, minor system leakage was noted. However, no significant findings were identified.

E1.2 Class 1E DC Power

E1.2.1 System Description

The dc power system included power supplies such as batteries and battery chargers, distribution systems such as switchgear, panels, and cables, and safety-related train load groups arranged to provide dc electrical power to Class 1E systems and equipment.

E1.2.2 Design Review

a. Inspection Scope (93809)

The inspection scope encompassed battery sizing calculations, dc minimum voltage calculations, the dc short circuit study, dc protective device coordination, the design change package for the battery replacement, the design change package for the swing battery charger replacement, and associated drawings, specifications, and supporting documents.

b. Observations and Findings

Battery Room Temperature Concerns

The team identified two concerns related to the temperature in the battery rooms:

1. Updated Safety Analysis Report, Section 9.4.1.2, stated that the ambient temperature in the battery rooms, under any mode of operation, is between 60 and 90 degrees F. Calculation NK-E-002, "Class 1E Battery Sizing" Revision 3, used 60 degrees F as the design input for analyzing the limiting capacity of the batteries. Based on these facts, the team asked the licensee to provide calculations to support the minimum battery room temperature of 60 degrees F, assuming winter conditions and a single failure of one train of heating ventilating and air-conditioning equipment. In response, the licensee indicated that there was no calculation to document that the temperatures in the battery room would not drop below 60 degrees F with a single failure.

   Additionally, the licensee stated that the standardized nuclear unit power plant system (SNUPPS) design basis assumed that heating systems for the control building were nonsafety related. The team noted that application of the single failure criterion usually required assuming credible failures of nonsafety-related equipment, which would include, for example, the nonsafety-related heating systems. The team reviewed control room logs of battery room temperatures over six randomly selected wintertime weeks. These logs indicated that battery room temperatures as low as 62 degrees F had been experienced, but had never dropped below the 60 degrees F minimum temperature. Based on the team's questions, the licensee outlined operator actions that would be instituted in the event the temperature fell to 60 degrees F or below. Based on these actions, the team determined that if battery room temperatures of 60 degrees F or below were experienced, these conditions would be limited in duration, and would not degrade battery capacity. The team considered the lack of design basis calculations to support the minimum battery room temperature of 60 degrees F to be a weakness.

2. The second concern involved the battery room thermometers used by control room operators to log battery room temperatures. The team noted that these thermometers had scales of 0-300 degrees F, with 1 degree F increments. The accuracy of the thermometers was ±1 degree F. The team considered these

thermometers to be adequate, but somewhat inappropriate for the condition being monitored. Following the identification of this concern by the team, the licensee issued Performance Improvement Request 98-0998 to improve the resolution and readability of the thermometers.

Failure to Identify Affected Controlled Documents

The team identified two concerns related to the licensee's failure to identify controlled documents affected by a design change:

1. Design Change Package 05846, "NK Battery Replacement," Revisions 0 through 11, installed new AT&T round cell batteries. Though these batteries were functionally similar to the existing batteries, they were of a different construction and had different ampere-hour ratings and short circuit contributions. The licensee stated that they had data indicating the new AT&T batteries had a lower short circuit contribution than the old batteries. Based on this information, the licensee chose not to identify Calculation NK-E-003, "Class 1E 125 V DC Batteries Short Circuit Study," Revision 0, as an affected document, since it was assumed there would be no adverse impact.

2. Design Change Package 05248, "NK System Swing Battery Charger Installation," Revisions 0 through 9, was closed out in November 1997. Knowledge of fault current levels at various locations within the ac and dc systems were essential to this design change package in order to correctly specify the ratings of equipment to be procured. As such, Revision 0 of the design change package correctly identified Calculation NK-E-003, "Class 1E 125 V DC Batteries Short Circuit Study," Revision 0, as the source document for dc fault current data. However, subsequent to Revision 0 of the design change package, the new AT&T batteries with changed fault contributions were installed. This fact was not identified in Revisions 1 through 9 of the design change package. The licensee had data indicating that the new AT&T batteries had a lower short circuit contribution than the old batteries, and therefore the licensee did not revise Calculation NK-E-003, or identify it as an affected document.

The team determined that the short circuit contribution from the batteries should have been included in Calculation NK-E-003. Procedure AP 05-001 "Change Package Planning and Implementation," Revision 2, Section 6.2.3, required that all programs requiring revision, such as calculations be identified. The inspectors did not consider this issue to involve a functional problem with the batteries, since the assumption of decreased short circuit contribution was considered to be correct.

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures. The failure to follow Procedure AP 05-001 and identify that Calculation NK-E-003 required a revision as the result of Design Change Package 05246 and 05248 was identified as an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (50-482/9812-02).

Purchase and Installation of Equipment

Battery Chargers NK-21 through NK-25 were purchased under Specification E-051(Q), "Battery Chargers for SNUPPS," Revision 5. Battery Charger NK-26 was purchased under Specification E-051A(Q), "Swing Battery Chargers for WCGS," Revision 2. The two spare Battery Chargers NK-25 and NK-26 were permitted by technical specifications to function in place of the permanent Chargers NK-21, 22, 23, and 24. The Updated Safety Analysis Report relating to Amendment 104 stated that the spare battery chargers were intended to be equivalent to the permanent chargers. However, Specification E-051(Q), (for Chargers NK-21 through NK-25) specified a regulation of ±0.5 percent; whereas, Specification E-051A(Q), (for NK-26) specified a regulation of ±1.0 percent. This difference in regulation requirements and its significance was not evaluated in Design Change Package 05248, "NK System Swing Battery Charger Installation."

The data sheet from the battery charger vendor showed that the vendor had, in fact, supplied a battery charger with ±0.5 percent regulation even though this was not consistent with the purchase specification.

This was considered to be a weakness in the licensee's design processes.

Poor Quality Calculation

The team reviewed Calculation NK-E-002, "Class 1E Battery Sizing," Revision 3, and found it to contain the following discrepancies:

- The calculation had no visible load profile. Part of the data used to represent the load profile came from a computer program, and part from a manual tabulation, and no explanation was provided on how the two sources were to be combined to define the load profile.

- The computer program was disorganized and was unable to sort, summarize, and present data in a logical format needed to determine the load profile.

- The conclusions were unsupported by the calculation. The team needed extensive explanations by the licensee in order to understand their derivation.

- Section 5.2.5 of the calculation indicated that to provide conservatism and extra margin, the calculation would utilize a minimum battery voltage of 1.8 V per cell. Nonconservative values of 1.788 V and 1.79 V were utilized in the worksheets and attachments to the calculation. The team considered this discrepancy to be minor in that it did not affect the overall battery profile.

The licensee acknowledged the problems with this calculation after attempting to provide the team with an overview of the calculation and its conclusions. The licensee issued

Performance Improvement Request 98-1007 to enhance the calculation. Based on review of other documents and discussion with the licensee, the team concluded that the batteries were properly sized. However, the poor quality of Calculation NK-E-002 was identified as a weakness. An inspection followup item (50-482/9812-03) was identified to review the calculation after it is enhanced by the licensee.

Drawing Error

The team reviewed Drawing M-1G051, "Equipment Locations Control & Diesel Gen. Bldg & Common Corridor Plan El. 2000'-0" & El. 2016'-0"," Revision 8, and found that it did not show Battery Charger NK 21 on Plan Elevation 2016 feet 0 inches. All other battery chargers at this elevation were correctly identified. The licensee stated that this oversight would be corrected.

c. Conclusions

The team noted that calculations and other design products in the electrical area were of inconsistent quality and contained errors. These problems appeared to stem from a lack of attention to detail, a lack of a questioning attitude, and weak independent verification of calculations and design change packages.

The lack of design basis calculations to support the minimum battery room temperature was identified as a weakness in the licensee's design basis documentation. However, available contingency actions were sufficient to address any safety concerns related to this matter.

The failure to identify Calculation NK-E-003 as an affected document in the two design changes was identified as an example of a violation of 10 CFR Part 50, Appendix B, Criterion V.

An inconsistency in the regulation specification for the purchase of a battery charger reflected weaknesses in the licensee's design and procurement processes.

E1.2.3 System Walkdown

a. Inspection Scope

The system walkdown consisted of detailed inspections of the battery rooms, the batteries, the battery chargers, the spare battery chargers, the transfer switches associated with the battery chargers, and various dc switchgear and control panels.

b. Observations and Findings

Seismic Qualification of Electrical Panels

During the walkdown, the team noted that Electrical Cabinets NK-77, NK-25, and NK-75; NK-01 and NK-71; and NK-04 and NK-74 were connected to each other by 4-inch diameter, short, rigid conduit. Electrical Cabinets NK-71, NK-74, NK-75 and NK-77 were installed as a result of DCP 05248, "NK System, Swing Battery Charger Installation," in November 1997. Cabinets NK-01and NK-25 weigh approximately 1800 lbs and were more flexible horizontally than the new cabinets (NK-71, -74, -75, and -77), which weigh approximately 500 lbs. each and are considered to be horizontally rigid. The differences in height, plan dimensions, and mass distribution could result in different dynamic responses during a seismic event. Upon questioning the licensee regarding the interaction between the cabinets, the team was informed that each cabinet was independently seismically tested and qualified, however no formal calculations to address interaction between the cabinets had been performed. The licensee stated that the conduit had been installed in accordance with drawing -1R8900, "Raceway Notes, Symbols, and Details," paragraph 3.35 of Revision 15, dated January 2, 1997, which stated, "Only flexible conduit shall be fastened to any equipment which requires seismic qualification except when the installation is such that the equipment and the last support for the conduit are attached to the same surface (plane). . . ." The licensee stated that the basis for this specification is that, during a seismic event, equipment connected via rigid conduit and mounted on the same plane, is expected to initially react in the same direction. The team agreed, but given the differences in mass and dimensions questioned the interaction between the cabinets during the entire seismic event. The licensee initiated Performance Improvement Request 98-0986 to perform a calculation explicitly addressing the team's concerns. An inspection followup item (50-482/9812-04) was identified to review the new calculation.

c. Conclusions

The seismic qualification of selected electrical panel was indeterminate. With the exception of this seismic qualification issue, the walkdown did not identify problems with the dc distribution system.

E1.3 Control Room Heating, Ventilation, and Air Conditioning

E1.3.1 System Description

The control room heating, ventilation, and air-conditioning system is an emergency ventilation system and part of the control building ventilation system. The control room emergency ventilation system consists of three subsystems: air conditioning, filtration, and pressurization. These three subsystems protect control room operators from receiving excessive doses of radiation during postulated accidents involving the release of large amounts of radioactive materials, including fission products. Several automatic isolation functions ensure that control room operators are protected during accident conditions. The control room air-conditioning system also provides the control room with a conditioned atmosphere during all modes of plant operation, including post-accident operation.

E1.3.2 Design Review

a. Inspection Scope (93809)

The team evaluated the control room ventilation system post-accident design safety features, the test program for those features, and the operations associated with those features. During its review of the applicable sections of the technical specifications and Updated Safety Analysis Report, the team identified 16 specific design topics or requirements for the control room ventilation system.

The team reviewed 38 design calculations, surveillance tests, procedures, and related documents for the control room emergency ventilation system, which includes subsystems for temperature control, filtration, and pressurization. The related additional documentation primarily involved the charcoal adsorber testing program, including changes applicable to laboratory analysis of charcoal samples. Design calculations reviewed by the team included the effects of single failures, charcoal adsorber specifications, the potential for carbon dioxide buildup during control room isolation, and heat load changes due to equipment modifications.

b. Observations and Findings

No significant issues were identified in the design review of the control room ventilation system.

E1.3.3 Design Changes

a. Inspection Scope (93809)

The team reviewed three design changes affecting the control room ventilation system.

b. Observations and Findings

Deletion of Relative Humidity Sensors

Proposed Modification Request (PMR) 03158, "Deactivation of RH [relative humidity] Sensors and Transmitters," Revision 2, was issued due to the unavailability of replacement relative humidity sensors to control the intermittent operation of ventilation system heaters, used to maintain the required 70 percent relative humidity of air into the charcoal adsorber media. The heaters were modified for continuous operation whenever the pressurization systems are in operation. The team considered this modification to be acceptable since heater operational reliability was improved.

Heater Capacity Reduction

By letters dated October 24, 1995, and May 16, 1996, the licensee requested revisions to the technical specifications that allowed the rating of the control room ventilation pressurization system heaters to be reduced from 15kW to 5kW. The team reviewed the supporting Calculation GK-474, "Control Room Pressurization System Filtration Unit Heater Output," Revision 1, which showed that 5kW was adequate to achieve the 70 percent relative humidity required to ensure charcoal bed adsorption efficiency. This request was consistent with PMR 03158, Revision 2, which resulted in continuous heater operation when the system is in operation. The team considered that continuous operation of 15kW heaters would add unnecessary heat to the control room ventilation system.

The team considered the request to downrate the heaters to be the result of the original problem with maintaining or replacing the relative humidity sensors. Nevertheless, in view of the periodic charcoal drying operations performed by the licensee, the continuous heater operation described above, the power supply conservatism noted in the calculation, and the industry practice of using approximations in ventilation system calculations, the team agreed that the specified reduction in heater capacity was acceptable.

Charcoal Laboratory Test Change

The same technical specification revision request included changes to the laboratory methods used to test the efficiency of the charcoal adsorber media. The change was made to address interference of test results from the moisture introduced by the test method. Since the charcoal is sensitive to moisture, the team was concerned that the efficiency of the installed charcoal beds may be compromised by condensation of water vapor during regular operation. The licensee provided the team with further information showing that the ventilation systems for the charcoal beds are periodically operated specifically to ensure that moisture was not collecting in the charcoal. The team reviewed the associated documentation and considered this approach to be adequate.

c. Conclusions

The three design changes reviewed were considered acceptable.

E1.3.4 Technical Specification Surveillance Testing

a. Inspection Scope (93809)

The team reviewed technical specification testing of the control room ventilation system. Control room emergency ventilation system surveillances reviewed by the team included visual, flow, pressurization, high efficiency particulate air filter efficiency, leakage, and charcoal adsorber sample laboratory test results. The team also assessed the quality of the documentation of the surveillance tests since 1994.

b. Observations and Findings

While all of the surveillances reviewed by the team were performed adequately, the team noted that the licensee closed out one charcoal filter surveillance without including the laboratory results. This was a surveillance in which the charcoal adsorber failed a concurrent leak test, which resulted in the licensee having to replace the charcoal. The licensee discarded the old charcoal test results. Although it was not specifically required, the team noted that it may be important to collect, review, and retain all sampling results for safety systems, even when those results are of no immediate operational value.

c. Conclusions

Technical specification surveillances of the control room ventilation system were properly performed.

E1.3.5 System Walkdown

a. Inspection Scope (93809)

The team walked down the control room emergency ventilation system.

b. Observations and Findings

The system engineer was very familiar with the various components in the system and was very knowledgeable regarding the associated surveillance testing programs. The equipment appeared to have adequate clearance for maintenance and testing operations, and the material condition of the major system components was good. Maintenance of smaller components was good, with some minor exceptions resulting from condensation and possible leaks in the air-conditioning equipment.

The team also visited the control room to assess the operational aspects of the control room emergency ventilation system. The operators were very knowledgeable regarding system operations and they stated that they were comfortable with the human factors aspects of the system control and indication panels.

c. Conclusions

The material condition of the control room ventilation system was good.

E1.4 Performance Improvement Requests

a. Inspection Scope (93809)

The team reviewed Procedure AP 28A-001, "Performance Improvement Request," Revision 9, and 55 performance improvement requests associated with the high head safety injection system, control room ventilation system, and the Class 1E dc distribution system. The team discussed the performance improvement request process and some of the performance improvement requests with appropriate licensee personnel.

b. Observations and Findings

The team determined that the performance improvement request process provided a single method for documenting the evaluation and resolution of problems, concerns, or recommendations.

As the result of this review, no problems were identified with the selected performance improvement equests.

c. Conclusions

The team found the licensee's disposition of performance improvement requests to be appropriate.

E8 Miscellaneous Issues (92903, 37550)

E8.1 Engineering Backlog

a. Inspection Scope

The team reviewed the licensee's engineering backlog and the manner in which the backlog was being trended and tracked. In addition, the team discussed the backlog with appropriate licensee personnel.

b. Observations and Findings

The team noted that the open performance improvement requests had an upward trend over the past 2-year period. In January 1996 there were approximately 290 open performance improvement requests and in March 1998 there were approximately 460 open performance improvement requests. The team also found that vendor technical documents increased from 74 open items in April 1997 to 435 open items in April 1998. In addition, the licensee's design change package closeout backlog increased from 72 in December 1996 to 220 in February 1998. The change package closeout backlog consisted of a number of change packages awaiting engineering closeout by design engineering or the configuration control group that were greater than 90-days old.

The team discussed the engineering backlog with the licensee and determined that, in the summer of 1997, the licensee was authorized to hire contractors to reduce the backlog. The team reviewed Material/Service Requisition DES 930023, dated March 24, 1998, which was initiated by the licensee to obtain contractors to provide engineering services to manage and implement the backlog reduction project. The licensee stated that the work scope would start in early May 1998 and be completed by the end of December 1998. The team found that the backlog reduction project consisted of four specific areas - change package backlog, performance improvement requests, motor-operated valve backlog, and reverification of safety classification analyses. The change package backlog scope was 268 change packages which consisted of 2065 documents that required review and revision. The performance improvement request backlog consisted of 165 documents that required investigation of predominately auxiliary feedwater system, essential service water system, and component cooling water system hardware and documentation discrepancies. The motor operated valve backlog scope consisted of resolution of 54 items, which the licensee stated would take approximately 4800 man-hours. The reverification of 532 safety classification analyses required independent review, validation and correction of previously performed safety classification analyses. The team was not able to draw any conclusions regarding the backlog reduction project since the project had not yet started.

c. Conclusions

The team determined that while there was an overall upward trend in the engineering backlog, the licensee was in the process of taking action to reduce the backlog by initiating a backlog reduction program.

E8.2 Pressurizer Safety Valve and Main Steam Safety Valve Test Data Review

a. Inspection Scope

The team reviewed a few performance improvement requests associated with the main steam safety valves and pressurizer safety valves. The team discussed some of these documents with appropriate licensee personnel.

b. Observations and Findings

The team reviewed Performance Improvement Request 97-2539, dated August 19, 1997. The licensee issued this performance improvement request to document the failure to perform an internal visual examination, VT-3, on one of the pressurizer safety valves during the first 10-year inspection interval of the inservice inspection program. The team determined that on August 19, 1997 the licensee performed a VT-3 inspection on a pressurizer safety valve which was installed during the fall of 1997 outage. The team noted that the VT-3 results were satisfactory, with no indication of degradation. In addition, the licensee generated LER 97-015 to report the missed surveillance. Additional corrective actions planned included revising Procedure STS MT-005, "Pressurizer Code Safety Valve Operability," to specify that VT-3 examination was required during disassembly of the pressurizer safety valves and revising the second interval inservice inspection program plan to specify the required examinations in each of the three periods within the second 10-year inspection interval.

The team reviewed the set pressure inservice test results for the pressurizer safety valves and main steam safety valves from March 1993 to February 1998. The team found that, during testing in June of 1993, two of the pressurizer safety valves exceeded their set points. The technical specification set point requirement was 2485 psig

+/- 1 percent. The two valves that failed, opened at -2.13 and -2.70 percent below the nominal set point. During the July 1996 testing, one of the pressurizer safety valves opened at 2534 psig which was +1.97 percent above the nominal set point. During the February 1998 testing, one valve opened at -1.81 percent below nominal set point. The licensee issued Performance Improvement Request 98-013 for these test failures on March 19, 1998.

c. Conclusions

The team found that the licensee was appropriately identifying and resolving issues involving pressurizer and main steam safety valve testing.

