APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-482/92-02 Operating License No.: NPF-42

Docket: 50-482

Licensee: Wolf Creek Nuclear Operating Corporation (WCNOC)
P.O. Box 411
Burlington, Kansas 66839

Facility Name: Wolf Creek Generating Station (WCGS)

Inspection At: Coffey County, Burlington, Kansas

Inspection Conducted: January 26 through March 7, 1992

Inspectors: G. A. Pick, Senior Resident Inspector
L. L. Gundrum, Resident Inspector
W. D. Reckley, Project Manager, Project Directorate IV-2, Division of Reactor Projects III/IV/V, Office of Nuclear Reactor Regulation
B. L. Bartlett, Senior Resident Inspector, Callaway
D. R. Calhoun, Resident Inspector, Callaway

Approved: A T Howell 4-9-92
A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted January 26 through March 7, 1992 (Report 50-482/92-02)

Areas Inspected: Routine, unannounced inspection including plant status, followup of previously identified NRC items, licensee event report (LER) followup, inoffice review of written reports of nonroutine events at power reactor facilities, prompt onsite response to events at operating power reactors, operational safety verification, surveillance observations, monthly maintenance observations, engineered safety features system walkdown, and 10 CFR Part 50.59 evaluation.

Results:

In the area of NRC followup of NRC identified items, LERs, and violations, licensee actions were found to be generally acceptable and were sufficient to close the subject items. However, two weaknesses were identified. In one instance, the Plant Safety Review Committee approved the closure of the licensee's review an NRC Information Notice that pertained to inadequate fuse control, even though the licensee had identified weaknesses in this area and had not fully formulated its long-term corrective action (paragraph 3.1.5). In a second instance, the corrective action associated with a reportable event only focused on correcting the specific event even though there were previous similar occurrences (paragraph 3.3.6).

A reactor trip from 100 percent power occurred on February 19, 1992, following the loss of a 120 volt alternating current (AC) instrument bus. The operators responded well to the trip. However, licensee identified weaknesses in an off-normal procedure may have contributed to the trip (Section 4).

In the area of operational safety verification, several personnel errors occurred. Three of these issues resulted in a violation of NRC requirements and are similar to issues that were identified in NRC Inspection Report 50-482/91-36 (Sections 5.5, 5.8, and 5.11). Three other problems appeared to have been caused by inattention to detail (5.4, 5.6, and 5.15). The licensee's long term actions associated with the permanent cavity seal ring melted borated polyethylene will be tracked by an inspector followup item (Section 5.3). The results of the NRC's special inspection of the February 28, 1992, noise inside containment event will be documented in NRC Inspection Report 50-482/92-06 (Section 5.2).

The results of the performance of observed surveillance activities was again mixed. While all observed surveillances were satisfactorily performed, a number of weaknesses were identified. These included weak radiological control practices and one personnel safety concern. In addition, weaknesses in a reactor coolant system isolation check valve leak test procedure appeared to have caused a thermal hydraulic event or the sticking of a safety injection accumulator isolation motor-operated valve. This issue is discussed in further detail in NRC Inspection Report 50-482/92-06 (Section 6).

Maintenance activities, observed by the inspectors, were performed well during this inspection period. An instance of improper material tagging was identified by the licensee, but this appeared to be an isolated case. The licensee's corrective actions were appropriate (Section 7).

The safety injection system was determined to be aligned in accordance with station operating procedures; however, the adequacy of a 2-year review associated with the system checklist was identified as an unresolved item (Section 8).

The licensee maintained a good 10 CFR Part 50.59 program. The licensee was working to improve the consistency of evaluations among plant organizations. Formal training exists for use of screening criteria; however, the training department was planning to develop training on proper performance of safety evaluations. In one instance, part of the basis for not performing a safety evaluation was unjustified. The inspector considered this to be a weakness (Section 9).

A list of acronyms and initialisms is provided in Attachment 1 of this report.