E8.3 Year 2000 Computer Issue

a. Inspection Scope

The team reviewed the adequacy of the licensee's Year 2000 (Y2K) program. The purpose of this review was to provide a preliminary review of the licensee's year 2000 preparedness and not a detailed performance-based appraisal.

b. Observations and Findings

The licensee has been closely following the guidance provided in NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness." The licensee appeared to be on schedule, which allowed a 6-month margin of error should difficulties arise during implementation. The program was comprehensive, as evidenced by a wide spectrum of departments (ranging from human resources and finance to operations) and computer applications (extending from microchips and software to entire computer systems) that were included. Wolf Creek Nuclear Plant's Project Plan covers a wide variety of contingencies (e.g., a relevant vendor being out of business or not assisting with needed information or service).

c. Conclusions

Although there were few objective criteria to evaluate the licencee's performance, it appeared that the licensee was meeting their schedule on the Year 2000 computer issue and was following commonly accepted industry guidance.

E8.4 (Closed) Violation 50-482/9621-06: Procedure STS BG-004 did not Specifically Require Operators to Tighten or Verify the Mechanical Position Stops for Valves BGV-198, -199, -200, and -201

a. Background

Procedure STS BG-004, "Chemical and Volume Control system (CVCS) Seal Injection and Return Flow Balance," Revision 4, provided procedural guidance for setting the positions of seal injection throttle Valves BGV-198, -199, -200, and -201, and performing

Technical Specification Surveillance Requirement 4.5.2.g (verifying the correct position of mechanical position stops) for these valves. However, Procedure STS BG-004 did not specifically require operators to tighten the mechanical stops for these valves.

b. Inspection Followup

The licensee stated that the root cause of the violation was inadequate procedural guidance, since Procedure STS BG-004 failed to provide adequate instructions. The procedure did not require the performers to tighten, nor verify tightened, the locknuts (mechanical stops) on CVCS valves BGV-198, 199, 200, and BGV-201. The licensee stated that a contributing factor was that Procedure AP 21G-001, "Control of Locked Component Status," Revision 6, failed to define or give examples of a mechanical stop.

The inspection team reviewed the licensee's completed corrective actions to prevent recurrence of the violation. These specific corrective actions included Revision 7 of Procedure AP 21G-001, to clearly define what constituted a mechanical stop. In addition, the licensee revised Procedure STS BG-004, with Revision 6, to incorporate instructions to assure that the mechanical position stops are tightened or verified tightened.

The team reviewed the corrective actions and concluded that they were appropriate to prevent recurrence of the violation. In addition, the inspectors reviewed revised Procedures AP 21G-001 and STS BG-004, and determined that the revisions appropriately addressed the discrepancy.

E8.5 (Closed) Violation 50-482/9621-05: Operability Determination Was Not Thoroughly Documented in the Shift Supervisor's Log as Required by Administrative Procedures

a. Background

While performing an operability determination, a shift supervisor relied on an out-of-date Calculation, GN-MW-005, which assumed a flow rate of 4000 gpm for a cooler group (i.e., two coolers), instead of determining the actual requirement for containment air cooler group essential service water flow rate of 2000 gpm.

b. Inspection Followup

The licensee stated that the shift supervisor made an operability determination without following administrative guidance. However, the licensee's evaluation and root cause analysis of the event determined that the shift supervisor was correct in the determination that no operability or reportability concerns existed. The licensee stated that the root cause was personnel error in that the shift supervisor did not meet the procedural requirements of Procedure ADM 02-024 (since superseded by Procedure AP 26C-004), "Technical Specification Operability," Revision 3, in that the basis for the operability determination was not documented in the shift supervisor's log.

The team reviewed the licensee's completed corrective actions to prevent recurrence of the violation. These specific corrective actions included the following:

1. Performance Improvement Request 96-2737 was entered into operations required reading to remind the shift supervisors of management's expectation regarding detailed log entries and a questioning attitude.

2. Procedure AP 26C-004, Revision 0 (formerly Procedure ADM 02-024), was issued, with instructions that a detailed log entry will be made by the shift supervisor to record a decision concerning operability. The detailed log entry will include the basis for the operability decision.

3. Procedure AP 26C-004, Revision 1, subsequently added a "Technical Specification Operability Screening Form" as an aid to the shift supervisor to ensure thoroughness of evaluation and consistency in documentation.

The team's review of the above completed corrective actions indicated that they were appropriate to prevent recurrence.

E8.6 (Closed) Violation 50-482/EA96-470-02014: Two Examples of Inadequate 10 CFR 50.59 Safety Evaluations

a. Background

The NRC identified that the licensee made changes to procedures described in the Updated Safety Analysis Report without an adequate written safety evaluation which provided the basis for the determination that the changes did not involve an unreviewed safety question.

A. On December 13, 1995, the licensee's screening for revisions to Procedures STS PE-049C, "A Train Underground Essential Service Water System Piping Flow Test," Revision 2, and STS PE-049C, "B Train Underground Essential Service Water System Piping Flow Test," Revision 0, failed to indicate that Section 9.2 of the Updated Safety Analysis Report was affected by the change. The procedure revisions reclassified the essential service water system as nonredundant, whereas, the Updated Safety Analysis Report described this system as redundant. As a result, the licensee failed to either (1) submit a request for an alternative to the inservice inspection requirements or (2) process a change to Section 9.2 of the Updated Safety Analysis Report and determine whether the change involved an unreviewed safety question.

B. On March 26, 1996, the licensee performed an unreviewed safety question determination regarding changing the main turbine overspeed protection test frequency as stated in Section 16.3.2 of the Updated Safety Analysis Report from every 7 days to every 92 days, without providing supporting documentation to conclude that an unreviewed safety question was not involved. The unreviewed safety question determination did not address the licensee's experience with the testing of these valves and did not contain any information as to the acceptability, by the turbine vendor, of the decreased surveillance frequency on the turbine valves.

b. Inspection Followup

The licensee stated that the reason for Example A to the violation was personnel error. The inservice inspection engineer utilized his code experience and knowledge to assure that the changes were within the boundaries established by ASME, Section XI. During the procedure change to implement the new testing method, the inservice inspection engineer incorrectly concluded that the application of the code requirements (e.g., considering each train of essential service water as a nonredundant system) did not conflict with the Updated Safety Analysis Report description.

The licensee stated that the reason for Example B of the violation was failure to follow the procedural requirements of Administrative Procedure AP 26A-003, "Unreviewed Safety Question Determination," Revision 3. This procedure discussed the need and responsibility for assuring the completeness and accuracy of the information provided in the unreviewed safety question determination. The licensee stated that Procedure AP 26A-003 was not followed correctly, in that information helping to justify the acceptability of making the subject change was identified but not included in the unreviewed safety question determination.

The inspectors reviewed the licensee's completed corrective actions for both violations to prevent recurrence of the violation.

The licensee's corrective actions for Example A included the following:

- The licensee reviewed other plant systems that have buried components to determine if changes to pressure test methodology resulted from incorrectly defining the system as redundant or nonredundant. The licensee found no other examples.

- The licensee committed to the 1989 Edition of ASME, Section XI. As part of this commitment, the inservice inspection program plan has been revised and associated pressure test procedures were being revised to the new requirements.

- In order to implement the requirements for testing redundant and isolable components, permission was requested from the NRC to utilize the ASME, Section XI 1995 Edition with 1995 Addenda so that Subsection IWA-5244 may be applied to the essential service water buried portions of piping. The request to implement the 1995 Addenda requirements was made in letter ET 97-0040 dated April 24, 1997, to the NRC, and was pending at the time of the inspection.

The licensee's corrective actions for Example B included the following:

- The licensee counseled the preparer and approver of the unreviewed safety question determination relative to the missing information.

- The licensee reviewed the content of all other unreviewed safety question determinations performed by the same preparer for similar errors. No other examples were identified.

- In July 1996, engineering implemented the work product evaluation process. This process was used to reinforce management expectations involving complete documentation of work, attention to detail, and procedural compliance.

- The chief operating officer and the plant manager met with the plant safety review committee to reinforce expectations for thoroughness of review and review for completeness of documentation.

The licensee conducted leakage testing of the essential service water system underground piping. Train A testing was performed on November 5, 1997, and Train B testing was performed on October 30, 1997. Both service water system piping leakage tests were performed satisfactorily, with no noted test deficiencies.

At the time of this inspection, the licensee was revising pressure test procedures (approximately 70) to satisfy the new testing requirements. The update to the pressure tests entailed a review of all system boundaries that require pressure testing. Updating the pressure tests was required to be completed with performance of the tests at the completion of the first 40-month inspection period in accordance with 10 CFR 50.55a and ASME, Section XI. The licensee stated that updating of the pressure tests would be completed by Refueling Outage 10, scheduled for the spring of 1999.

The team reviewed 5 of 11 recently revised pressure tests. The team noted that the revisions placed the tests in new and consistent formats and included changes necessary to meet the requirements of the 1989 Edition of ASME Code. The applicable signoffs on the data sheets were revised to require a review of the inservice inspection engineer for acceptance.

The inspectors concluded that the corrective actions appeared to be comprehensive and that the root causes were addressed to prevent recurrence of the violation.

E8.7 <u>(Closed) Violation 50-482/EA96-470-01013</u>: Five Examples Where the Licensee Failed to Identify and Correct Conflicts Between Technical Specification Clarifications and the Technical Specifications

a. <u>Background</u>

On March 31, 1994, the licensee's corrective actions in response to Quality Assurance Audit K381 findings failed to identify and correct conflicts between technical specification clarifications and the technical specifications. Specifically, the licensee's screening of the following technical specification clarifications did not identify conflicts between the technical specification clarifications and the technical specifications.

- Technical Specification Clarification 009-85 conflicted with Technical Specifications 3/4.5.3 and 3/4.5.4 (applicable in Modes 4 and 5, respectively) by allowing two centrifugal charging pumps to be available while in cold shutdown. Technical Specifications 3/4.5.3 and 3/4.5.4 allowed only one centrifugal charging pump to be available during cold shutdown.

- Technical Specification Clarification 010-85 conflicted with Technical Specifications 3.5.3 and 4.5.2 by allowing daily containment closeout inspections following multiple containment entries in 1 day. Technical Specifications 3.5.3 and 4.5.2 require a containment visual inspection for loose debris be performed following each containment entry.

- Technical Specification Clarification 033-85 conflicted with Technical Specification 3.6.1.1 by allowing containment penetrations to be considered operable if dedicated operators were assigned to close inoperable containment isolation valves. Technical Specification 3.6.1.1 requires that all containment penetrations be isolable by automatic isolation valves.

- Technical Specification Clarification 004-86 conflicted with Technical Specifications 4.5.1 and 4.0.3 allowing cold leg accumulators to be considered operable upon receipt of level and pressure alarms if accumulator level and pressure were within prescribed limits. Technical Specifications 4.5.1 and 4.0.3 require the accumulators to be considered inoperable upon receipt of these alarms.

- Technical Specification Clarification 005-94 conflicted with Technical Specification 4.8.1.1.2.g.7 by allowing hot restart testing of an emergency diesel generator to be performed any time before or after the 24-hour load test as long as the hot restart test was performed within 5 minutes of a 2-hour diesel run. Technical specification 4.8.1.1.2.g.7 specifies that a hot restart test be performed within 5 minutes following the 24-hour test except that the hot restart test may be done following a warmup run only if it previously failed the test immediately following the 24-hour test.

b. Inspection Followup

The licensee stated that the reasons for the violation included technical specification clarification procedural issues and weaknesses in the corrective action program, which allowed for a nonconservative interpretation of the regulatory requirements.

As background to this violation, the licensee identified in Quality Audit TE-50140-K381, "Technical Specifications and License Condition Adherence," dated March 4, 1993, that some technical specification clarifications appeared to contradict the associated Technical specification. As a result of this audit, Performance Improvement Request 93-0131 was written regarding the use of technical specification clarifications, and was classified as "nonsignificant." The performance improvement request initiation statement did not specifically identify any violations of technical specifications. However, the performance improvement request did state that certain technical specification clarifications could result in implementation of technical specifications, or changes to the technical specifications, that were not previously approved by the NRC as required by 10 CFR 50.92 and 10 CFR 50.36.

Performance Improvement Request 93-0131 recommended several corrective actions including: 1) a revision to the technical specification clarification procedure; 2) a 10 CFR 50.59 regulatory screening be performed for all open technical specification clarifications, and 3) an additional review be performed on all open technical specification clarifications to look for adequate technical basis, continued applicability, need for a license amendment, compliance with current NRC guidance, and appropriateness. This review resulted in the deletion of 11 technical specification clarifications, revision to 6 technical specification clarifications, and initiation of 1 technical specification amendment. The corrective actions were completed and Performance Improvement Request 93-0131 was closed on April 15, 1994. In addition, the licensee performed an effectiveness review on Performance Improvement Request 93-0131 and determined that the corrective actions were effective.

On October 16, 1996, Performance Improvement Request 96-2610 was written to document that Technical Specification Clarification 009-85 was not identified and deleted during the corrective action activities from Performance Improvement Request 93-0131. As a result of this oversight, licensee personnel performed another review of technical specification clarifications and identified several other technical specification clarifications requiring deletion. The licensee identified 14 clarifications that could have potentially caused a violation of the associated technical specifications. Of the 14, a total of 6 technical specification violations were identified and Licensee Event Reports 96-011-01 thorough 96-016-01 were issued.

The licensee's corrective actions to prevent recurrence of the violation included the following:

- In parallel to the review activities, the licensee chartered an Incident Investigation Team 96-004 on October 24, 1996, to conduct a programmatic investigation of technical specification clarification related processes and to identify root causes for the issuance of technical specification clarifications that caused or allowed technical specifications to be violated. As a result of Incident Investigation Team 96-004, Technical Specification Clarification Procedure, AP 26C-003, "Technical Specification Clarifications," was revised on April 10, 1997, with Revision 1. This revision accomplished the following items:

  - Step 5.4.1.2 was revised to require that the Manager Operations assure that each technical specification clarification receives a 2-year relevancy review.

- A note was added prior to Step 6.1.2 to denote that a technical specification clarification may not change the intent, scope, wording or meaning of a technical specifications.

- Reviews by the technical specification clarification subcommittee were required to be documented on Form APF 26C-003-02, "TSC Disposition Form."

- Disapproval of a technical specification clarification by the technical specification clarification subcommittee, plant safety review committee or plant manager was required to have written justification.

- technical specification clarification 2-year relevancy reviews were required to be approved by the technical specification clarification subcommittee chairman and the manager operations.

- technical specification clarification deletions were required to be recommended in writing and contain justification for deletion.

For compliance issues, the chief operating officer on February 28, 1997, completed sessions with all departments communicating management expectations regarding the need for verbatim compliance with nuclear regulatory requirements. An action plan for regulatory awareness training was completed on March 12, 1997. The purpose of this training was to effectively establish the culture of literal compliance with regulations through initial communications, as well as, continued re-enforcement of management expectations through the training process.

The corrective action program was modified to include the following:

- A corrective action review board was formed and met for the first time on November 11, 1996. The corrective acation review board was chartered to take a critical and questioning approach to each significant performance improvement request it reviews. The corrective acation review board was tasked to question whether the root cause was correctly identified, corrective actions were appropriate, and if the generic implications of the identified condition were addressed.

- Organizational changes were implemented. Each group within the plant operations organizations have performance improvement request coordinators, whose primary responsibility will be to support the corrective action process.

- Training was held for managers and performance improvement request coordinators on root cause analysis and human error prevention.

The licensee's leadership and selected membership changes to the plant safety review committee and the nuclear safety review committee (offsite) were made in order to provide consistency in executing management's expectations. Both committees were taking active roles in providing leadership and instruction to site personnel in the area of literal compliance.

The team reviewed the licensee's corrective actions and concluded that they were appropriate to prevent recurrence of the violation.

E8.8 <u>(Closed) Violation 50-482/EA96-470-01033</u>: Quality-Related Document Instruction Was Not Appropriate to the Circumstances When the Licensee Allowed the Reactor Coolant System to be Cooled Down With One Inoperable Source Range Channel

a. <u>Background</u>

The NRC identified that Technical Specification Clarification 001-94, conflicted with Technical Specification 3.3.1, Table 3.3-1, Functional Unit 6.b, Action 5, by allowing the reactor coolant system to be cooled down, an activity which involved a positive reactivity change, with one inoperable source range channel of nuclear instrumentation.

b. <u>Inspection Followup</u>

The licensee stated that the reasons for the violation included technical specification clarification procedural issues and weaknesses in the corrective action program, which allowed for a nonconservative interpretation of the regulatory requirements. The licensee also stated that during the editing process for a license amendment to Technical Specification 3.3-1, an ambiguity was created which affected the intent/meaning of an action statement.

Prior to Amendment 96, Action Statement 5a, read:

> "With the number of OPERABLE channels one less than the minimum channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor Trip Breakers, and suspend all operations involving positive reactivity changes and verify valves BG-V178 and BG-V601 are closed and secured in position within the next hour."

License Amendment 96 changed the wording to the following:

> "With the number of OPERABLE channels one less than the minimum channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor Trip Breakers, and suspend all operations involving positive reactivity changes within the next hour."

This word change resulted in an incorrect interpretation that positive reactivity changes were permissible after the reactor trip breakers were opened. As implied by the wording of the technical specifications prior to Amendment 96, no positive reactivity additions could be made after the reactor trip breakers were opened.

The team reviewed the licensee's completed corrective actions to prevent recurrence of the violation. These specific corrective actions included the following:

- Technical Specification Clarification Procedure AP 26C-003, "Technical Specification Clarifications," Revision 1, was issued on April 10, 1997. This revision revised several steps which included requiring the Manager, Operations to assure that each technical specification clarification received a 2-year relevancy review, and adding a note stating that a technical specification clarification may not change the intent, scope, wording or meaning of a technical specification.

- WCNOC Interoffice Correspondence Letter OP 97-0009, "Deletion of Technical Specification Clarification 001-94," was issued on March 25, 1997.

- Essential Reading Assignment 97-0011 was issued on March 27, 1997, to inform all licensed personnel, prior to assuming watch, that Technical Specification Clarification 001-94 was deleted.

- License Amendment Request, ET 97-0071, dated July 29, 1997, revised the wording of Action Statement 5a to Technical Specification, Table 3.3-1, "Reactor Trip System Instrumentation." The NRC issued Amendment 111 on September 29, 1997, which changed the wording of Action Statement 5a to Technical Specification, Table 3.3-1. The amendment statement prescribed the set of actions to be accomplished when a source range neutron detector was inoperable with the plant shutdown. This proposed wording change clarified the times and order in which these actions were to be performed.

The team reviewed the licensee's corrective actions and determined that they were appropriate to prevent recurrence of the violation.

E8.9 <u>(Closed) Violation 50-482/EA96-470-01023</u>: Reactor Coolant Pump Flywheel Inspection Integrity

a. <u>Background</u>

The NRC identified that the licensee, on January 11, 1995, made a change to a procedure described in the Updated Safety Analysis Report that involved a change to the technical specifications, without prior Commission approval. Specifically, the licensee changed the frequency for scheduled surface and ultrasonic examinations of reactor coolant pump flywheels, as described in Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity," which is described in Section 3A and 5.4.1 of the Updated Safety Analysis Report. However, the licensee did not recognize that the change also involved a change to the technical specifications, because the Regulatory Guide's examination schedule was specified by reference in Technical Specification 4.4.10 (which was superseded by Technical Specification 6.8.5.b on October 2, 1995).

Technical Specification, Section 6.8.5.b, specified the following requirement for the reactor coolant pump flywheel inspection program, "Each reactor coolant pump flywheel shall be inspected per the recommendation of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, dated August 1975."

Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity," Revision 1, Regulatory Position C.4.b states, in part, "In service inspection should be performed for each flywheel as follows: (2) A surface examination of all exposed surfaces and complete ultrasonic volumetric examination at approximately 10-year intervals, during the plant shutdown coinciding with the inservice inspection schedule as required by Section XI of the ASME code." In February 1995, Updated Safety Analysis Report Change Request 95-003 was implemented to add an exception to the commitment to Regulatory Guide 1.14, Revision 1, to address the frequency of the flywheel inspection. During the regulatory screening and 50.59 evaluation, it was not identified as a change to the technical specifications and, therefore, no prior approval from the NRC was sought.

b. Inspection Followup

The licensee stated that the reason for the violation included technical specification clarification procedural issues and weaknesses in the corrective action program, which allowed for a nonconservative interpretation of the regulatory requirements.

The licensee' s corrective actions to prevent recurrence of the violation included the following:

- A license amendment was submitted under WCNOC Letter ET 96-0097, dated December 3, 1996, requesting a revision to Technical Specification 6.8.5.b for inspection of the RCP motor flywheel. The amendment requested implementation of the alternative testing requirements previously accepted by the NRC for the Westinghouse Owners Group.

- Change Request 96-02 was incorporated into WCRE-10, "Second Interval In-service Inspection Program Plan," on January 9, 1997. This change revised the inservice inspection program plan to identify that the 10-year inspection of the flywheels shall occur within the 10-year inspection interval.

- Updated Safety Analysis Report Change Request 96-137 was initiated for correcting the changes made by Updated Safety Analysis Report Change Request 95-003 for inspection frequencies of the flywheel. Unreviewed Safety Question Determination 96-0191 was approved by the plant safety review committee on December 11, 1996, for this change request.

- A review of the technical specifications (up to Amendment 102) was performed by the licensee to identify references to regulatory guides. Subsequently, the Updated Safety Analysis Report was then reviewed to determine if changes to the Updated Safety Analysis Report were made regarding the commitments to the regulatory guides and the impact on the technical specifications. It was determined that those portions of the Updated Safety Analysis Report that were revised included either a technical specification revision to reflect these changes or that the technical specifications were not impacted by the revision.

- For compliance issues, the chief operating officer on February 28, 1997, completed sessions with all departments communicating management expectations regarding the need for verbatim compliance with nuclear regulatory requirements. An action plan for regulatory awareness training was completed on March 12, 1997. The purpose of this training was to effectively establish the culture of literal compliance with regulations through initial communications as well as continued re-enforcement of management expectations through the training process.

- For corrective action program issues, the corrective action program was modified to include the following:

  - A corrective acation review board was formed and met for the first time on November 11, 1996. Corrective acation review board was chartered to take a critical and questioning approach to each significant performance improvement request reviewed.

  - Organizational changes were implemented, such that each group within the operations department have performance improvement request coordinators whose primary responsibility will be to support the corrective action process.

  - Training was provided for managers and performance improvement request coordinators on root cause analysis and human error prevention.

The team reviewed and found the licensee's corrective actions to be appropriate to prevent recurrence of the violation.

E8.10 (Closed) Unresolved Item 50-482/9808-01: Licensee Failed to Prepare Performance Improvement Requests for 12 Updated Safety Analysis Report Significant Discrepancies

a. Background

The licensee identified 12 significant discrepancies in the Updated Safety Analysis Report, but did not initiate performance improvement requests to ensure corrective actions were initiated. An Updated Safety Analysis Report review database was established by the licensee to document discrepancies identified during the review process. Self-Assessment Plan SEL 97-044, "Wolf Creek Generating Station Updated Safety Analysis Report Fidelity Review," dated October 17, 1997, assigned responsibility for developing and maintaining a corrective action screening mechanism for Updated Safety Analysis Report discrepancies. The plan required that all corrective actions associated with the Updated Safety Analysis Report fidelity review be conducted in accordance with Procedure AP 28A-001, "Performance Improvement Request." The method for identifying the input forms was based on the number of the Updated Safety

Analysis Report chapter, section, paragraph, table, etc., that the discrepancy was being written against. The licensee stated that a group met twice a week to conduct an initial screening of discrepancies identified since the previous meeting. The twice weekly meetings limited the maximum time elapsed between discrepancy identification and initial screening to four days. On March 5, 1998, the NRC reviewed printouts from a sample of input forms which designated all the discrepancies as significant. The NRC identified 12 significant discrepancies that were older than one week for which the licensee had not generated a performance improvement request. The NRC noted that the discrepancies ranged from one week to five months old. The 12 discrepancies were as follows:

- Discrepancy 3.3.2-3051, dated 10/10/97, addressed the new radwaste building not being designed to preclude endangering safety-related structures or components when subjected to tornado loading.

- Discrepancy Table 15.7-7 (Section II)-4013, dated 11/12/97, addressed atmospheric dispersion factors during the fuel handling accident, in which, the potential existed for the control room dose to approach General Design Criteria 19 limits.

- Discrepancy 4.3.3.3-4787, dated 12/11/97, addressed a need for verification of spatial few-group diffusion calculations for reload cores because it appeared that some of the values were outdated.

- Discrepancy 6.2.1.1.2,c.-6484, dated 2/5/98, addressed a problem associated with calculated reactor containment internal pressures, temperatures, and inadvertent operation of the containment spray system.

- Discrepancy 15.0.3.3-5183, dated 2/6/98, addressed reactor core power distribution and questioned whether the historical uncertainty factor was appropriately factored into the nuclear enthalpy rise hot channel factor or the radial peaking factor.

- Discrepancy 16.7.2.1.1 (4.7.7), dated 2/6/98, addressed polar crane seismic restraints not being included in surveillance test procedures.

- Discrepancy 3.10(B).1-6936, dated 2/17/98, addressed apparent conflicts between Regulatory Guide 1.100, IEEE 344-1975, and the Updated Safety Analysis Report regarding seismic qualification criteria.

- Discrepancy 3.10(B).2-6982, dated 2/17/98, addressed an apparent conflict between Regulatory Guide 1.100, IEEE 344-1975, and the Updated Safety Analysis Report regarding methods and procedures for qualification of electrical equipment and instrumentation.

- Discrepancy 16.7.2.1 (3.7.8)-6550, dated 2/27/98, addressed limiting conditions for operation with respect to polar crane snubbers and the fact that they had not been appropriately inspected.

- Discrepancy 9.4.1.2.3-6349, dated 2/25/98, addressed a potential discrepancy identified between Calculation MGK-370, Revision 2, and the Updated Safety Analysis Report with respect to local hydrogen concentration in the control building.

- Discrepancy 9.4.1.2.3-6350, dated 2/25/98, addressed an additional discrepancy identified between Calculation MGK-370, Revision 2, and the Updated Safety Analysis Report with respect to maintaining hydrogen concentration levels below 0.5 percent volume by dilution with air provided by the control room pressurization system.

- Discrepancy 16.7.2.1.2-6692, dated 2/24/98, addressed modifications to 16 steam generator snubbers that might not be discussed appropriately in the current Updated Safety Analysis Report.

The NRC considered the licensee's failure to initiate performance improvement requests and determine appropriate corrective actions for the 12 discrepancies to be an unresolved item.

b. Inspection Followup

The team reviewed Procedure AP 28A-001, "Performance Improvement Request," Revision 9, the list of discrepancies, Self-Assessment Plan SEL 97-044, "Wolf Creek Generating Station Updated Safety Analysis Report Fidelity Review," and discussed this item with licensee personnel.

The team noted that Section 4 of Procedure AP 28A-001 stated that a performance improvement request, used to document the evaluation and resolution of problems, including conditions adverse to quality, nonconformances, deficiencies, and deviations, was required for equipment operation problems, program or procedure implementation problems, or work activities that do not occur as required.

The team found that Self-Assessment Plan SEL 97-044 required all corrective actions associated with the conduct of the Updated Safety Analysis Report fidelity review to be performed in accordance with Procedure AP 28A-001. However, the team noted that the intent of this referral to Procedure AP 28A-001 was to assure that discrepancies that affected plant operation or safety were appropriately entered into the corrective action process via the problem identification report. In addition, the team noted that SEL 97-044 provided the procedure to disposition identified discrepancies. This disposition required the discrepancies to be initially screened, followed by a detailed review of the discrepancy, and then resolution of the discrepancy through the normal corrective action process. As the result of these reviews and discussions, the team determined that SEL 97-001 and Procedure AP 28A-001 were being properly implemented.

The team noted that nine of the 12 discrepancies were less than one month old and that none of the 12 discrepancies involved issues that affected operability of plant systems, structures or components, nor did they affect plant safety. The team also noted that the licensee addressed the 12 discrepancies and either issued problem identification reports or determined that the discrepancy was minor in nature. Furthermore, to improve timeliness of processing USAR discrepancies, the licensee revised SEL 97-044 to assure that any potential identified discrepancy is resolved or a PIR initiated within 15 days of identification.

E8.11 (Closed) Unresolved Item 50-482/97201-01: Cooldown Analysis

a. Background

The NRC reviewed Westinghouse Analysis FSDA-C-365, "NSSS Uprating Analysis," Revision 1, which was performed for power uprate and which calculated the time required to bring the plant to cold shutdown so that neither the Updated Safety Analysis Report cooldown rate of 100 degrees per hour nor the cooldown time of 20 hours was exceeded. The time required to bring the plant to cold shutdown was dependent on the residual heat removal flow and the temperature of the component cooling water system. The component cooling water system temperature was dependent on the essential service water system temperature. The NRC determined from the analysis calculation that the plant could be brought to cold shutdown in approximately 17 hours with both residual heat removal pumps running. The NRC found that the calculation used reactor coolant system, residual heat removal system and component cooling water system flow rates that were consistent with the design bases. However, this calculation also used an essential service water flow rate of 13500 gpm to the component cooling water heat exchangers which was higher than that used in other calculations. The NRC reviewed Calculation EG-06-W, "Determine Flow and Heat Load Requirement," Revision W3. This calculation included flow reductions caused by plugging of up to 46 tube pairs to provide margin for the future should plugging of additional component cooling water heat exchanger tubes be necessary. The essential service water flow used in this calculation was 8800 gpm. The NRC noted that the Westinghouse analysis higher flow rate did not assume tube plugging. The licensee stated that only two tubes in one heat exchanger were plugged at the time. The licensee performed a preliminary evaluation of cooldown rate and time with the 8800 gpm flow rate and the two plugged tubes. This preliminary evaluation indicated that the cooldown rate and time would meet the values specified in the Updated Safety Analysis Report.

b. Inspection Followup

The inspectors reviewed Performance Improvement Request 97-4145, dated April 24, 1998, which discussed calculations with respect to differences in service water flow, the decay heat curve used, future tube plugging, and the time to cooldown. On March 9, 1990, the licensee completed Plant Modification Request 02149, which reduced the service water flow rate to the component cooling water heat exchangers to 8800 gpm. However, the licensee failed to review and revise the Westinghouse analysis to reflect the new design flow rate of 8800 gpm. In addition, the inspectors reviewed Change Package 07659, dated April 24, 1998, which the licensee prepared to remove unnecessary heat loads. To assure that the cooldown rate of 100 degrees F and time of 20 hours would be met, the licensee deleted use of the primary and secondary evaporators during cooldown. The inspectors noted that the evaporators were not required during cooldown and by deleting them, approximately 17 million BTUs/hr of heat load were removed. The inspectors determined that removal of the evaporator heat loads provided additional margin to meet the cooldown rate and time with both trains of the residual heat removal system operating as designed. The licensee revised a number of operations procedures to assure that the evaporators were not used during a cooldown. The inspectors also reviewed Updated Safety Analysis Report Change Request 98-069 dated April 22, 1998, and determined that the licensee also revised the Updated Safety Analysis Report to correct a number of errors dealing with the heat loads and cooldown time. The inspectors determined that the licensee's corrective actions, which included calculation and procedure revisions were comprehensive and adequate to prevent recurrence.

10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that applicable design bases are correctly translated into specifications, drawings, procedures, or instructions. It also requires that design control measures shall provide for verifying or checking the adequacy of the design, such as by the performance of design reviews.

In 1990, Plant Modification Request 02149 reduced the service water flow rate to the component cooling water heat exchangers to 8800 gpm. The supporting calculation for this design change, Calculation EG-06-W, Revision W3, dated July 6, 1990, described the service water flow rate to the component cooling water heat exchangers as 8800 gpm. However, Westinghouse Analysis FSDA-C-365, Revision 1, which determined the cooldown rate and time, used a service water flow rate of 13500 gpm to the component cooling water heat exchangers. The design control measures did not properly verify or check the adequacy of Calculation EG-06-W in that the assumed service water flow rates to the component cooling water heat exchangers were lower than those stated in the Westinghouse analysis. The failure to correctly translate the design basis into specifications and procedures was considered to be the first example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-482/9812-05).

E8.12 <u>(Closed) Inspection Follow up Item 50-482/97201-02</u>: Emergency Core Cooling System Leakage

a. <u>Background</u>

The NRC determined that there was no leakage acceptance criteria established for the emergency core cooling system as required by Regulatory Guide 1.139, "Guidance for Residual Heat Removal (RHR) to Achieve and Maintain Cold Shutdown," and referenced in Updated Safety Analysis Report, Table 5.4A-1. This issue was identified by the licensee's Design Basis/License Basis review team on November 5, 1997, and they initiated Performance Improvement Requests 97-3738, 97-3138, and 97-3563 to resolve the discrepancy.

The NRC also determined that Updated Safety Analysis Report, Table 5.4A-1, did not establish an acceptable leakage limit for residual heat removal operability. However, in Updated Safety Analysis Report, Section 18.3.4, and Technical Specification, Section 6.8.4, the licensee had established a program to reduce leakage from systems outside containment that contain highly radioactive fluids. Their program required monitoring and correcting leakages identified during surveillance tests or routine plant walkdowns. Their program met the requirement of Item III.D.1.1 of NUREG-0737. The licensee stated that the existing program met the intent of Regulatory Guide 1.139 and the Updated Safety Analysis Report table would be revised appropriately.

The licensee's corrective actions included the following:

- The licensee initiated Performance Improvement Requests 97-3138, 97-3563, and 97-3738 to resolve the discrepancy. The only licensing basis problems identified were:

  - Quantitive acceptance criterion was not included in the program for monitoring emergency core cooling system leakage outside of containment. This was a problem because a 1 gpm acceptance limit for emergency core cooling system leakage outside of containment was implied in the Safety Evaluation Report. The licensee stated that a 1 gpm acceptance limit is not and never was included in the technical specifications, although Technical Specification 6.8.4.a does provide a qualitative acceptance limit of "as-low-as-practical" as discussed in Updated Safety Analysis Report, Section 18.3.4, and NUREG 0881, Supplement 5.

  - Updated Safety Analysis Report Table 5.4A-1 (Sheet 8 of 10) stated that the licensee complied with Regulatory Guide 1.139. Regulatory Guide1.139 included the statement, "The leakage limits at which an RHR train is to be declared inoperable and isolated should be stated in the Plant Technical Specifications." The Safety Analysis Report contained a similar statement in Section 15.4.5.1. Technical Specification 6.8.4 required a program to maintain emergency core cooling system leakage outside of containment at as low as practical levels, but did not specify any quantitative acceptance limits at which equipment was to be declared inoperable and isolated.

- The licensee revised Procedure AP 25C-001, "WCGS Leak Reduction of Primary Coolant Sources Outside Containment," with Revision 1, which required a computation of total emergency core cooling system leakage with a 1 gpm acceptance criterion.

- The licensee revised Updated Safety Analysis Report, Table 5.4A-1 (Sheet 8 of 10), to state that residual heat removal leakage was addressed in the reactor coolant sources outside containment program as discussed in the technical specification and Updated Safety Analysis Report, Section 18.3.4.

- The licensee revised Procedures STN EJ-001, "Leakage Inspection of the RHR System," STN EN-001, "Leakage Inspection of the Containment Spray System," STN EM-001, "Leakage Inspection of the Safety Injection System," and STN BG-001, "Leakage Inspection of the Chemical and Volume Control System (CVCS)." These new procedures required performance of leak measurements with the applicable pumps running and quantification of all leaks. The new procedures were issued on June 3, 1998.

- The licensee revised Procedures STN PE-023, "TEN 02B Tank Pressure Test," Revision 3, STN PE-024, "TEJ01B Tank Pressure Test," Revision 3, STN PE-025, "TEJ01A Tank Pressure Test," Revision 3, and STN PE-026, "TEN02A Tank Pressure Test," Revision 3, on June 2, 1998. These procedures included a prerequisite requiring the performer to review Procedure AP 25C-001 requirements prior to starting the test. The liquid equivalent of the acceptance criteria for these procedures was now considered existing emergency core cooling system leakage that counts toward the 1gpm acceptance criteria contained in Procedure AP 25C-001.

b. Inspection Followup

The inspectors reviewed the revised procedures and revised Updated Safety Analysis Report, Table 5.4A-1. The inspectors determined that the corrective actions were appropriate to correct the discrepancy. The inspectors verified that the new procedures required performance of leak measurements as appropriate to calculate the required residual heat removal leakage. The acceptance criterion was 1 gpm. The inspectors noted that the licensee provided a quantitive acceptance criterion that was consistent with the "as-low-as-practical" requirement of the technical specifications.

E8.13 (Closed) Unresolved Item 50-482/97201-03: Residual Heat Removal Pump Operation in Minimum Recirculation Mode

a. Background

The NRC determined that for a small break loss-of-coolant accident,the residual heat removal pumps would start and operate on minimum recirculation flow for 2.5 hours before an operator action was necessary to either shut the pump down or initiate cooling flow to the residual heat removal heat exchanger. The NRC noted that this period of 2.5 hours exceeded the pump manufacturer's specified time limit of 30 minutes.

The NRC reviewed Calculation EJ-M-018, "RHR Pump Recirc. Operation vs. Time of Initiation of CCW flow to RHR Heat Exchanger," Revision 0. This calculation provided justification that the pumps could reliably operate in excess of 2.5 hours while in the recirculation mode. However, the team also noted that this calculation assumed an initial water temperature of 90 degrees F, whereas, Updated Safety Analysis Report, Table 3.11b, specified that the maximum residual heat removal water temperature was 104 degrees F. Based on the NRC finding, the licensee determined that sufficient margin existed in the calculation to demonstrate that the pump operation for 2.5 hours without any cooling water would not damage the pump with the 104 degrees F initial water temperature.

The licensee documented the corrective actions in response to the unresolved item in Performance Improvement Request 97-4150. The licensee's corrective actions included reviewing and revising Calculation EJ-M-018 as Revision 1, which changed the initial water temperature to 104 degrees F.

b. Inspection Followup

The inspectors reviewed Calculation EJ-M-018, Revision 1, and noted that the calculation was appropriately checked and verified. The inspectors also determined that the licensee's conclusions that a residual heat removal pump could be run for greater than 2.5 hours with 104 degrees F initial water temperature was valid.

The licensee's design control measures did not assure that specifications were correctly translated into the design for residual heat removal pump operation in the minimum recirculation mode. Calculation EJ-M-018 incorrectly assumed an initial water temperature of 90 degrees F in the residual heat removal system instead of a maximum design basis temperature of 104 degrees F to determine the adequacy of pump recirculation operation. The failure to translate the design data into Calculation EJ-M-018, was considered to be the second example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-482/9812-05).

E8.14 (Closed) Inspection Followup Item 50-482/97201-06: Procurement of Emergency Diesel Generator Relay

a. Background

The NRC reviewed three modification packages to evaluate the 10 CFR 50.59 safety evaluations and component procurement practices. The 10 CFR 50.59 evaluation conclusions were adequate, and the changes were consistent with the design basis. The team identified a concern with Design Change Package 05588, which in part, procured an over excitation relay for an emergency diesel generator. This component was installed as a safety-related item through the commercial grade dedication process conducted by the supplier. To maintain the relay's qualification, the team noted that monitoring of relay degradation was required, as specified in Certificate of Conformance 62152.1, to determine the extent of degradation and establish the relay replacement frequency. Documentation of the methodologies used to meet these requirements and the surveillance results could not be provided by the licensee during the inspection. The licensee issued Performance Improvement Request 98-0085 to address this issue.

b. Inspection Followup

The inspectors reviewed the following documentation: Certificate of Conformance 62152.1, I-ENG-014 (Electrolytic Capacitor PM Program), Performance Improvement Request 98-0085, "Material Code Inquiry 90702222," and assorted work packages and test records associated with the component. The inspectors also interviewed licensee personnel. The inspectors determined that the procedures an documentation existed at the time of the NRC inspection and adequately ensured t design basis for the component. In addition, the inspectors reviewed the test surveillances and determined them to be acceptable for ensuring operability of the emergency diesel generator relay.