DETAILS

1. Persons Contacted

B. D. Withers, President and Chief Executive Officer
J. A. Bailey, Vice President, Operations
F. T. Rhodes, Vice President, Engineering and Technical Services
O. L. Maynard, Director, Plant Operations
T. M. Anselmz, Licensing Engineer
R. S. Benedict, Manager, Quality Control (QC)
A. B. Clason, Supervisor, Maintenance Engineering
E. W. Creel, Manager, Nuclear Activities, Kansas Gas and Electric
M. E. Dingler, Manager, Nuclear Plant Engineering (NPE) Systems
D. L. Fehr, Manager, Operations Training
R. B. Flannigan, Manager, Nuclear Safety Engineering
C. W. Fowler, Manager, Instrumentation & Control (I&C)
J. E. Gilmore, Supervisor, Operations Training
R. W. Holloway, Manager, Maintenance and Modifications
D. Jacobs, Supervisor, Mechanical Maintenance
R. K. Lewis, Supervisor, Results Engineering
W. M. Lindsay, Manager, Quality Assurance (QA)
R. L. Logsdon, Manager, Chemistry
T. S. Morrill, Manager, Radiation Protection
D. G. Moseby, Supervisor, Operations
D. G. Naylor, Supervisor, Operations Training
W. B. Norton, Manager, Technical Support
C. E. Parry, Director, Quality and Safety
A. L. Payne, Manager, Supplier/Material & Quality
J. M. Pippin, Director, NPE
C. E. Rich, Jr., Supervisor, Electrical Maintenance
B. B. Smith, Manager, Modifications
S. G. Wideman, Manager, Licensing
M. G. Williams, Manager, Plant Support

The above licensee personnel attended the exit interview conducted on March 9, 1992. In addition to the above, the inspectors also held discussions with various other licensee and contractor personnel during this inspection.

2. PLANT STATUS

The plant was at 100 percent thermal power at the start of the inspection period. A reactor trip and turbine trip occurred on February 19, 1992, because of "lo-lo" steam generator (SG) water level, which was caused by an instrument bus failure. The licensee stabilized the plant and cooled it down to Mode 5 (cold shutdown). On February 26, 1992, the plant returned to Mode 3. On February 28, 1992, the licensee identified a leak on a reactor vessel head control rod drive mechanism (CRDM) canopy-seal weld. During the inspection of the leaking canopy seal weld, licensee personnel inside the containment building heard a loud noise and felt movement of the permanent cavity seal ring. Seismic monitor and loose parts monitor alarms were received. The licensee formed an Incident Investigation Team to investigate the cause(s) of the noise and, on February 29, 1992, the plant was cooled down to Mode 5. The plant was in Mode 5 at the end of the inspection period.

3. FOLLOWUP ON PREVIOUSLY IDENTIFIED NRC ITEMS, FOLLOWUP OF LICENSEE EVENT REPORTS AND FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS

3.1 Inspector Followup and Unresolved Items (92701)

3.1.1 (Closed) Unresolved Item (482/9113-03) Discrepancies In Medical Exams

This unresolved item addressed the discrepancies found by the licensee in their operator medical examination program. The deficiencies included a failure to perform a specific test to determine tactile discrimination capability; a failure to perform blood tests to document the absence of hematopoietic dysfunction; and a lack of procedural requirements to review the status of work performance, attendance, and behavioral changes that are documented as part of the fitness-for-duty program.

The inspector reviewed Procedure HR-105A, Revision 1, "Medical Examination for Licensed Personnel," Form KZF-19, Revision 10/91, "Medical History and Physical Examination For Licensed Personnel," and Form KZF-30, Revision 10/91, "Licensed Personnel Medical Examination - Supervisor's Report." No problems were identified. All operators passed the reexamination for the deficiencies described. All current examinations were performed in accordance with the requirements. The inspector randomly selected four files and found the documentation to be in accordance with the subject requirements. The licensee revised the Updated Safety Analysis Report (USAR) to reflect the commitment to Regulatory Guide (RG) 1.134, Revision 2, "Medical Evaluation of Licensed Personnel for Nuclear Power Plants," that endorses American National Standards Institute/American Nuclear Society 3.4, 1983, "Medical Certification and Monitoring of Personnel Requiring Operating Licenses For Nuclear Power Plants." This item is closed.