E8.15 (Open) Inspection Followup Item 50-482/97201-07: Sizing of Class 1E Batteries.

a. Background

When determining the load profile of the batteries in Calculation NK-E-002, "Class 1E Battery Sizing," Revision 3, the licensee made some errors and omissions related to the magnitude and application of load currents in the load profile.

b. Inspection Followup

The licensee issued Performance Improvement Requests 97-3988 and 97-4063 to address these discrepancies. The team reviewed the performance improvement requests and determined that they were responsive to the concerns raised. This item will remain open pending completion of the corrective actions outlined in the performance improvement requests and subsequent NRC review.

E8.16 (Open) Inspection Follow up Item 50-482/97201-08: Sizing of Class 1E Batteries

a. Background

The licensee replaced the existing square cell Gould batteries with AT&T round cell batteries under Design Change Package 05846 in early 1996. Technical Specification 4.8.2.1 specified a criterion of 80 percent capacity for replacement of the Gould batteries, however, the inspectors were concerned that this criterion was not appropriate for determining degradation in the AT&T round cell batteries. In addition, inspectors noted that an aging factor of 1.25 in the formula used to determine battery cell size (Calculation NK-E-002, "Class 1E Battery Sizing," Revision 3) was omitted. As a result of this omission, the potential existed that the batteries were not oversized by 1.25 as required to offset a 20 percent deterioration that occurs at end of life. These issues were referred to the Office of Nuclear Reactor Regulation (NRR) for review.

b. Inspection Followup

Section 8.3.2.1.2 of the Updated Safety Analysis Report indicates that the batteries will be replaced when their capacity decreases below 80 percent of the manufacturer's rating in accordance with IEEE 450-1975. This capacity is determined by subjecting the battery to a performance discharge test every 60 months pursuant to Technical Specification 4.8.2.1.e, or every 18 months for a degraded battery pursuant to Technical Specification 4.8.2.1.f. These technical specifications were developed based on the operating characteristics of the Gould batteries. As a rule, rectangular cell batteries, such as the Gould batteries, are relatively stable throughout most of their life, but experience a gradual capacity loss with age, with replacement recommended at 80 percent capacity. As such, the Gould batteries were sized using a 1.25 aging factor to ensure continued operability of the batteries.

The operating characteristic of the AT&T round cell batteries currently installed at Wolf Creek differ from the Gould batteries in that they experience a gradual capacity increase over time. As such, an aging factor of 1.0 is used when sizing the batteries in lieu of 1.25. Based on the above, the gradual decline in capacity that was expected for the Gould batteries as they age would be abnormal if observed on the AT&T round cell batteries. Therefore, a technical specification surveillance test acceptance criterion of 80 percent capacity is not appropriate for the AT&T round cell batteries, since a reduction in capacity would be indicative of abnormal battery performance.

The licensee indicated that it intends to pursue an update to the Wolf Creek technical specification through the standard technical specification conversion process to reflect appropriate acceptance criteria for the AT&T round cell batteries. NRR found this approach to be acceptable.

In addition, Updated Safety Analysis Report section 8.3.2.1.2 states, ". . . a margin of 25 percent is applied to ensure that the rated battery capacity is at least 125 percent of that required. This margin is consistent with the 80 percent capacity battery replacement criteria given in IEEE 450-1975. As a result of the above sizing, the WCGS batteries are selected from those larger sizes that are commercially available. The resulting final battery selection is in excess of 150 percent of the system requirements." This issue remains open pending for further review of the licensee corrective actions.

E8.17 <u>(Open) Inspection Followup Item 50-482/97201-09</u>: Sizing of Class 1E Batteries

a. <u>Background</u>

The licensee replaced the existing square cell batteries with AT&T round cell batteries under Design Change Package 05846. However, sized the new batteries based on the 25 percent margin stated in the Updated Safety Analysis Report. However, Section 8.3.2.2 of the NRC's Safety Evaluation Report was based on a battery capacity oversizing margin of 50 percent. This issue was referred to NRR for review and resolution.

b. <u>Inspection Followup</u>

In addition to correction factors for temperature and design margins, the Gould batteries were sized using an aging factor of 1.25 to account for loss of battery capacity as they age. The AT&T batteries were sized using a temperature correction factor of 1.085, a design margin of 1.25 and an aging correction factor of 1.0, since the round cell batteries are not designed to lose capacity as they age.

NRR reviewed the licensee's calculations for sizing the AT&T round cell batteries and identified that battery NK11, the battery that possesses the least amount of margin, was purchased with an additional margin 23 percent of system requirements. As such, NRR concluded that the AT&T round cell batteries are adequately sized to perform their safety function however it was noted that battery NK11 is not sized with 150 percent of the system requirements as stated in the Wolf Creek Updated Safety Analysis Report. The licensee plans to revise Calculation NK-E-002, "Class 1E Battery Sizing." This issue remains open pending review of calculation NK-E-002 and the licensee's corrective actions.

E8.18 (Open) Unresolved Item 50-482/97201-10: DC Load Flow and Voltage Drop

a. Background

Calculation NK-E-001, "Class 1E DC Voltage Drop," Revision 1, made an assumption that a minimum operating voltage of 100 V was used for components where a minimum had not been specified by the manufacturer.

b. Inspection Followup

The licensee issued Performance Improvement Requests 97-4180 and 97-4043 to address the issue. Performance Improvement Request 97-4043 attempted to link all components listed at 100 V minimum to ANSI and ICS Standards stipulating the same values based on SNUPPS requirements. The team was concerned that this resolution was too general since some of the components may not have been designed to the referenced standards even though this was a SNUPPS requirement. The licensee indicated that they were also utilizing an alternate approach that links components to the standards by comparison of similar representative components, when implementing the performance improvement requests. The team considered the alternate approach to be satisfactory.

The item will remain open pending completion of corrective actions by the licensee.

E8.19 (Open) Unresolved Item 50-482/97201-11: DC Load Flow and Voltage Drop

a. Background

In reviewing Calculation NK-E-001, "Class 1E DC Voltage Drop," Revision 1, and Calculation NK-E-002, "Class 1E Battery Sizing," Revision 3, it was observed that the calculations did not reflect the worst case minimum voltage for each battery.

b. Inspection Followup

The licensee issued Performance Improvement Request 97-4185 to address these discrepancies. The team reviewed the performance improvement request and determined that it satisfactorily addressed the concerns identified. Calculation NK-E-001 will be revised first and data from this calculation will be entered in Calculation NK-E-002.

This item will remain open pending completion of the licensee's corrective actions.

E8.20 (Open) Unresolved Item 50-482/97201-12: DC Load Control

a. Background

In reviewing Procedure A1-05-006, "Electrical Load Growth," Revision 0, it was noted that dc electrical load growth was not always maintained in accordance with the requirements of the procedure, and that a number of discrepancies existed in the data base.

b. Inspection Followup

The licensee issued Performance Improvement Requests 97-4123, 97-4125, and 97-3846 to address the identified shortcomings. The team reviewed the performance improvement requests and determined that they were responsive to the issues identified.

This item will remain open pending completion of the licensee's corrective actions.

E8.21 (Closed) Unresolved Item 50-482/97201-13: Acceptance Criteria for Battery Test
(Closed) Unresolved Item 50-482/97201-14: Corrective Action For Battery Test

a. Background

The NRC reviewed surveillance procedures for the safety-related batteries. During this review it was found that the only acceptance criteria for Surveillance Test Procedure MT-021, "Service Test for 125 VDC Class 1E Batteries," Revision 10, was that the test be successfully completed. Also it was noted that the surveillance test did not incorporate the design basis requirements contained in Calculation NK-E-002, pertaining to whether the battery discharge current was consistent with the load profile and whether the battery final terminal voltage was higher than the minimum allowable design value for the battery being tested. Furthermore, the acceptance criteria for Step 6.1 of Procedure MT-022, "5 Year 125 VDC Discharge Battery Test," Revision 9, did not specify that a constant discharge rate be maintained until battery terminal voltage fell to a value equal to the minimum specified average voltage per cell or 105 volts for 60 cells. In addition, neither procedure provided the needed corrective actions for test deviations from the acceptance criteria.

b. Inspection Followup

The inspectors reviewed documents and procedures and interviewed personnel to determine the adequacy and completeness of the licensee's corrective actions. The licensee issued Performance Improvement Requests 97-3989 and 3941 which identified the need to revise and clarify Procedures STS MT-021 and STS MT-022. The inspectors reviewed these performance improvement requests and Procedures STS-MT-021, "Service Test for 125vdc Class 1E Batteries," Revision 11, STS-MT-022, "Service Test for 125vdc Discharge Battery Test," Revision 10, Calculations NK- E-001, "Class 1E DC Voltage Drop," Revision 1, and NK-E-002, "Class 1E Battery Sizing," Revision 3. The revised calculations and the performance improvement requests were determined to be thorough and comprehensive. The inspectors also reviewed a licensee performed analysis that determined that the battery met the technical specification operability requirements. The inspectors noted that the acceptance criteria, and corrective actions taken for test deviations were placed into the respective battery tests. As the result of this review, the inspectors determined that no operability problem with the batteries existed.

The inspectors determined that the acceptance criteria for station battery surveillance test procedures were not appropriate to the circumstances in that the procedure acceptance criteria did not assure that battery discharge current was consistent with the load profile, that the battery final terminal voltage was greater than the minimum allowable design value, and that a constant discharge rate was maintained during testing. This failure to implement appropriate acceptance criteria was considered to be an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (50-482/9812-02).

E8.22 (Closed) Unresolved Item 50-482/97201-15: Refueling Water Storage Tank Level Instrumentation

a. Background

The NRC reviewed Calculation SA-90-056, "Reactor Protection System ESFAS Channel Error Allowances," Revision 0, which calculated the refueling water storage tank level instrument loop uncertainty. As the result of this review, the NRC identified that the licensee did not consider density variation due to temperature and boron concentration in determining the refueling water storage tank level instrument loop uncertainties. As a result, the Low-Low Level 1 switchover set point could reduce the available tank volume by 3.24 percent, the Low alarm set point could be reduced 2.51 percent and the tank empty alarm could drift down 14 inches to within 3 inches of the refueling water storage tank suction line. These uncertainties would reduce the margi available to the operators to respond to the event. The NRC reviewed Letter SLNRC 84-0089, dated May 31, 1984, which the licensee sent to the NRC justifying the use of indicated readings without regard for instrument uncertainties to satisfy technical specification surveillance requirements. The licensee could not find documentation of the NRC's acceptance of the licensee's position. However, a preliminary evaluation performed by the licensee indicated that there was an adequate margin in the net-positive suction head analysis to compensate for level indication inaccuracies.

The NRC reviewed Calculation BN-20, "Refueling Water Storage Tank Set Points," Revision 1, which assumed instrument inaccuracies of 1 percent for bistable and 3 percent for total loop error to establish the refueling water storage tank level set points. The licensee was not able to produce uncertainty calculations supporting these assumptions. However, as the result of the team's review of the licensee's preliminary analysis of these discrepancies, the team determined that no operability issue existed.

b <u>Inspection Followup</u>

The inspectors reviewed Performance Improvement Request 973974, dated December 4, 1997, which the licensee initiated to review the density variation due to temperature and boron concentration in the refueling water storage tank instruments. The licensee identified that new calculations were required to determine total loop uncertainty for the alarm set point, level indication and the computer point. The team reviewed the new Calculation BN-J-001, "Refueling Water Storage Tank Level Transmitter Density Errors," Revision 0, which was prepared to determine the magnitude and direction of errors due to density variations in the borated water contained in the tank. The team determined that the licensee was in the process of preparing two additional calculations to determine and document the inaccuracies for other bistables and loop uncertainties, and set points for other functions. In addition, the licensee stated that they would revise Calculation SA-90-056 to incorporate the density variation due to temperature and boron concentration.

The inspectors reviewed the licensee's Letter SLNRC 84-0089 dated May 31, 1984. This letter discussed the use of indicated readings without regard for instrument uncertainties to satisfy technical specification surveillance requirements. The subject matter was discussed with the NRC program office. As the result of these discussions, the inspectors determined that the NRC had accepted the licensee's position regarding the use of indicated instrument readings without instrument uncertainties to satisfy technical specification surveillance requirements.

Design control measures did not ensure that the refueling water storage tank level instrumentation uncertainty Calculation SA-90-056, "Reactor Protection System ESFAS Channel Error Allowances," Revision 0, which calculated the Low-Low Level 1 set point for the refueling water storage tank, correctly translated errors from density variation due to temperature and boron concentration in determining the refueling water storage tank level instrument uncertainty. In addition, uncertainty calculations did not exist for the instrument inaccuracies of 1 percent for bistables and 3 percent for total loop error which were assumed in Calculation BN-20, "Refueling Water Storage Tank Set Points," Revision 1. The inspectors determined that the failure to include density variations due to temperature and boron concentrations in the refueling water storage tank level calculations and the failure to have calculations for the uncertainties associated with bistable and total loop error was the third example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-482/9812-05). The licensee's planned corrective actions appeared comprehensive and appropriate to prevent recurrence.

E8.23 <u>(Closed) Unresolved Item 50-482/97201-16</u>: Seismic Qualification

a. Background

The NRC determined that the licensee's design control measures appeared to not verify or check the adequacy of the residual heat removal pump suction Pressure Gages PI-601 and PI-602, to ensure that these gages would operate satisfactorily during a seismic event.

In response to the NRC finding the licensee stated that their Ashcroft Model 1279 pressure indicators (installed as PI-601 and 602) were supplied by Westinghouse along with other indicators under their Specification Sheet 04610 in the mid-1980 time frame. Furthermore, the licensee stated that items on this specification sheet were manufactured by Ashcroft as commercial grade items with no unique nuclear requirements. Westinghouse supplied them to Wolf Creek under the program they had in place at the time. The program, as documented in a Westinghouse letter dated July 10, 1989, included an engineering judgement by Westinghouse regarding the seismic and pressure boundary integrity of the indicators.

During the latter part of the 1980's, the nuclear industry developed the concept of a "commercial grade" item and the documentation to be provided in the future to dedicate such items for use in nuclear safety-related applications, such as residual heat removal pump suction Pressure Gages PI-601 and PI-602. At this time, the licensee questioned the documentation available onsite to substantiate the Westinghouse seismic integrity engineering judgement for the Ashcroft indicators. The licensee stated that this was strictly an effort to upgrade the information available onsite, and did not reflect any concern that the indicators could not withstand a seismic event. In fact, the licensee noted that other similar Ashcroft 1279 Pressure Indicators, that had been supplied by Bechtel under their Specification J-515A(Q), had been provided with a seismic qualification report. Westinghouse provided the licensee with Letter RCS/CIEI(89)-299, dated July 10, 1989, which provided the bases for the seismic qualification of the pressure indicators.

In mid-1991, the licensee decided to have a review performed to compare the Bechtel Specification J-515A(Q) seismic qualification report envelop against the three possible configurations supplied by Westinghouse (diaphragm seal only, snubber only, neither diaphragm seal nor snubber). The licensee stated that this review was not done because there was a concern as to the seismic acceptability of the pressure indicators, but rather to address the use of dedicated commercial grade items. The review was completed for Calculation XX-F-010, "Seismic Qualification of Ashcroft Model No. 1279," dated August 29, 1991, and formally issued on January 21, 1998. The licensee stated that this review supported seismic qualification and exceeded the requirements for commercial item dedication. The purpose of the calculation was to provide seismic qualification and justification to indicate that the Ashcroft Model 1279 pressure indicators in accordance with Specification Sheet 04610, Revision 1, supplied by Westinghouse, were similar to those of Specification J-515A, supplied by Bechtel. The license stated that this review included all the safety-related pressure indicators furnished under Specification Sheet 04610, and not just the PI 601/602 pressure indicators.

b. Inspection Followup

The inspectors noted that the licensee considered the residual heat removal pump suction pressure indicators to have both a pressure integrity and a seismic design safety function. The inspectors reviewed the Calculation XX-F-010, and the documentation concerning the two pressure indicators and determined that there was no measurable difference between the two pressure indicators. The inspectors also verified that Calculation XX-F-010, provided a seismic qualification of the Ashcroft Model 1279 pressure indicators. The licensee again indicated that they had no concern regarding the seismic qualification of the Ashcroft Model 1279 indicators. This position was based on the Westinghouse's letter of July 10, 1989 ,and later by Calculation XX-F-010. Furthermore, this was supported by Bechtel's seismic qualification report of Ashcroft Model 1279 pressure indicators.

E8.24 (Closed) Unresolved Item 50-482/97201-17: Nitrogen Bottle Installation

a. Background

During a refueling outage, the NRC determined that nitrogen bottles, temporarily installed in the residual heat removal heat exchanger rooms and fastened to steel structures by No. 9 wire, were not seismically restrained and could cause a potential missile hazard. The licensee stated that those nitrogen bottles were installed in accordance with Procedure GEN 00-007, "RCS Drain Down Procedure," Revision 19, to provide backup nitrogen for the residual heat removal heat exchanger outlet valve operators (EJHCV-606 and 607) during the refueling outage. The NRC team identified that a safety evaluation was not performed in accordance with 10 CFR 50.59 to provide a basis for determining that an unreviewed safety question was not involved for the installation of nitrogen bottles in the residual heat removal pump rooms.

Since these bottles were removed at the end of the refueling outage, the licensee and the NRC concluded that this condition did not constitute an operability concern. The licensee documented the corrective actions to this issue using Performance Improvement Request 97-3961. The licensee revised Procedure GEN 00-007 and developed a 10 CFR 50.59 safety evaluation. The licensee concluded that the nitrogen bottle installation was not an unreviewed safety question.

b. Inspection Followup

The inspectors reviewed the safety evaluation and Procedure GEN 00-007, "RCS Drain Down," Revision 28, dated April 1, 1998. The inspectors observed that the licensee changed the procedure to ensure that the appropriate restraints were used when installing the nitrogen bottles. However, the inspectors also observed that the procedure did not state where the bottles would be placed in the residual heat removal heat exchanger rooms. The licensee revised Procedure GEN 00-007 on June 23, 1998, to include the correct nitrogen bottle location.

The inspectors noted that neither this nitrogen bottle installation nor a procedure that described the nitrogen bottle installation was described in the Updated Safety Analysis Report. Since this change did not change the facility as described in the Updated Safety Analysis Report, a 50.59 safety evaluation was not required.

E8.25 <u>(Closed) Unresolved Item 50-482/97201-18</u>: Motor-Operated Valve Differential Pressure

a. <u>Background</u>

The NRC evaluated the adequacy of the component cooling water containment isolation valves to meet their design basis requirement by reviewing the motor-operated valve design documents. These valves are required to close against reactor coolant pressure resulting from a reactor coolant pump (RCP) thermal barrier break. During this review, the team observed that during the design basis accident involving a rupture of the RCP thermal barrier, the differential pressure against which Valves EG-HV-062 and -132 must close was calculated to be 1120 psid. This result was based on a nonconservative assumption that the downstream pressure used in the calculation was an average of the pressure before and after closure. This caused the downstream pressure to be unrealistically high and consequently the experienced differential pressure to be low. The team determined that the downstream pressure would be 22 psig (based on the static head of the component cooling water surge tank) and the differential pressure for closure would be 2228 psid. The licensee initiated Performance Improvement Request 97-4054 to resolve this issue. The licensee also performed a review and determined that the only other valves affected were Valves BB-HV-0013/14/15/16. However, these valves are closed on limit switch control in lieu of torque switch control and therefore did not have a similar problem.

b. <u>Inspection Followup</u>

The inspectors reviewed documents, procedures, and interviewed personnel to determine the adequacy and completeness of the licensee's corrective actions. The inspectors specifically reviewed the following documents: Performance Improvement Request 97-4054, Calculations EG-M-006, -007, and -012 (bounding conditions for motor-operated valves), all Revision 3. The NRC determined that Calculation E-025-00007(Q)-W10, "MOV Design Configuration Document," Revision 9W, incorrectly identified the differential pressure to close component cooling water Valves EG-HV-062 and -132 as 1120 psid instead of 2228 psid. The reason for the error was due to assuming a nonconservative downstream pressure of 1130 psig instead of 22 psig based on the static head of the component cooling water surge tank. The inspectors noted that there was no operability concern because the licensee's analysis demonstrated that the motor-operated valves had sufficient thrust to close the valves against the required differential pressure.

While the inspectors agreed with the licensee's conclusions and corrective actions for this item, the inspectors determined that the licensee's design control measures did not assure that the component cooling water motor-operated valve design bases were correctly translated into the design calculations. The failure to translate the required design basis differential pressure specified for the component cooling water motor-operated valve was the fourth example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-482/9812-05). The licensee's corrective actions appeared to be comprehensive and adequate to prevent recurrence.

E8.26 (Closed) Unresolved Item 50-482/97201-19: Component Cooling Water Low Temperature

a. Background

The NRC reviewed Design Change PMR 4380, "Component Cooling Water Temperature Change," Revision 2, and its associated safety evaluation. The NRC noted that this design change revised the allowable component cooling water temperature from 60 to 32 degrees F. The design change assumed that the component cooling water system was at the same temperature as the lake water when the lake was at 32 degrees F. The NRC identified that two items were not adequately addressed in the design change package or in the safety evaluation.

The NRC determined that the lower component cooling water temperature caused lower lubricating oil temperature for several motors, resulting in higher power requirements. The increased emergency diesel generator loading was not addressed in either the modification or the safety evaluation. However, the NRC concluded that there was no operability concern since the loading increase was small and the diesel generator had a large loading margin.

The NRC also determined that the lower component cooling water temperature resulted in a lower spent fuel pool water temperature. The lower spent fuel pool temperature effect on reactivity was not addressed in either the modification or the safety evaluation. The NRC noted that the minimum temperature for which the spent fuel pool reactivity was analyzed was 60 degrees F. The licensee stated that the spent fuel pool temperature could approach within 4 degrees F (i.e., 36 degrees F) of the component cooling water temperature. The licensee issued On-the-Spot Change 97-0898 To Procedure CKL ZL-003, "Control Room Daily Readings," which placed an administrative limit of 65 degrees F on the minimum spent fuel pool temperature until a reactivity analysis at lower temperatures was completed. Subsequent to the inspection, the licensee completed an analysis which determined that lowering the spent fuel pool temperature from 60 to 35 degrees F would reduce the reactivity in the spent fuel pool. In addition, the licensee determined that the lower temperature had no adverse effect on the solubility of boron because the spent fuel pool boron concentration of 2000 to 2500 ppm was well below the saturation curve at 35 degrees F.

The NRC determined that the licensee's safety evaluation did not completely verify the absence of an unreviewed safety question since it did not address the effect of low temperature on the spent fuel pool reactivity and did not evaluate the effects on the diesel generator loading caused by the lower component cooling water temperature.

b. Inspection Followup

The inspectors reviewed Performance Improvement Request 973978, dated December 4, 1997, which the licensee generated to resolve the issue of the increase in power required to run the safety-related pumps when component cooling water temperature was 32 degrees F. The licensee determined that the net increase on the diesel generator load per train was 24 kW. The inspectors noted that the most limiting safety-related load on the emergency diesel generator occurred during the recirculation phase and was equal to 5260 kW. The maximum load of 5834 kW including safety and nonsafety-related loads occurred during a station blackout event. The inspectors noted that each generator was rated at 620 kW for continuous operation, therefore, no operability concern was identified. The inspectors determined that there was adequate margin to meet the additional demand. The inspectors reviewed the revised 10 CFR 50.59 safety evaluation and found that the licensee included a discussion of the increase in power to run the safety-related pumps and the effect on the diesel generator. The inspectors noted that the licensee concluded that the lowering of the component cooling water temperature which caused an increase in power demand to run the safety-related pumps was not an unreviewed safety question. The inspectors agreed with the licensee's evaluation.

The inspectors reviewed Performance Improvement Request 974062, dated December 12, 1998, which was initiated to determine the effect of low component cooling water temperature on the spent fuel pool reactivity. In addition, the licensee prepared a 10 CFR 50.59 safety evaluation, dated January 14, 1998, to determine the acceptability of revising the Updated Safety Analysis Report to reflect allowing the spent fuel pool temperature to go as low as 35 degrees F. The effects of the lower temperature on reactivity and boron solubility were evaluated as a result of the change to the Updated Safety Analysis Report. The inspectors found that the effect of the temperature change on reactivity was that it added conservatism by resulting in a net negative reactivity addition. Based on the increase in negative reactivity being added to the spent fuel pool, the licensee stated there were no credible accidents created by the change. The licensee further stated that the criticality analysis in the Updated Safety Analysis Report was conservative in that this analysis assumed no boron in the water, while the pool boron concentration was maintained at or above 2000 ppm.

While the inspectors agreed with the licensee's conclusions and corrective actions for this item the inspectors determined that the licensee's design control measures did not assure that the effects of the lower component cooling water water temperatures on the spent fuel pool reactivity were correctly translated into design Change PMR 4380. The failure to translate the lower component cooling water water temperatures into the design bases was the fifth example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-482/9812-05). The licensee's corrective actions appeared to be comprehensive and adequate to prevent recurrence.

E8.27 (Closed) Unresolved Item 50-482/97201-20: Corrective Action for Component Cooling Water Operating Procedure

a. Background

The NRC determined that the licensee's Updated Safety Analysis Report, Section 9.2.2.2.3, stated that during a cooldown, component cooling water flow to the spent fuel pool heat exchanger was reduced or terminated within 4 hours after shutdown. However, the licensee's operating procedures did not specifically inform the operator to reduce component cooling water flow to the component cooling water heat exchanger four hours after shutdown to assure adequate flow to the remaining equipment cooled by component cooling water. The licensee identified in performance improvement request 95-1167 dated May 1995, that this design basis requirement was not incorporated in Operating Procedures EJ-120, "Start of a Residual Heat Removal (RHR) Train," Revision 32, and EJ-121, "Start of a RHR Train in Cooldown Mode," Revision 11.

As corrective action to Performance Improvement Request 95-1167, the licensee changed the procedures to provide better agreement with the Updated Safety Analysis Report. In addition, the Updated Safety Analysis Report Section was revised to be compatible with the paragraphs in Procedures EJ-120 and EJ-121. However, upon review of these procedures, the NRC noted that the Updated Safety Analysis Report and the affected procedures were still not in agreement. Specifically, the licensee's operating procedures did not inform or direct the operator to reduce the component cooling water flow to the component cooling water heat exchanger four hours after shutdown.

The licensee initiated Performance Improvement Request 97-3887 on November 24, 1997, to readdress the issue of specifically directing operators to reduce the component cooling water flow to the component cooling water heat exchanger four hours after shutdown. The licensee initially believed that the applicable residual heat removal system procedures could be changed to reflect what the Updated Safety Analysis Report stated in regards to reducing the component cooling water flow after shutdown. After further review, the licensee determined that the need to reduce the component cooling water flow was based on 90 degree F lake temperature. The licensee considered that adding this Updated Safety Analysis Report requirement to the residual heat removal system procedures could cause operator confusion due to the fact that lake temperature seldom approaches 90 degrees F. The licensee determined that an Updated Safety Analysis Report change should be made to clarify the Updated Safety Analysis Report statement. The clarification would provide background information that would aid in the operation of the component cooling water system. The residual heat removal system procedures would be revised once the Updated Safety Analysis Report change was finalized.

The licensee's corrective actions were as follows:

- Updated Safety Analysis Report Change Request 98-048 and associated unreviewed safety question were approved by the plant safety review committee on April 22, 1998, which clarified the Updated Safety Analysis Report on the need to isolate the component cooling water flow to the component cooling water heat exchanger. The Updated Safety Analysis Report was changed identifying that if the component cooling water heat exchanger outlet temperature exceeded 120 degrees F during shutdown and cooldown, the component cooling water flow to the component cooling water heat exchanger was to be reduced or terminated.

- Procedure STS EJ-120, "Startup of a Residual Heat Removal Train," Revision 33 added Step 4.10 to ensure component cooling water cooling was isolated to the component cooling water heat exchanger if component cooling water outlet temperature exceeded 120 degrees F.

- Procedure STS EJ-121, "Startup of a RHR Train in Cooldown Mode," Revision 12, added Step 4.9 to ensure component cooling water cooling was isolated to the component cooling water heat exchanger if component cooling water outlet temperature exceeds 120 degrees F.

b. Inspection Followup

In 1995, the licensee initiated Performance Improvement Request 95-1167 to identify that this requirement as stated in the Updated Safety Analysis Report, had not been incorporated in Operating Procedures EJ-120, and -121. The licensee changed both procedures and the Updated Safety Analysis Report, Section 9.2.2.2.3, but failed in 1995 to correct a discrepancy regarding specific isolation instructions for the component cooling water heat exchanger.

The NRC identified that clarification of the Updated Safety Analysis Report, Section 9.2.2.2.3, was needed to address consideration of the lake temperature to determine when the component cooling water flow had to be reduced or terminated.

The licensee initiated Performance Improvement Request 97-3887, to readdress this issue. In addition, procedure changes in Procedures STS EJ-120 and -121 were initiated which detailed new steps ensuring component cooling water cooling was isolated to the component cooling water heat exchanger if component cooling water outlet temperature exceeded 120 degrees F. The licensee also initiated Updated Safety Analysis Report, Change Request 98-048, which clarified the Updated Safety Analysis Report on the need to isolate the component cooling water flow to the component cooling water heat exchanger on April 22, 1998. The Updated Safety Analysis Report was revised to identify that if the component cooling water heat exchanger outlet temperature exceeded 120 degrees F, the component cooling water flow to the component cooling water heat exchanger was to be reduced or terminated.

10 CFR Part 50, Appendix B, Criterion XVI, requires that procedures be established to assure that conditions adverse to quality are promptly identified and corrected. The failure to promptly correct a discrepancy regarding the component cooling water cooling flow isolation to the component cooling water heat exchanger during cooldown was a violation of 10 CFR Part 50, Appendix B, Criterion XVI. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC enforcement policy (50-482/9812-06).

E8.28 (Open) Unresolved Item 50-482/97201-21: Updated Safety Analysis Report Discrepancies

a. Background

The NRC team identified the following Updated Safety Analysis Report discrepancies:

- Different values were referenced for the refueling water storage tank water volumes in the documents listed below.

- Updated Safety Analysis Report Section 6.3.2.2 (page 6.3-6) stated that the minimum refueling water storage tank volume "available" or "assured" for emergency core cooling system injection mode operation was 394,000 gallons. Another paragraph in the same Updated Safety Analysis Report section refers to "usable" volume. However, Technical Specification 3/4.5.5 specified the 394,000 gallons as the minimum contained water volume.

- Updated Safety Analysis Report Table 6.3-1 listed 419,000 gallons as maximum volume, 407,000 gallons as normal capacity, and 394,000 gallons as assured water volume. These three refueling water storage tank volumes are also shown in Updated Safety Analysis Report, Figure 6.3-7, and System Description M-10BN(Q), Figure 1.

- Updated Safety Analysis Report Table 6.2.1-5 listed refueling water storage tank water volume of 370,000 gallons for containment analysis.

- Updated Safety Analysis Report, Table 6.3-10, listed 326,860 gallons as refueling water storage tank volume for emergency core cooling system cooling.

• NUREG-0881 (Wolf Creek), Section 8.3.2.1.2, refers to the same section in NUREG-0830 (Callaway) for a discussion of the NRC staff's position on battery capacity. That section of NUREG-0830 stated that the licensee revised the Updated Safety Analysis Report in Revision 6 to state that batteries were sized in excess of the 50 percent margin required. Callaway Updated Safety Analysis Report was revised, but the Wolf Creek's Updated Safety Analysis Report had not been revised to reflect similar changes.

• Updated Safety Analysis Report Section 9.2.2.2.2 states, "The normally closed parallel sets of containment isolation valves will allow the operator to establish cooling water to the reactor coolant pumps and the excess letdown heat exchanger under emergency conditions, with a single failure." However, Updated Safety Analysis Report, Table 3-11(B)-3, listed the motor operators for these valves as Category C, EQ not required. The currently installed motor operators are Class RH, that is, environmentally qualified and, therefore, there was no operability concern.

• Calculation EG-06-W, "Component Cooling Water System Calculation," Revision W-3, determined that the component cooling water heat exchanger heat transfer coefficient was 190 Btu/hr-ft^2-F based on the revised essential service water flow of 7150 gpm. The Updated Safety Analysis Report stated that the transfer coefficient was 193 Btu/hr-ft^2-F.

- Calculation SA-89-017, "Evaluation of CCW & RHR Heat Exchanger Performance for the Extended Fuel Operating Cycle (18 Months)," Revision 0, determined that component cooling water temperature reaches 126 degrees F. However, Updated Safety Analysis Report, Table 9.2-11, was based on a component cooling water temperature of 120 degrees F.

- Updated Safety Analysis Report Fig. 5.4-8 showed suction for residual heat removal Pumps A and B as coming from RCS hot-leg Loop 4, whereas, System Description M-10EJ(Q) and P&ID M-12EJ01 showed Loop 1 for Pump A and Loop 4 for Pump B.

- Updated Safety Analysis Report Section 6.3.5.3, "Flow Indication," stated that the flow from each residual heat removal subsystem to the RCS cold legs was recorded in the main control room. This contradicted Updated Safety Analysis Report, Table 7.5-1, and P&ID M-12JE01 (Loop FT-988), which showed this parameter as being indicated (instead of recorded) in the main control room. The licensee issued Performance Improvement Request 97-4179 to update the Updated Safety Analysis Report.

- Updated Safety Analysis Report, Table 7A-3, showed a range of 0-60 psig for the containment pressure gauge, whereas, the range of the installed gauge was 0-69 psig.

- Updated Safety Analysis Report, pages 6.3-6, 9.2-43, 9.2-45, and 9.2-48 incorrectly described the control function of the refueling water storage tank auxiliary steam heating system with respect to winterization Procedure STN GP-001.

- Updated Safety Analysis Report Section 8.3.2.1.2 stated that a Class 1E battery was to supply the loads in Tables 8.3-2 and 8.3-3 for 200 minutes where it should be for 240 minutes.

- Updated Safety Analysis Report, Section 7.4.1, states that the refueling water storage tank level transmitters are required for safe shutdown. However, Updated Safety Analysis Report, Table 3.11(b)3, does not list these transmitters as required for hot or cold shutdown.

The above discrepancies had not been corrected and the Updated Safety Analysis Report updated to assure that the information included in the Updated Safety Analysis Report contained the latest material as required by 10 CFR 50.71(e).

b. <u>Inspection Followup</u>

- The licensee initiated Performance Improvement Request 97-4018 to address the refueling water storage tank water volume inconsistencies in the Updated Safety Analysis Report, technical specifications, and system description. The licensee will review and implement the appropriate document changes in response to this issue.

- The licensee initiated Performance Improvement Request 98-0618 to address the battery capacity issue. The licensee will review and implement the appropriate document changes in response to this issue following resolution of Unresolved Item 50-482/97201-09, Battery Sizing.

- The licensee documented the corrective actions for the component cooling water containment isolation valve qualification issue in Performance Improvement Request 97-4126. The corrective actions included performing calculation, EG-M-032, "CCW Heat Exchanger Performance," Revision 0, to provide a basis for revisions to the Updated Safety Analysis Report and component cooling water system description. The licensee implemented the Updated Safety Analysis Report changes with Updated Safety Analysis Report Change Request 98-037.

- The licensee stated that the component cooling water heat exchanger heat transfer coefficients were different because the 190 Btu/hr-ft^2-F value assumed that the maximum heat exchanger tubes were plugged. This value was then used to determine if the component cooling water water temperature going to the components cooled by the component cooling water system was below the maximum allowed value. The licensee determined that the water temperature would be within the required limits.

  The 193 Btu/hr-ft^2-F value was used to determine the maximum heat load that the component cooling water heat exchangers would discharge to the ultimate heat sink. The licensee determined that the ultimate heat sink would not exceed any design temperature limits based on this heat transfer coefficient. Although the two heat transfer coefficients were different, they were used as conservative values in different calculations. No Updated Safety Analysis Report change was required.

- The licensee documented the corrective actions for the component cooling water heat exchanger outlet temperature discrepancy in Performance Improvement Request 97-4052. The licensee reperformed Calculation EG-M-032, "CCW Heat Exchanger During Normal Operations, Shutdown @ Four Hours (and 12 hours), and Post-LOCA Recirculation," Revision 0. The calculated maximum component cooling water heat exchanger outlet temperature was 126.8 degrees F, which was below the allowed upper limit of 130 degrees F. The value of 130 degrees F was then used as a basis in Calculation EG-06-W, "Component Cooling Water System," Revision 4. Based on the results of the calculations, Updated Safety Analysis Report, Table 9.2-11, was revised using Updated Safety Analysis Report CR 98-069, to be consistent with the results of Calculation EG-M-032.

- The licensee documented the corrective actions for the residual heat removal pump loop suction location discrepancies in Performance Improvement Request 97-3823. The licensee determined that the residual heat removal Pump A suction was from Loop 1 and not Loop 4 as shown in Updated Safety Analysis Report, Figure 5.4-8. The licensee corrected the figure using Updated Safety Analysis Report Change Request 98-010.

- The licensee documented the corrective actions for the residual heat removal system control room indication discrepancies in Performance Improvement Request 97-4179. The corrective actions included reviewing the residual heat removal system description, piping and instrument diagrams, and Updated Safety Analysis Report, Section 6.3.5.3. The licensee determined that the only discrepancy was that the paragraph title in Updated Safety Analysis Report, Section 6.3.5.3, was incorrect which resulted in a misinterpretation of the Updated Safety Analysis Report. The title was changed to "RHR Pump Cold Leg Injection Flow" from "RHR Pump Hot Leg Injection Flow." The licensee corrected the paragraph title using Updated Safety Analysis Report Change Request 98-010.

- The licensee documented the corrective actions for the difference in the containment pressure gage actual range and the range listed in Updated Safety Analysis Report Table 7A-3 in Performance Improvement Request 98-0062. The licensee determined that the Updated Safety Analysis Report table was incorrect. The licensee changed the Updated Safety Analysis Report table using Updated Safety Analysis Report Change Request 98-010.

- On February 21, 1997, the licensee documented the refueling water storage tank heating steam control function issue in Performance Improvement Request 97-0547 when identified by the system engineer. On March 27, 1997, the licensee reviewed the issue and implemented changes to the affected documents. In addition, on December 30, 1997, the licensee approved Updated Safety Analysis Report Change Request 97-044 to correct the heating steam control function descriptions.

- The licensee initiated Performance Improvement Request 97-4190 to address the battery load supply time issue. The licensee will review and implement the appropriate document changes in response to this issue following resolution of Unresolved Item 50-482/97201-07, Battery Load Profile.

- The licensee documented the corrective actions for the refueling water storage tank level transmitter issue in Performance Improvement Request 97-3958. The licensee determined that Updated Safety Analysis Report, Section 7.4.1 was incorrect in stating that the level instruments were required to maintain a hot standby under a non accident condition. The licensee corrected the Updated Safety Analysis Report section using Updated Safety Analysis Report Change Request 97-203.

This item remains open pending further NRC review of the licensee's Updated Safety Analysis Report upgrade program.

E8.29 (Closed) Inspection Follow up Item 50-482/9604-03: Safety-Related Battery Replacement with AT&T Round Cells

a. Background

This item involved concerns that previous industry problems with the AT&T round cell batteries were not sufficiently understood to provide assurance that they would not occur at Wolf Creek.

b. Inspection Followup

The team was familiar with problems encountered with AT&T round cell batteries at other nuclear facilities involving the AT&T high specific gravity cells. The cells installed at Wolf Creek, however, were of a different design, termed "low specific gravity cells."