3.1.2 (Closed) Inspector Followup Item (IFI) (482/9108-01): Reactor Coolant System (RCS) Sample Through Chemical Volume Control System (CVCS) Inlet Sample Line

This IFI addressed the adequacy of an alternate RCS sample point. The licensee compared measurements of liquid RCS samples taken from the RCS Loop 1 hot leg sample point and the CVCS inlet sample point in February 1992. The results of the comparison demonstrated that the CVCS sample location provided representative RCS chemistry samples. This information will be included in the semiannual report that will be submitted in August 1992. This item is closed.

3.1.3 (Closed) IFI (482/9118-02): Discrepancy Found In USAR

This item concerned the issue that the USAR did not include updated information on tritium released into the cooling lake. The licensee provided two reasons why updating Table 11.1-2, "Annual Effluent Releases or Liquid," of the USAR is not appropriate. First, the information presented is a model for licensing purposes and is not intended to represent actual operating data. It is, therefore, considered historical data and does not need to be updated.

Second, the actual releases and resulting offsite doses are calculated and reported as required by the offsite dose calculation manual in accordance with 10 CFR Part 50.36a and Section IV.B.1 of Appendix I to 10 CFR Part 50.

On the basis of discussions with Office of Nuclear Reactor Regulation and Region IV personnel, the licensee's justification was found to be acceptable. This item is closed.

3.1.4 (Closed) IFI (482/9122-01): Ultimate Heat Sink (UHS)

This IFI addressed the NRC followup of licensee activities to ensure the design adequacy of the UHS. The inspector reviewed the following documents: (1) Engineering Study EER 91-EF-03, Revision 0, "Review of the Ultimate Heat Sink Performance With Two ESW Train Operation"; (2) DC-UHS-01-WC, Revision 5, "Mechanical Design Criteria For Ultimate Heat Sink"; and (3) a report prepared by Sargent & Lundy, "Minimum Ultimate Heat Sink Capacity Requirement for Safe Shutdown of One Unit to Meet Present and Future Plant Conditions." The licensee determined that the UHS would have performed its design function in the "as-found" condition even though silting occurred in the channel to the essential service water (ESW) system pumphouse. The maximum level decrease was estimated to be 1.69 feet. The channel depth is normally 5 feet and approximately 2 feet of silt was measured.

New calculations were performed for the UHS based on RG 1.27, Revision 2, "UHS For Nuclear Power Plants." The licensee evaluated the impact of raising the maximum design temperature of the ESW supply to plant components. The USAR is being changed from a maximum permissible temperature of 95°F to state that the maximum design basis temperature of the water supplied will be 95°F. The licensee's calculations indicated that a temperature of 96°F could be expected on three occasions during the 36-day duration following a design-basis event and that the temperature would exceed 95°F for approximately 3 hours. The evaluations concluded that the heat exchangers and coolers would not be sensitive to slight increases in temperature over the short periods of time; therefore, no adverse impact to equipment would occur. The inspector noted that approximately 4°F of the temperature rise is due to solar heating based on the weather conditions that must be assumed.

During Refuel V, the licensee dredged in the vicinity of the ESW pumphouse. A mechanically powered cutter head in front of the suction line was used for the remainder of the UHS channel. The dredging was performed as originally planned except at the 1970 foot elevation on either side of the 80 foot wide UHS channel. Not dredging this portion could result in reducing the time before increased sedimentation occurs in the UHS channel again. However, the licensee has a monitoring program that will note increasing sedimentation rates.

The licensee determined in response to NRC questions that the UHS had in fact lost a useable capacity of 20 million gallons. The buildup in the channel measured 24 inches, particularly near the mouth of the channel. This buildup acted as a dam and resulted in a 70 percent loss of the usable depth of pump suction. The dredging in the channel was designed to reclaim the usable pump suction depth. The sediment buildup did not affect the ability of the UHS to dissipate heat during an accident. The sediment that was dredged was pumped over the cooling lake south baffle dike. This item is closed.