AT&T had been manufacturing low specific gravity cells for over 20 years and supplying them to commercial and telecommunication facilities. The cells penormed well and battery capacity was noted to increase with age. When some nuclear facilities requested higher capacity batteries, AT&T raised the specific gravity of the cells in order to increase capacity. This was an extrapolation of their standard low specific gravity technology, and one in which they had limited experience, which resulted in the noted industry problems.

Since installation of the batteries at Wolf Creek in March 1996, they have performed adequately. The discharge test performed during Refueling Outage 9 demonstrated that the batteries maintained the ability to provide the required capacity.

E8.30 Reactor Engineering Problem Identification Reports

a. Inspection Scope (37550)

The team reviewed three performance improvement requests relating to reactor engineering issues identified during the licensee's Updated Safety Analysis Report Fidelity Review. The team's review of the performance improvement requests assessed their safety significance and the licensee's corrective action plan and schedule for resolution.

b. Observations and Findings

Performance Improvement Request 98-0169

This performance improvement request involved an apparent discrepancy between the safety limits, as defined in the technical specifications, and the design temperature of the reactor coolant system, as defined in the Updated Safety Analysis Report. The performance improvement request was initiated on January 22, 1998, and was categorized as a nonsignificant, Level III performance improvement request.

Table 5.3-2 of the Updated Safety Analysis Report identified that the design temperature of the reactor coolant system (with the exception of the pressurizer) was 650 degrees F. The licensee's review identified that some plant operations allowed in accordance of Safety Limit Technical Specification, Figure 2.1-1, resulted in a T-hot temperature in excess of 650 degrees F. For example, for plant operation at 2250 psia, 100 percent reactor power, and 623 degrees F reactor average temperature, which is allowed by the safety limits, the T-hot temperature exceeded the reactor coolant system design temperature by approximately 5 degrees F.

The licensee recognized that this issue may be generic to Westinghouse nuclear steam supply systems and initiated discussions with Westinghouse for additional evaluation. The initiator of the performance improvement request recommended that: (1) the safety limit should not allow operation that permits T-hot conditions to exceed the reactor coolant system design temperature; (2) previous plant operation should be reviewed to determine if the plant has been operated within the allowed safety limit while exceeding the design temperature; (3) the Safety Limit basis should be revised to add consideration of reactor coolant system design temperature; and (4) reactor protection system set points should also be reviewed for impact.

The licensee performed a preliminary review of the performance improvement request and concluded that excessive T-hot temperatures should be prevented by the reactor protection system. Other additional actions proposed included performing a review of the accident analyses to compare temperatures during the transient to the reactor coolant system design temperature and determining additional actions based on the recommendations of the performance improvement request initiator. A due date of July 31, 1998, for completion of these actions was established.

The team considered this a valid issue requiring further evaluation. The licensee's time table for resolution appeared acceptable, given that abnormal plant operation would be prevented by the reactor protection system. The licensee's evaluation of this issue will be reviewed during a subsequent NRC inspection. This was identified as an inspection followup item (50-482/9812-07).

Performance Improvement Request 98-0179

This performance improvement request involved the identification of a discrepancy associated with the assumptions for the fuel handling accident evaluation in the Updated Safety Analysis Report. The performance improvement request was initiated on January 22, 1998, and was categorized as a nonsignificant, Level III performance improvement request.

The fuel handling accident evaluation in the Updated Safety Analysis Report identified that the analysis complied with Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the

Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors." Regulatory Guide 1.25 contained a note that stated that the assumptions were valid only if certain fuel limitations were not exceeded. The fuel limitations were: 1) Peak linear power density of 20.5 kW/ft for the highest power assembly discharged; 2) Maximum center-line operating fuel temperature less that 4500 degrees F for this assembly; and 3) Average burnup for the peak assembly of 25000 MWD/ton or less (this corresponds to a peak local burnup of about 45000 MWD/ton).

The initiator of the performance improvement request identified that fuel currently in use exceeded the limitations identified in 2) and 3) above. Section 4.2.1.2.a of the Updated Safety Analysis Report identified that a calculated fuel centerline temperature of 4700 degrees F had been selected as an overpower limit to ensure no fuel melting. Therefore, there was a 200 degrees F discrepancy in maximum allowed fuel centerline temperature. Also, the current operating cycle contained a limitation of 33500 MWD/ton core average burnup and 60000 MWD/ton peak local burnup, both of which exceeded the fuel handling accident assumption. The impact of these discrepancies were that the dose consequences contained in the fuel handling accident evaluation were nonconservative.

The licensee completed a preliminary evaluation of the performance improvement request. With respect to the fuel centerline temperature criterion, the licensee concluded that the peak centerline fuel temperature would not exceed 2000 degrees F during normal power operation. After the team identified that this conclusion was incorrect, the licensee reperformed their evaluation and identified that 2000 degrees F was the fuel average temperature and that the maximum fuel centerline temperature was less than 3600 degrees F. This was consistent with the Updated Safety Analysis Report. With respect to the fuel burnup, the licensee identified that NUREG/CR-5009, "Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors," stated that increasing fuel enrichment to 5.0 weight percent U-235 with a maximum burnup of 60000 MWD/ton increases the doses for a fuel handling accident by a factor of 1.2. However, the licensee also identified that increasing the results by 20 percent would still keep dose rates remain below the regulatory limits.

The licensee identified additional actions to be taken. These included performing a formal review of NUREG/CR-5009, revising the fuel fission product activity based upon this review, performing new analyses for the fuel handling accident and other accidents with the revised source term, and revising the Updated Safety Analysis Report. The licensee identified a completion date of December 31, 1998, for these actions.

The team considered that fuel may have been handled during the last several outages that may have contained a radiological source term that exceeded the assumptions and potential consequences of a fuel handling accident. This consideration will be reviewed further by the NRC and was identified as an inspection followup item (50-482/9812-08).

Performance Improvement Request 98-0179 also referred to related Performance Improvement Request 97-2783. This performance improvement request was initiated on September 11, 1997, and was categorized as nonsignificant, Level III. The team reviewed this performance improvement request, which identified that the dose consequences analysis of record may not be bounding for the duration of the current operating cycle. The performance improvement request identified that the Updated Safety Analysis Report dose calculations referenced WCAP 13447, "3579 MWt NSSS Rerating Engineering Report," which had been completed to support the licensee's rerating project. The analysis in WCAP 13447 supported a core average cumulative burnup of approximately 33500 MWD/ton; however, the projected burnup for the end of the current operating cycle was expected to be approximately 34430 MWD/ton. The burnup was expected to exceed the WCAP 13447 limitation at approximately 472 effective full power days. The team questioned the licensee regarding when it identified this discrepancy, at what time was the core expected to exceed the burnup limitation, what controls were in place to prevent exceeding the burnup limitation, and what corrective actions were being taken to resolve the issue.

The licensee informed the team that with nominal plant operation, the core was expected to achieve 472 effective full power days of operation in March 1999. No formal administrative controls were determined to be necessary by the licensee to restrict operation beyond this time because the reactor engineering staff were aware of the issue and were in close communication on a daily basis with the control room operators. The licensee informed the team that a plan was in place to complete the revised analyses well before that time. The team identified the review of the licensee's implementation and completion of these analyses as an inspection followup item (50-482/9812-09).

Performance Improvement Request 98-0412

This performance improvement request involved the identification of a discrepancy between the as-measured limit for the enthalpy-rise hot channel factor, F-Delta-h, identified in the core operating limits report, and the limit for F-Delta-h identified in the technical specifications safety limits. The performance improvement request was initiated on February 16, 1998, and was categorized as a nonsignificant, Level III performance improvement request.

The safety limit for F-Delta-h was 1.65 and included an allowance of 4 percent for measurement uncertainty. The core operating limits report for the current operating cycle specified a limit of 1.59. Accounting for 4 percent measurement uncertainty, the maximum allowed measured value of F-Delta-h was approximately 1.5865, which was nonconservative compared to the core operating limits report. The initiator of the performance improvement request recommended that a review be performed to verify that the as-measured values of F-Delta-h did not result in exceeding the safety limit when the 4 percent measurement uncertainty factor was properly included. Also, the initiator recommended that an evaluation be performed to determined if the core operating limits report limit for F-Delta-h should be reduced to 1.58.

The licensee's initial evaluation confirmed that application of the 4 percent measurement uncertainty factor to the safety limit resulted in a 1.5865 limit for unadjusted F-Delta-h. The evaluation also identified that this value was rounded to 1.59 in the core operating limits report. The licensee provided justification for this by identifying that the additional digits were nonsignificant figures for a measurement uncertainty of 4 percent. Also, the propagation of other additional uncertainties applied to the F-Delta-h value for departure from nucleate boiling analyses in the Updated Safety Analysis Report provided additional assurance that using the core operating limits report measured limit of 1.59 was acceptable. The licensee closed the performance improvement request on March 5, 1998. The team concurred with the conclusion of the licensee's assessment.

Safety Significance Classification

The team reviewed Procedure AP 28A-001, "Performance Improvement Request," Revision 9, to determine if it had correctly classified the above performance improvement requests. The team noted that Level I and II performance improvement requests were classified as "significant conditions adverse to quality," required a formal root cause evaluation, and corrective actions to prevent recurrence. Level III performance improvement requests were classified as "conditions adverse to quality," and did not require a detailed root cause evaluation or corrective action plan. The team noted that Procedure AP 28A-001 did not explicitly identify the area of engineering calculations or safety analyses for inclusion in the performance improvement request process, although the procedure did state that performance improvement requests were used to document the evaluation and resolution of problems, concerns, or recommendations. There were no instructions or examples in the procedure for how calculation errors should be assessed for significance or addressed for resolution. The team was concerned that this could result in the misclassification of issues. Although none of the performance improvement requests resulted in an immediate operability concern, the team considered the lack of including safety analyses and other engineering calculations in its performance improvement request procedure a weakness that could result in misclassification of issues.

c. Conclusion

The team did not identify any immediate operability concerns as a result of its review of the above performance improvement requests. However, a future operability concern existed with respect to the burnup limitations of the safety analyses for operation late in the current operating cycle and a potential reportability issue existed for handling fuel that may have exceeded dose consequence analysis assumptions. The team identified a weakness in the licensee's procedure for performance improvement requests in that the procedure did not address the significance or processing of problems with safety analyses or engineering calculations.

IV. Plant Support

F1 Fire Protection Program

a. Inspection Scope (64704)

The team inspected the licensee's fire protection program to verify that the licensee had properly implemented and maintained the fire protection program required by the operating license. The team reviewed fire protection procedures, administrative controls, quality assurance audit reports, fire brigade qualifications, fire brigade staffing, and fire watch staffing in accordance with the approved fire protection program. The team also conducted walkdowns and tours of the facility to verify licensee implementation of the approved fire protection program.

b. Observations and Findings

During the inspection, the team noted that most administrative controls were properly implemented and that most administrative control procedures were adequate. In addition the fire brigade and fire watch personnel were qualified, plant housekeeping for control of transient combustible materials was very good, the number of component impairments/breaches was very low, and station fire response equipment was generally well maintained. However, the team noted instances where the fire protection program had not been adequately implemented. These included: 1) offsite fire brigade training and drills had not been conducted annually as required; 2) the fire water suppression system had historically been used for nonfire protection purposes without evaluation of the effect on fire suppression capability; 3) a preventive maintenance program did not exist for electrical relays in the diesel-driven fire pump start circuitry; and 4) the reactor coolant pump lube oil collection system requirements were not evaluated properly when a deviation was identified. These items are discussed in other sections of this report.

The team noted that some of the fire protection program implementation problems had occurred in the past, were self-identified or self-revealing, and any performance concerns were corrected. The fire protection and quality assurance organization staff had identified areas for improvement and the fire protection organization appeared committed to maintain an effective fire protection program.

c. Conclusions

The team considered the implementation of the fire protection program to be good, although some examples of problems were identified.

F2 Status of Fire Protection Facilities and Equipment

a. Inspection Scope (64704)

The team performed a walkdown of accessible areas of the facility containing safe shutdown equipment. The team also visually inspected fire protection equipment located throughout the facility, including fire suppression and detection equipment, fire barriers, and fire brigade and operator emergency response equipment located in equipment storage areas.

The team also randomly selected components required for post-control room fire safe shutdown by Procedure OFN RP-017, "Control Room Evacuation," Revision 11, which could be required for safe shutdown during a control room fire, to verify that they were accessible, well labeled, and had adequate emergency lighting to perform required tasks.

b. Observations and Findings

The team observed that most fire response equipment was well maintained, accessible, within calibration, and in good working order. All valves observed by the team in the fire suppression systems were in their proper position. Preventive maintenance of fire protection equipment was performed in accordance with approved procedures. However, during the week of March 30, 1998, the licensee performed the annual preventive maintenance of the diesel-driven fire pump in accordance with Procedure STN FP-410, "Diesel Engine Inspection." During post-maintenance testing per Procedure STN FP-211, "Diesel Fire Pump Operability and Fuel Level Check," on April 2, 1998, the engine failed to start on demand. The licensee identified that the cause of the failure was a failed relay in the engine start circuitry. After replacement of the failed relay, and other relays in the engine start circuitry, the pump was returned to an operable condition.

The licensee determined that its preventive maintenance program did not include inspection or replacement of relays in the engine start or alarm circuitry. Performance Improvement Request 98-0964 was initiated to document this event and it was categorized as a significant condition adverse to quality requiring a root cause evaluation. The licensee also determined that this event required evaluation as a maintenance preventable functional failure per the maintenance rule. The team considered the licensee's failure to include inspection and periodic replacement of the relays for the diesel-driven fire pump a weakness in the preventive maintenance program. The licensee informed the team that periodic inspection and replacement of relays would be added to the program as part of the corrective actions for the performance improvement request. The review of the licensee's corrective actions in response to this failure was identified as an inspection followup item (50-482/9812-10).

The team noted that all fire brigade response equipment in the fire brigade storage areas was well maintained and ready for immediate use with the exception of two carbon dioxide fire extinguishers. The team identified that these two fire extinguishers did not have current monthly inspection tags and that one of them was empty. The fire extinguishers were identified by a sign that stated, "For Emergency Use Only," but the team learned that they were extra equipment available for brigade use in addition to the minimum equipment required by the fire protection program. The last monthly fire extinguisher inspection, completed on March 7, 1998, per Work Package 126378, did not include a requirement to inspect the subject extinguishers. The licensee initiated Performance Improvement Request 98-0871 to correct the deficiency.

The team reviewed the list of active fire protection equipment impairments and breaches for which compensatory measures had been implemented, and accompanied a fire watch performing a tour of the affected areas. There were only four fire protection impairment control and breach authorization permits that required a compensatory fire watch. The team considered this low number of impairments to be a strength. However, the team noted that one of the inoperative components, the control room pantry automatic door closer, had been inoperable since March 1996. The original design of the system was for the door to automatically close and isolate the control room from the pantry in the event of a fire in the pantry. However, when a new fire detection system was installed in 1996, the new system was unable to control the door closer. Therefore, Temporary Modification Order 96-017-KC was implemented on March 18, 1996, to defeat the autoclosure capability of the door until a permanent modification was designed and installed. Additionally, on March 17, 1997, the pantry ionization detector was made inoperable due to frequent nuisance alarms during routine cooking activities. Hourly fire watch patrols of the pantry (which was next to the continuously manned control room) were properly implemented as compensatory action for both of these impairments.

The licensee informed the team that a permanent modification was planned to replace the ionization detector with a thermal detector and restore the automatic door closure capability. The modification was scheduled for implementation per Plant Modification Request 04519 during the week of May 4, 1998. The control room pantry was used by operators for meal preparation and cooking activities and the team considered that these activities represented a potential fire hazard. The team considered that although the area was provided with a compensatory hourly fire watch patrol and that the adjacent control room was continuously manned, the length of time Temporary Modification Order 96-017-KC was excessive.

c. Conclusions

Fire protection equipment required for program implementation was generally well maintained and available for immediate use. The team concluded that the self-revealing failure of the diesel driven fire pump to start during a post-maintenance test indicated that a weakness existed in the preventive maintenance program for the start circuitry. The low number of impairments was identified as a strength.

F3 Fire Protection Procedures and Documentation

a. Inspection Scope (64704)

The team reviewed the licensee's approved program as defined in the Updated Safety Analysis Report for the facility. The team reviewed the procedures listed in the attachment to this report to verify that the procedures adequately implemented the licensee's approved program.

b. Observations and Findings

The team found that, with the exception of the item noted below, the procedures adequately implemented the approved fire protection program.

Section 9.5.1.7.5.2.1.5 of the Updated Safety Analysis Report stated that over each 2-year period following initial qualification, fire brigade members receive periodic refresher training such that all training subjects are completed within the 2-year period and must complete all of the refresher training to maintain active status. The team identified that Procedure AP 10-105, "Fire Protection Training Program," Revision 1, Change 98-060, allowed a 31-day grace period for brigade members to complete qualification requirements prior to being removed from active status. During a review of training attendance records of 13 randomly selected brigade members and leaders, the team identified that 5 individuals had exceeded the 2- year requalification cycle for training, but completed their training requirements within the procedurally-allowed grace period.

The team informed the licensee that its fire protection program did not allow the grace period contained in Procedure AP 10-105 and that brigade members had inappropriately used the grace period to complete their requalification training requirements. The team did not have a safety concern regarding fire brigade member knowledge or performance because of the short period of time in excess of 2 years that elapsed before the brigade members received their training. The team considered the failure to complete fire brigade requalification training within 2 years to be a violation of the fire protection program.

Operating License NPF-42, Section 2.C.(5)(a) requires that the licensee shall maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report and as approved in the NRC Safety Evaluation Report. Section 2.C.(5)(b) allows the licensee to make changes to the approved fire protection program without prior approval of the NRC only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. This failure to maintain the fire protection program as documented in the Updated Safety Analysis Report constitutes a violation of minor significance and is not subject to formal enforcement action. The licensee initiated Performance Improvement Request 98-0995 to correct this discrepancy and informed the team that it intended to perform the proper evaluation to support changing its fire protection program to allow implementation of the grace period. This minor violation is addressed in this report to document that grace periods are not applicable in fire protection training and scheduling and that the licensee's corrective actions were complete.

c. Conclusions

With exception of the minor violation addressed above, the team determined that the fire protection program procedures adequately implemented the approved fire protection program.

F4 Fire Protection Staff Knowledge and Performance

a. Inspection Scope (64704)

The team reviewed the adequacy of the fire protection staff by conducting interviews and plant walkdowns with staff members. The team also accompanied fire watch personnel on fire watch patrol.

b. Observations and Findings

Discussions with the fire protection staff indicated that they understood NRC requirements for the fire protection program and the National Fire Protection Association, National Fire Code requirements. They also demonstrated a detailed understanding of fire hazards associated with the facility and a detailed knowledge and understanding of the systems, testing, and analyses associated with the fire protection program.

During an accompaniment with a fire watch on patrol of the facility, the fire watch demonstrated thorough knowledge of his duties and a conscientious attitude to the identification of potential problems. The team observed that the fire protection personnel had a very good working relationship with other onsite organizations.

c. Conclusions

The plant had a qualified fire protection staff which had a very good working relationship with other station organizations. The fire watch program was effectively implemented.

F5 Fire Protection Staff Training and Qualification

a. Inspection Scope (64704)

The team reviewed the readiness of onsite fire brigade personnel to fight fires and ability of fire watch personnel to perform compensatory measures for fire protection component impairments and fire barrier breaches. The team reviewed the fire brigade composition, qualifications (including medical), and training records to determine if the fire brigade met the requirements of the fire protection plan. The team also reviewed a quality assurance audit finding regarding the offsite fire brigade.

b. Observations and Findings

The 1997 quality assurance audit of the fire protection program identified that offsite fire brigade training and drills had not been performed in accordance with the fire protection plan. Specifically, offsite fire brigade training had not been conducted since 1993 and the offsite fire brigade had not participated in a fire drill since 1994. The licensee initiated Performance Improvement Requests 97-3726 and 97-3972 to address these items, respectively.

Section 9.5.1.7.5.2 of the Updated Safety Analysis Report identified that training for the offsite fire department is required annually and that the offsite fire department is required to participate in a fire drill annually. The team also reviewed the February 5, 1996, "Agreement for Fire Protection," between the licensee and offsite fire department. The Agreement identified that drills and training were to be conducted on at least an annual basis.

Operating License NPF-42, Section 2.C.(5)(a) requires that the licensee shall maintain in effect all provisions of the approved fire protection program as described in the Final

Safety Analysis Report and as approved in the NRC Safety Evaluation Report. Section 2.C.(5)(b) allows the licensee to make changes to the approved fire protection program without prior approval of the NRC only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. The failure of the licensee to conduct offsite fire brigade training and drills with offsite fire brigade participation on an annual basis is a violation of the fire protection program. The licensee implemented corrective actions including conducting training for the offsite fire department on March 11 and 25, 1998, and scheduling a fire drill with offsite fire department participation for May 16, 1998. Since the facility was designed to be self-sufficient with respect to onsite fire fighting capabilities, no credit is taken in the fire protection system design for offsite fire department response. Therefore, the team considered that this constituted a violation of minor safety significance and is not subject to formal enforcement action. This minor violation is addressed in this report to document that if changes are made to the fire protection program, changes to associated documents must also be made.

c. Conclusions

The team considered the licensee's onsite fire protection staff training to be adequate to meet fire protection program requirements with one minor exception. A noncited violation was identified for the licensee's failure to conduct annual training and drills for the offsite fire brigade.

F6 Fire Protection Organization and Administration

a. Inspection Scope (64704)

The team reviewed the fire protection program organization designated to implement the fire protection program.

b. Observations and Findings

The fire protection organization was described in Procedure AP 10-100, "Fire Protection," Revision 1. This procedure constituted the Fire Protection Manual, as described in the Updated Safety Analysis Report, and detailed staffing and responsibilities for the implementation of the program. The team noted that implementation was consistent with the approved program

c. Conclusions

The team found that the fire protection organization and administration was implemented in accordance with the fire protection program.

F7 Quality Assurance in Fire Protection Activities

a. Inspection Scope (64704)

The team reviewed the 1996 and 1997 quality assurance audits to verify that the audits met the requirements of the approved fire protection program.

b. Observations and Findings

The 1996 audit was the triennial audit, required by Technical Specification 6.5.2.8.f. The audit included a particularly detailed review of the licensee's fire barrier penetration seal program and Darmatt fire barrier installation project (for replacement of Thermo-Lag fire barrier material).

The 1997 audit was the biennial audit, required by Technical Specification 6.5.2.8.e. The audit included a particularly detailed review of plant modification packages.

The audits were comprehensive in scope and performed an in-depth evaluation of the fire protection program at the facility. Some of the problems identified by the audits included engineering review of plant change packages for impact on the fire protection program, offsite fire brigade training, and programmatic controls on Darmatt fire barrier installation. Issues identified in the audits were formally presented to the line organization and the line organization developed an audit response plan to evaluate the issue, identify corrective actions, and track the item to closeout.

c. Conclusions

The team found the fire protection program audits to be in compliance with the requirements of the program. The audits were effective and resulted in meaningful findings.

F8 Miscellaneous Fire Protection Issues (92903, 93809)

F8.1 (Closed) Violation 50-482/9519-01: Failure to Provide Adequate Emergency Lighting for a Valve Needed for Safe Shutdown Manual Manipulation

(Closed) Licensee Event Report 50-482/95-005: Failure to Develop an Adequate Fire Protection Program for Emergency Lighting

a. Background

The NRC inspectors identified that a valve required for manual operation to achieve safe shutdown following a control room fire did not have adequate emergency lighting available. During its followup of this violation, the licensee conducted plant walkdowns by engineering and operations personnel with normal and standby lighting turned off, and identified additional examples of locations where emergency lighting was inadequate. The licensee reported this event to the NRC in Licensee Event Report 50-482/95-005.

b. Inspection Followup

The team reviewed the licensee's corrective actions as identified in the response to the violation and the licensee event report. The licensee evaluated the deficiencies identified in its plant walkdowns and added or adjusted emergency lights to ensure that adequate emergency lighting was provided for operation of safe shutdown equipment and for access and egress routes to that equipment. The team verified that the licensee had implemented interim compensatory actions which included initiating an order that all operators carry flashlights, increasing the priority for maintenance on emergency lights, and installing temporary backup lighting if necessary. The licensee revised its procedure MPE BA-010, "Preventive Maintenance on Teledyne Emergency Lighting," to include the additional lights and revised aiming instructions. The team concluded that the licensee's actions in response to this violation and licensee event report were acceptable.

F8.2 (Closed) Licensee Event Report 50-482/97-016, Revisions 0, 1, and 2: Use of Fire Protection Pumps for Non-Fire Protection Purposes Constituted a Significant Degradation of Fire Protection System

a. Background

During a review of uses of the fire protection system, the fire protection engineer identified that the system had repeatedly been used over the life of the plant for nonfire protection purposes including cleaning and maintenance activities. The licensee determined that there was insufficient evaluation of the impact of these activities on fire protection system operability. Further, the licensee identified that the fire protection system could have been significantly impaired and unable to provide required pressure and flow at the location of a fire.

The licensee initiated Performance Improvement Request 97-2687 and conducted a root cause and significance evaluation of this condition. The licensee determined that the fire protection water supply system piping and pumps were sized and installed to supply 3300 gpm at 80 psig at the furthest interface point. This design basis was chosen to accommodate the greatest suppression system flow demand (2300 gpm, which was located in a nonsafety-related area) and a 1000 gpm hose stream backup capability. The Fire Hazards Analysis identified that the largest suppression system demand for a fire in a safety-related area was 1035 gpm. The licensee performed a historical review of fire water usage for nonfire protection purposes, conducted a test of the fire protection system on September 19, 1997, and determined that the maximum nonfire protection demand on the system was approximately 2140 gpm. Therefore, enough margin was available to provide water to the maximum fire suppression system demand in a safety-related area and still maintain the ability to achieve and maintain safe shutdown. However, manual hose stream backup capability would not have been available. For nonsafety-related areas, the maximum nonfire protection demand on the fire protection system would have exceeded the capability of the fire protection system to meet the largest fire suppression demand.

The licensee concluded that root causes for this event included: 1) that fire protection program management was not adequate to ensure that all uses of the fire protection pumps were thoroughly evaluated, and 2) personnel were not adequately trained with respect to system operability requirements such that nonfire protection uses of the system had become the accepted norm.

The licensee implemented immediate corrective actions by issuing Special Order SO-07, "Use of Fire Protection System for Non-Fire Protection Purposes," on October 1, 1997, which prohibited nonfire protection use of the fire protection system without engineering evaluation and approval of the plant manager. Other corrective actions included reviewing and evaluating operations procedures to identify those that used fire protection system water in supporting other activities, and developing a procedure to govern use of the fire protection system pumps.

b. Inspection Followup

The team reviewed the event reports and performance improvement request documentation. The team also reviewed Calculation KC-413, "Determine the Flow Requirements of the Fire Pump," Revision 0, and the Fire Hazards Analysis that supported the licensee's determination that sufficient water supply would have been available for the largest water suppression system demand in a safety-related area. However, the team noted that Calculation KC-413 also identified that the fire protection system water supply was designed to provide an additional 1000 gpm for yard hydrants (or hose streams). This additional margin would not have been available during many of the instances the system was used for nonfire protection purposes.

The licensee was required to comply with its approved fire protection program. The fire protection program required that the fire protection system be capable of supplying a maximum system demand of 2300 gpm at 80 psig, plus simultaneous flow of 1000 gpm for outside hose streams. On many occasions over at least a 10-year period, the licensee used the fire protection system for nonfire protection purposes. The licensee determined that the largest demands on the fire protection system for nonfire protection purposes occurred during the fall of 1996 through the spring of 1997, and were as high as 2140 gpm.

Operating License NPF-42, Section 2.C.(5)(a) requires that the licensee shall maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report and as approved in the NRC Safety Evaluation Report. The team concluded that since the fire protection system was not maintained in accordance with the fire protection program, the fire protection system was inoperable when it was used for these nonfire protection purposes and that this was a violation (50-482/9812-11). However, this licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. The team reviewed Special Order SO-07, Procedure SYS FP-293, "Fire Pumps Manual Operations," Revision 7, which had been revised to govern the administrative control of all fire pump manual operations, and interviewed fire protection and operations staff. The team concluded that the licensee's evaluation of this event was thorough and that it had established acceptable measures to prevent recurrence.

F8.3 (Closed) Inspection Followup Item 50-482/96023-04: Reactor Coolant Pump Motor Lube Oil Collection System

a. Background

During the NRC inspection, the inspectors reviewed the licensee's followup of industry information relating to reactor coolant pump lube oil fires. The licensee documented in Performance Improvement Request 96-3133, on December 2, 1996, that it had not tracked a recommendation from an earlier industry operating experience evaluation to conduct further reactor coolant pump lube oil leakage inspections and install additional oil drip pans if leakage continued to occur. The inspectors initiated this item to track the resolution of this issue.

b. Inspection Followup

The team reviewed the licensing basis for reactor coolant pump lube oil collection at the facility, the licensee's operating experience evaluations, and resolution to oil leakage via engineering evaluation and plant modification.

Operating License NPF-42, Section 2.C.(5)(a) requires that the licensee shall maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report and as approved in the NRC Safety Evaluation Report. Section 2.C.(5)(b) allows the licensee to make changes to the approved fire protection program without prior approval of the NRC only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. Generic Letter 86-10, "Implementation of Fire Protection Requirements," provided guidance to the industry regarding the analysis required by the licensee to support changes to the approved fire protection program including the applicability to the provisions of 10 CFR 50.59.

The licensee initiated Industry Information Program Report 02805, "NRC Information Notice 94-58: Reactor Coolant Pump Lube Oil Fire (Haddam Neck, Millstone), on September 15, 1994. The approved fire protection program at that time, contained in the Updated Safety Analysis Report, identified that the licensee was committed to the requirements of 10 CFR Part 50, Appendix R, Section III.O, and NRC Branch Technical Position CMEB 9.5-1 for reactor coolant pump lube oil collection systems. The requirement, in part, was that the "...collection system shall be capable of collecting lube oil from all potential pressurized and unpressurized leakage sites in the reactor coolant pump lube oil systems... Leakage points to be protected shall include lift pump and piping, overflow lines, lube oil cooler, oil fill and drain lines and plugs, flanged connections on oil lines, and lube oil reservoirs where such features exist on the reactor coolant pumps. . . ." The licensee documented in Industry Information Program Report 02805 that it had identified minor oil leakage from RTD terminal box conduit compression fittings on the reactor coolant pumps during Refueling Outage 7 (1994). The engineering evaluation summarized the leaks as minor and that ignition of a fire could not be expected. Maintenance was performed to tighten the leaking fittings. The report identified a recommendation that if oil leaks from the fittings or similar leaks continued, then local leak collection devices should be installed. The report did not, however, document an evaluation regarding the licensee's compliance with the regulatory requirements for oil collection, nor did it evaluate the potential impact of oil leakage from these leakage points during the next operating cycle.

The licensee initiated Performance Improvement Request 96-3133 on December 2, 1996, to perform an evaluation of the Arkansas Nuclear One reactor coolant pump fire. This item identified that the 1994 recommendations for monitoring and installing oil collection devices were not completed or tracked. The licensee completed Reportability Evaluation Report 97-022 on March 27, 1997, to evaluate the oil leakage history of the reactor coolant pump motors. The report documented that lube oil leakage from the "A" reactor coolant pump motor was identified by control room operators on August 7, 1995, during the operating cycle following Refueling Outage 7. The leakage was evaluated as acceptable by the engineering staff and operation continued. The licensee did not document a fire protection evaluation of the leak at that time. With the unit shutdown on January 30, 1996, an inspection was performed and the licensee identified that the RTD fitting on the "A" motor had leaked. Approximately 5 gallons was added to the oil reservoir to refill it. The licensee's evaluation of the impact of the leak concluded that based upon its magnitude and path of travel, its location relative to insulation and hot pipe, and the ignition characteristics of the oil, the leakage was not a combustibility hazard. The licensee concluded that at no time would the oil leakage have resulted in a loss of function for any safety-related equipment, a potential for degradation of safety-related equipment, nor was it a condition outside the design basis of the plant. Therefore, the event was considered to be not reportable to the NRC per 10 CFR 50.72 or 10 CFR 50.73.

Reportability Evaluation 97-022 also documented that the licensee was not in compliance with regulatory requirements and that the adequacy of the lube oil collection system and any necessary design changes would be evaluated and implemented during the closeout of Performance Improvement Request 96-3133. The licensee intended to implement design changes to eliminate any potential uncontained lube oil leakage paths.

During the licensee's evaluation of options during resolution of Performance Improvement Request 96-3133, the licensee decided to install a modification to the reactor coolant pump motor upper reservoir RTD conduit boxes to prevent oil leakage. Modification DCP 07280, "RTD Conduit Seals," was prepared and consisted of a plan to install a new sealed conduit design with leak tight fittings on the RTD conduit boxes to prevent or minimize lube oil leakage. The licensee's unreviewed safety question determination concluded that oil leakage would be eliminated or negligible, bounded by the evaluation for a 5 gallon oil leak, and would not represent a fire hazard. Therefore, no collection drip pan was included as part of the design for this potential leakage path.

As allowed by License Section 2.C.(5)(b), the licensee changed the fire program documentation contained in the Updated Safety Analysis Report based on its conclusion that the deviation between the existing NRC-approved program and the as-built, as-operated configuration of the lube oil collection system did not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire, nor constitute an unreviewed safety question. The revised fire protection program identified that, "The RTD conduit boxes were not provided with drip pans, however, conduit seals and leak tight fittings are used to minimize lube oil leakage. Oil leakage at the RTD conduit box does not represent a fire hazard."

The licensee installed DCP 07280 during Refueling Outage 9 (fall 1997) and revised Procedure MPE M712Q-02, "Reactor Coolant Pump Motor Inspection," Revision 8, to include an inspection of the RTD conduit boxes for oil. The team also verified that lube oil reservoir level monitoring and alarm capability existed in the control room and that during the current operating cycle there had not been any unusual reduction in lube oil inventory that may indicate a leak.

Operating License NPF-42, Section 2.F, requires, in part, that the licensee shall report any violations of the requirements contained in Section 2.C of this license within 24 hours to the NRC via the Emergency Notification System (ENS) with written followup within thirty days in accordance with the procedures described in 10 CFR 50.73(b), (c), and (e). Operating License NPF-42, Section 2.C.(5)(a), requires that the licensee maintain in effect all provisions of the approved fire protection program as described in the Updated Safety Analysis Report for the facility. The Wolf Creek Updated Safety Analysis Report, Table 9.5E-1, states, in part, that the reactor coolant pump shall be equipped with an oil collection system and that such collection systems shall be capable of collecting lube oil from all potential pressurized and unpressurized leakage sites in the reactor coolant pump lube oil systems. On September 15, 1994, December 2, 1996, and March 27, 1997, the licensee identified that reactor coolant pump lube oil was leaking from sites that were not provided with a lube oil collection system. This was a violation of Operating License Section 2.C.(5)(a). However, this licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-482/9812-11). After discussions with the team, the licensee reported this violation to the NRC in accordance with Operating License, Section 2.F. An ENS notification was made on April 9, 1998, and LER 50-482/98002 was issued on May 11, 1998. The team reviewed the LER and the licensee's corrective actions taken and planned to correct the violation and prevent recurrence, and found them to be adequate.

V. <u>Management Meetings</u>

X1 Exit Meeting Summary

The team met with licensee representatives on April 10, 1998, and on June 26, 1998, to conduct a technical debrief prior to leaving site. Following additional in-office review and telephonic discussions of the team's findings, an exit interview was conducted by telephone on May 19, 1998. Following additional review of documents and conference telephone calls, a supplemental exit meeting was conducted by telephone on July 20, 1998. The licensee acknowledged the team's findings.

The team leader noted that team personnel had reviewed proprietary documentation during the course of the inspection. Proprietary documentation was not divulged in this report. The licensee acknowledged the team's findings.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Alford, Licensing Engineer
D. Claridge, Senior Licensing Engineer
T. Garrett, Manager, Design Engineer
T. Harris, Supervisor, Licensing
R. Holloway, Design Engineering
D. Jacobs, Manager, Support Engineering
D. Knox, Manager, Maintenance
B. McKinney, Plant Manager
R. Muench, Vice President, Engineering
C. Rich, Jr, Supervisor, Electrical and Instrumentation and Control
C. Reekie, Licensing
B. Selbe, Project Engineer
R. Sims, Manager, System Engineering
B. Smith, Supervisor, Design Mechanical
L. Solorio, Design Engineering
L. Stevens, Supervisor, Nuclear Safety Engineering
J. Yunk, Senior Engineer, Licensing

NRC

F. Ringwald, Senior Resident Inspector
B. Smalldridge, Resident Insp .ctor

INSPECTION PROCEDURES USED

37550	Engineering
92904	Followup- Plant Support
92903	Followup - Engineering
64704	Fire Protection Program
93809	Safety System Engineering Inspection (SSEI)

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-482/9812-01	VIO	Failure to Receive NRC Approval of a Change That Created an Unreviewed Safety Question as Required by 50.59

Opened

50-482/9812-02	VIO	Failure to Follow Design Control Procedures and to have Adequate Design Control Procedures
50-482/9812-03	IFI	Review Revised Battery Sizing Calculation NK-E-002
50-482/9812-04	IFI	Review Revised Electrical Cabinet Seismic Qualification Calculation
50-482/9812-05	VIO	Failure to Translate the Design Basis Into Specifications and to Verify and Check the Adequacy of Design Specifications
50-482/9812-06	NCV	Failure to Isolate the Spent Fuel Pool Heat Exchanger During Plant Cooldown
50-482/9812-07	IFI	Review the Resolution of the Discrepancy Between the Technical Specification Safety Limits and the Design Temperature of the RCS
50-482/9812-08	IFI	Review the Dose Consequences for a Fuel Handling Accident
50-482/9812-09	IFI	Review the Licensee's Analysis for Extended Core Operation
50-482/9812-10	IFI	Review the Corrective Actions to Assure that the Diesel Driven Fire Pump Relays are Placed in the PM Program
50-482/9812-11	NCV	Failure to Declare the Fire Protection System Inoperable When the Fire Pumps are Used for Non-fire Protection Activities and Failure to Assure that the RCP Oil Collection System was in Accordance with License Conditions

Closed

50-482/9621-06	VIO	Procedure STS BG-004 did not Specifically Require Operators to Tighten or Verify the Mechanical Position Stops for Valves BGV-198, BGV- 199, BGV-200, and BGV-201
50-482/9621-05	VIO	Operability Determination was not Thoroughly Documented in the Shift Supervisor's Log as Required by Administrative Procedures.
50-482/EA96-470-02014	VIO	Two Examples of Inadequate 10 CFR 50.59 Safety Evaluations.
50-482/EA96-470-01013	VIO	Five Examples Where the Licensee Failed to Identify and Correct Conflicts Between Technical Specification Clarifications and the Technical Specifications.

Closed

50-482/EA96-470-01033	VIO	Quality-Related Document Instruction was not Appropriate to the Circumstances when the Licensee Allowed the Reactor Coolant System to be Cooled Down with One Inoperable Source Range Channel.
50-482/EA96-470-01023	VIO	Reactor Coolant Pump Flywheel Inspection Integrity.
50-482/9808-01	URI	Licensee Failed to Prepare Performance Improvement Requests for Twelve Final Safety Analysis Report Significant Discrepancies
50-482/9604-03	IFI	Safety Related Battery Replacement with AT&T Round Cells
50-482/9519-01	VIO	Failure to Provide Adequate Emergency Lighting for a Valve Needed for Safe Shutdown Manual Manipulation
50-482/95-005	LER	Licensee Event Report Failure to Develop an Adequate Fire Protection Program for Emergency Lighting
50-482/97-016, Revs 0, 1, and 2	LER	Use of Fire Protection Pumps for Non-Fire Protection Purposes Constituted a Significant Degradation of Fire Protection System
50-482/96023-04	IFI	Reactor Coolant Pump Motor Lube Oil Collection System
50-482/97201-01	URI	Cooldown Analysis
50-482/97201-02	IFI	Emergency Core Cooling System Leakage
50-482/97201-03	URI	Residual Heat Removal Pump Operation in Minimum Recirculation Mode
50-482/97201-06	IFI	Procurement of EDG Relay
50-482/97201-13	URI	Acceptance Criteria for Battery Test
50-482/97201-14	URI	Acceptance Criteria for Battery Test
50-482/97201-15	URI	Refueling Water Storage Tank Level Instrumentation
50-482/97201-16	URI	Seismic Qualification
50-482/97201-17	URI	Nitrogen Bottle Installation
50-482/97201-18	URI	Motor Operated Valve Differential Pressure
50-482/97201-19	URI	Component Cooling Water Low Temperature
50-482/97201-20	URI	Corrective Action for Component Cooling Water Operating Procedure

50-482/9812-06	NCV	Failure to Isolate the Spent Fuel Pool Heat Exchanger During Plant Cooldown
50-482/9812-11	NCV	Failure to Declare the Fire Protection System Inoperable When the Fire Pumps are Used for Non-fire Protection Activities
50-482/9812-12	NCV	Failure to Assure that the RCP Lube Oil Collection System Was in Accordance with License Conditions

Discussed

50-482/97201-07	IFI	Sizing of Class 1E Batteries
50-482/97201-08	IFI	Sizing of Class 1E Batteries
50-482/97201-09	IFI	Sizing of Class 1E Batteries
50-482/97201-10	URI	DC Load Flow/Voltage Drop
50-482/97201-11	URI	DC Load Flow/Voltage Drop
50-482/97201-12.	URI	DC Load Control
50-482/97201-21	URI	Updated Safety Analysis Report Discrepancies

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
gpm	gallons per minute
HEPA	high efficiency particulate, air
LER	licensee event report
LPSI	low pressure safety injection
PCT	peak clad temperature
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gage

PARTIAL LIST OF DOCUMENTS REVIEWED

PROBLEM IDENTIFICATION REPORTS

PIR NUMBER	SUBJECT	DATE
940204	performance improvement request was initiated due to conditions that may have existed for the main steam safety valves being outside of the Technical Specification tolerance for set points	August 1, 1994
950726	Over 45 Wrs had been generated to address concerns with the battery monitor	March 31, 1995
950938	Safety related excess letdown valve failed IST stroke time test and remained inoperable for approximately 2.5 years	April 21, 1995
950972	Three valves were found to be mounted slightly out of plumb with perfect vertical in the field	April 27, 1995
951453	Replace gauges for discharge suction and oil pressure on chiller units due to high failure rate	June 2, 1995
951627	Corrective action plan in Performance Improvement Request 950241 failed to prevent an inoperability determination of CCP during a surveillance test	June 25, 1995
951810	Appendix R Emergency Lights	
951838	Pressurizer safety valve did not have two as-found set point tests within ASME Code tolerances	July 24, 1995
952270	Three pumps identified as still having temporary startup strainers installed	September 14, 1995
952321	performance improvement request initiated to determine why a nonsafety related component was installed on safety related equipment	September 20, 1995
952582	Control room experienced a loss of water from the CVCS system when flow was introduced through the demin vessel	October 26, 1995
952880	Hydromoter for a valve would not properly control the valve while in the closed position	December 1, 1995
960088	A vent valve was shown on drawing as normally open when the valve should be shown as normally closed	January 10, 1996
960190	Plant had a significantly higher amount of component failures of indicators, recorders, and gauges than the rest of the agency	January 23, 1996

PIR NUMBER	SUBJECT	DATE
960282	Emergency Lights	
960314	During a test reactor coolant system pressure dropped below 325 psig	February 5, 1996
960801	Metal bellows type flexible hoses on the ccps were replaced with neoprene hoses	December 18, 1996
960863	performance improvement request implemented to track corrective actions for the flexible lube oil system tubing during normal maintenance activities	March 15, 1996
961418	Capillary tube attached to the high pressure side of the oil pressure switch was broken and alloled a high pressure oil leak	May 17, 1996
961423	Broken lug was found of an inlet damper which prevente the damper closure	May 20, 1996
961530	During maintenance bonnet was removed from a valve and a small amount of water sprayed from the valve	June 5, 1996
961648	During testing the noise of the air whistling past the control room doors was noted to be louder than previously noted with the control building supply fan secured	June 25, 1996
961804	A conflict existed between drawings and procedures regarding the temperature limit of the charging pumps bearing oil	July 15, 1996
962085	Note on drawing incorrectly stated that two valves were locked closed refueling operations	August 23, 1996
962128	A cyclic noise every 25 seconds was heard on the control building supply fan	August 30, 1996
963051	Flow through the control room pressurization system filter absorber unit was outside Technical Specifications	November 26, 1996
963123	During the clam treatment on the essential service water system the control om AC cooler did not appear to be receiving the proper leve f treatment	November 29, 1996
963133	Reactor Coolant Pump Motor Lube Oil Collection	
963301	Control room essential drawings were not correct	December 17, 1996
970232	Compressor motor to SGK05A unit tripped off line	January 27, 1997
970253	Equipment SGK09 could not add enough humidity to the air in the control room	January 29, 1997

PIR NUMBER	SUBJECT	DATE
970351	Gages were being damaged by pulsation and vibration	February 4, 1997
970519	During the performance of a test, valve BGV-0148 could not be closed	February 20, 1997
970873	Temperatures in the class 1E switchgear and battery rooms were trending higher than normal	March 21, 1997
971391	Initiated to address ineffective corrective actions while performing work on a valve	May 12, 1997
971491	performance improvement request initiated to evaluate corrective actions Callaway completed by closing off their normal air exhaust registers	June 12, 1995
972289	CVCS Train A exceeded its maintenance rule unavilability performance criteria	July 29, 1997
972396	Control room HVAC units were declared inoperable in order to replace the lower seal on the main control room door	August 8, 1997
972529	Snubbers were removed from pipe support for one month to prevent damage to snubbers. Operability of system was questioned	August 19, 1997
972539	Failure to perform VT-3 test on pressurizer safety valve body for the inservice inspection program	August 19, 1997
972687	Non-Fire Protection Use of Fire Pumps	
972783	Accident Analysis Fuel Burnup Assumptions	
973292	performance improvement request initiated to track engineering test results that determined that the required control building pressurization was maintained	October 20, 1997
973533	Seal injection filter high differential pressure alarm was received in the control room	October 31, 1997
973726	Offsite Fire Brigade Training	
973767	System engineer discovered that the air supply valve and air pressure regulator indicator for the reactor coolant system letdown to regenerative heat exchanger were damaged	November 15, 1997
973972	Offsite Fire Brigade Drill Participation	
980145	Seal injection line to the chemical and volume control system boron thermal regeneration system chiller pump was leaking	January 19, 1998

PIR NUMBER	SUBJECT	DATE
980169	Safety Limit/Updated Safety Analysis Report Fidelity	
980179	Fuel Handling Accident Analysis Updated Safety Analysis Report Fidelity	
980412	Safety Limit/Updated Safety Analysis Report Fidelity	
980443	Found a 30 amp fuse installed instead of a 3 amp	January 23, 1998
980735	Fire Protection Audit Issues	
980743	performance improvement request initiated to perform a root cause evaluation and determine corrective actions for pressurizer safety valve failures	March 18, 1998
980758	performance improvement request initiated due to an evaluation or a non-conformance report was not issued for pressurizer safety valve as-found set point failures during 1996	
980871	Two Carbon Dioxide Fire Extinguishers Not Inspected	
980964	Failure of Diesel-Driven Fire Pump to Start	
980995	Fire Brigade Training Time Allowance	

REPORTABILITY EVALUATION REQUESTS

RER NUMBER	SUBJECT	REV. OR DATE
95-015	RER initiated to evaluate the reportability of a pressurizer safety valve failing it's surveillance test	May 30, 1995
97-022,	Reactor Coolant Pump Motor Oil Leakage	
98-010	RER initiated to evaluate the reportability of pressurizer safety valves failing surveillance tests	March 4, 1998
98-011	RER initiated to evaluate the reportability of pressurizer safety valves failing surveillance tests	March 4, 1998
98-013	RER initiated to evluate the reportability of pressurizer safety valves failing surveillance tests	March 19, 1998

PROCEDURES

PROCEDURE NO.	TITLE	REV.
AP 03A-001	Fuse Verification and Control	1
AP 05-001	Change Package Planning and Implementation",	2
AP 05-002	"Dispositions and Change Packages"	3
AP 05-008	Fire Protection Review	0
AP 10-100	Fire Protection	1 OTSC 97-015
AP 10-101	Control of Transient Ignition Sources	3
AP 10-102	Control of Transient Combustible Materials	3
AP 10-103	Fire Impairments	5 OTSC 98-124
AP 10-104	Breach Authorization	7 OTSC 98-049
AP 10-105	Fire Protection Training	1 OTSC 98-060
AP 10-106	Fire Preplans	1
AP 10-107	Fire Incident Investigation and Reporting	1
AP 10-108	Fire Prevention Inspections	1
AP 28A-001	Performance Improvement Request	9
OFN RP-016	Control Room Evacuation	11
STS BG 100A	Centrifugal Charging System "A" Train Inservice Pump Test	18, 19
STS PE-001	Filter/Adsorber Visual Inspection - Safety Related Units	4
STS PE-002	Charcoal Adsorbent Sampling for Nuclear Safety Related Units	6
STS PE-004	Auxiliary Building and Control Room Pressure Test	9
STS PE-005	HEPA Filter In-Place Leak Test, Safety Repated Systems	4
STS PE-C06	Charcoal Adsorber In-Place Leak Test, Safety Related Units	7
STS PE-009	Control Room Ventilation Systems Flow Rate and Combined Pressure Drop Test	5
STS PE-009-BAC	Control Room Ventilation Systems Flow Rate and Combined Pressure Drop Test	5
STS PE-042B	Chemical and Volume Control System VCT and Charging Pump Suction Header Pressure Test	1

PROCEDURE NO.	TITLE	REV.
STS PE-0421D	CVCS CCP "A" Discharge Header Pressure Test	2
STS PE-042E	CVCS CCP "B" Discharge Header Pressure Test	2
STS PE-042F	CVCS Pumps Discharge Pressure Test	3
STS PE-042K	Chemical and Volume Control System Misc. Pressure Test	4
STS PE-044	Auxiliary Building and Control Room Pressure Test	
STS PE-044A	High Pressure Safety Injection System Pressure Test	5
STS PE-044C	High Pressure Safety Injection System Pressure Test	2
STS PE-044D	High Pressure Injection System Pressure Test	2
STS CV-210B	ECCS SI and residual heat removal Inservice Check Valve Test	3
SYS NK-201	Transferring Between NK Battery Chargers	0
SYS BG-120	CVCS Startup	24
SYS FP-293	Fire Pumps Manual Operations	7

SPECIFICATIONS

SPECIFICATION NO.	TITLE	REV
E-050A(Q)	Class 1E Batteries for WCGS	5
E-051(Q)	Battery Chargers for SNUPPS	5
E-051A(Q),	Swing Battery Chargers for WCGS	2
E-051B(Q	Electrically Operated Manually Controlled Transfer Switches	0
E-1R8900	Raceway Notes, Symbols, and Details	1

DRAWINGS

DRAWING NUMBER	TITLE	REV
E-11NK01	Class 1E 125 V DC System Meter & Relay Diagram	5
E-11NK02	Class 1E 125 V DC System Meter & Relay Diagram	4
E-11010	DC Main Single Line Diagram	4
M-1G051	Equipment Locations Control & Diesel Gen. Bldg & Common Corridor Plan	8
M-1G050	Equipment Locations Control Bldg & Common Corridor Plan	2

DRAWING NUMBER	TITLE	REV
M-12KC01	Fire Protection Turbine Building	5
M-12KC02	Fire Protection System	6
M-12KC03	Fire Protection System	2
M-12KC04	Fire Protection Halon System	1
M-12KC05	Fire Protection System	00
M-12KC06	Fire Protection Halon System	00
M-12KC07	Fire Protection Halon System	00

<u>CALCULATIONS</u>

NUMBER	TITLE	REV.
1-BCB-W-1	Minimum Wall Violation; F025, FW321, FW691 and FW690	0
2-ECB	Pipe Class ECB	0
AN-95-021	Determination of the ECCS Flow Rates During the Recirculation Phases	0
AN-96-074	RWST water level to supply adequate NPSH for the ECCS Pumps (Setpoint L-04)	0
BG-FW-004	Piping Stress Analysis of CVCS - Normal and Alternate Charging System	1
BN-6	Pressure Drop Calc for Line 08-HCB-8" (RWST Disch Hdr to CVCS Pump "B" Suct HDR) from Line 07-HCB-24" to Line BG-265'	0
BN-7	Pressure Drop Calculation for Line 07-HCB-24" (RWST Disch Hdr Line) from Branch Line 09-HCB-8" to Branch Line	0
BN-20	RWST Level Set Points	1
E-3	Class 1E Battery System	0
E-3-W	Class 1E Battery System	W-0
ECCS-5	Calculate Head Loss to Assure Adequate NPSH to CCP "A" during Cold Leg Recirculation in Accordance with PFD-RD-285-4. The area of concern is from residual heat removal Sump "B" thru suction header to CCP's.	0
ECCS-7	CCP "A" NPSH During Hot Leg Recirculation	0

NUMBER	TITLE	REV.
ECCS-45	Verify Adequate Resistance Exists in RCP Seal Injection Line to Limit Runout of CVCS Centrifugal Charging Pumps during ECCS Injection	0
ECCS-46	CC Pumps NPSH from RWST	0
EM-17	Pressure Drop Calculation for 75-BCB-CVCS to Boron Injection Tank	0
EN-20	Minimum Post-LOCA Recirculation Times	0
EQAL-SAP, M-751-00003	Auditable Link Report for Wolf Creek Unit 1	4
EQWP AE-2	AE followup item, Performance Improvement Request 98-0037	1
GK-02-W	Control Room Ventilation System	1
GK-02-W	Safety Related Control Room [illegible] HVAC Capabilities During Accident Conditions (SGK04A/B and SGK05A/B)	2
GK-03-W	Control Room A/C System Temp vs. CFM Curve	1
GK-03-W	Temp vs CFM Curve	1
GK-04-W	Failure of One Train	0
GK-91	Control Room Pressurization System: Determine Control Room Inleakage Characteristics	A
GK-112	HVAC - Control Building - Winter Operations	A
GK-230	Control Room Habitability: CO2 Buildup	0
GK-386	Control Building Ventilation - Normal Operation	3
GK-474	Control Room Pressurization System Filtration Unit Heater	1
HE-5	Mode C Delta P; Determine the pressure Drop from the Recycle Evaporator Package to the Boric Acid Tanks (Mode C pts 16-17)	0
HE-7	Mode A Operation - Pts 1-29, Delta P from CVCS to the RHTs.	1
KC-413	Fire Protection - Fire Pump Flow Requirements	0
KC-452	Fire Protection System - Water Supply Adequacy	0
M-GK-386	Control Building HVAC - Normal Operation	3
MEQ-M-72[illegible]-1	Environmental Qualification	6
NK-E-001	Class 1E DC Voltage Drop	1
NK-E-002	Class 1E Battery Sizing	3
NK-E-[illegible]3	Class 1E 125 V DC Batteries Short Circuit Study	0

NUMBER	TITLE	REV.
P-139	Snubber Reduction for CVCS - Normal Charging (Reactor Building)	0
PB BG 30	Pipe Break Analysis	0
PB 1125	Room No. 1125 P/T Volumes & Vent Areas	0
SA-91-016	ECCS Design Basis Injection Flowrates Re-Analysis in Supporting of the WCGS Power Re-Rating Project	0
SA-92-056	CCP & SI Pumps Runout Flowrates During the Recirculation Phase	0
SBG-3	Centrifugal Charging Pumps	A

PLANT MODIFICATIONS

MODIFICATION NUMBER	TITLE
DCP 03702	Reactor Coolant Pump Oil Fill Lines
PMR 04519	Upgrade Fire Detection System
DCP 05248	NK System Swing Battery Charger Installation, Revisions 0 - 11
DCP 05846	NK Battery Replacement, RevisionS 0 through 11
DCP 07280	Reactor Coolant Pump RTD Conduit Seals
TEMP MOD/TMO 96-017-KC	Control Room Pantry Fire Protection Equipment

PREVENTIVE MAINTENANCE AND SURVEILLANCE ACTIVITIES

MPE BA-010, Revision 6	Preventive Maintenance on Teledyne Emergency Lighting
MPE M712Q-02, Revision 8	Reactor Coolant Pump Motor Inspection
STN FP-410	Diesel Engine Inspection
STN GP-009, Revision 25	Emergency Radio and Equipment Check and Inventory
STN FP-211	Diesel Fire Pump Operability and Fuel Level Check
TMP 95-ENG-190, Revision 0	Emergency Lighting Walkdown

MISCELLANEOUS DOCUMENTS

Number	Title	REV. OR DATE
	Agreement for Fire Protection Between Wolf Creek Nuclear Operating Corporation and Coffey County Fire District #1	Februay 5, 1996
	Wolf Creek Updated Safety Analysis Report	
	Wolf Creek Technical Specifications	
	Safety Evaluation Report Related, Amendment No. 104	February 10, 1997
AP 29-003	Component Cyclic or Transient Limits	February 20, 1998
Bechtel letter	Control Room Doses	October 30, 1987
CKL ZL-001	Auxiliary Building Reading Sheets	February 17, 1998
CKL ZL-004	Turbine Building Reading Sheets	February 20, 1998
DG WCN06-76	Design Guide for Overcurrent Protection Coordination	0, 1
EMG ES-12	Transfer to Cold Leg Recirculation	November 1, 1996
EQWP AE-2	Large Pump Motors (Outside Containment)	August 3, 1983
License Amendment No. 102	Adopted ASTM D3803-1989 as the laboratory testing standard for charcoal samples; downrated the heater capacity from 15 kw to 5 kw.	September 4, 1996
MEQ-M-721-1	Centrifugal Charging Pump Environmental Qualification	August 2, 1996
NRC IR 50-482/97-201	Wolf Creek Generating Station Design Inspection	February 23, 1998
NUREG-0830	Safety Evaluation Report, Callaway	October 1981
PMR 03158	Deactivation of RH Sensors and Transmitters	June 10, 1993
PMR 04380	Changes design documentation to allow components served by CCW to operate with the temperature as low as 35F	September 1, 1993
QA AUDIT REPORT K15-002, K-468	Fire Protection Program	December 6, 1996
QA AUDIT REPORT	Fire Protection Program	March 19, 1998
Report 02805	Industry Technical Information Program Report, "NRC Information Notice 94-58: Reactor Coolant Pump Lube Oil Fire	

Number	Title	REV. OR DATE
SLT 83-0045	SNUPPS Vortex Analysis: Containment Recirculation Sump Testing	April 27, 1983
Special Order	Use of Fire Protection System for Non-Fire Protection Purposes	12:00 a.m.
TIN FB 1231406	Training Lesson - Fire Extinguishers and Extinguishing Agents	January 2, 1900
TIN FO 1235500	Training Lesson - Training for Coffey County Fire District #1	January 1, 1900
WC 14624	Calibration Data Sheet for Controlotron 990, Serial U1207	October 12, 1992
WC 14625	Calibration Data Sheet for Controlotron 990, Serial U1206	October 20, 1992
WCRE-08	WCGS Approved Fuse List	January 5, 1900
WP 115686,	PEM01A has a leak on the suction flange.	
WP 126378	Fire Extinguisher Monthly Surveillance	
WP 126598	Appendix R Emergency Lights in the Turbine and Diesel Generator Buildings Annual	
WP 128669-1	Oil leak on "B" CCP (PBG05B)	March 31, 1998
WR 00800-92	Component Cooling Water System Low Temperature Evaluation - Post-LOCA	December 22, 1992