3.1.5 (Open) IFI 482/9136-05: Fuse Control

This item documents fuse control problems identified by the licensee. The inspector reviewed the licensee's evaluation of Industry Technical Information Program (ITIP) Item No. 01715, NRC Information Notice 91-51, "Inadequate Fuse Control Programs." The ITIP response concluded that WCNOC was taking positive steps to resolve fuse-related problems based on the inspections performed by QC. The ITIP was closed, and the Plant Safety Review Committee (PSRC) approved the closure on November 20, 1991. In discussions with NPE personnel, they stated that they were recently made aware of the ITIP status but that the conclusions drawn regarding fuse control were still under review by NPE (see in NRC Inspection Report 50-482/91-36). A Performance Improvement Request (PIR) was generated to determine why this information notice was not reviewed properly. This item remains open.

3.2 Followup on Corrective Action For Violations (92702)

3.2.1 (Closed) Enforcement Action EA 91-003 (Violation 482/9039-01): Failure to Satisfy a Technical Specification (TS) Requirement

This violation addressed the freezing of the safety injection (SI) pump recirculation line. The inspector confirmed that STN GP-001, Revision 7, "Plant Winterization," included a requirement to place the refueling water storage tank (RWST) on recirculation during winter temperature conditions. A requirement to have electrical maintenance check heat-trace current daily to verify proper operation when a freeze protection trouble alarm is activated was included in the procedure. A requirement to calibrate the ambient temperature switches annually is included in INC-C-1001, Revision 5, "Calibration of Switches." The inspector reviewed the QA Surveillance TE: 53359 S-1956, "Freeze Protection." The surveillance included four recommendations for improvement, including referencing the plant winterization procedure in the applicable system procedures, replacing "should" with "shall" in the plant winterization procedure, periodically reviewing essential readings (required reading) to ensure that it is read in a timely manner, and providing additional training on heat-trace systems. The inspectors found these actions to be acceptable. This item is closed.

3.2.2 (Closed) Violation (482/9118-01): Failure to Follow an Approved Procedure

This NRC identified violation pertained to a closed isolation valve for the pressure transmitter located on the residual heat removal (RHR) Pump B discharge piping. The inspector determined that the corrective actions committed to in the violation were acceptable. The lesson plan for general employee training which is being performed during 1992 includes a discussion of controlled procedures and the requirement to adhere to procedures. Licensee requalification training on industry events includes a discussion of this violation.

The memo from the Director of Plant Operations to all station personnel described management expectations stating: "Operations personnel are the only individuals authorized to manipulate valves and operate equipment in the plant unless specifically allowed by procedure or authorized by the control room." This violation is closed.

3.2.3 (Closed) Violation (482/9130-01): Failure to Maintain Proper Air Sampling During Containment Leak Rate Testing

This violation resulted when air was released from containment without required monitoring equipment being operable. The inspector reviewed the change made to STS PE-018, Revision 4, "Containment Integrated Leak Rate Test." The change provided adequate direction in case of monitor inoperability. Additionally, the licensee placed the PIR, that documented the concern and corrective actions related to this violation, into the essential reading program for results engineering personnel as part of the corrective action. The inspector found these actions to be acceptable. This violation is closed.

3.2.4 (Closed) Violation (482/9131-01): Failure to Make Timely NRC Notification

This violation resulted from failing to report an engineered safety features (ESF) actuation in a timely manner. The inspector reviewed the guidance contained in the October 28, 1991, revision to WCGS Standing Order No. 11 on the interpretation of "preplanned" as used when determining if an event is reportable. On the basis of this additional guidance, this violation is closed.

3.3 Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)

3.3.1 (Closed) LER 90-012: Reactor Trip Caused by Steam Generator Atmospheric Relief Valve (ARV) Remaining Open

The immediate corrective actions included closing the ARV by an I&C technician who isolated the nitrogen supply from the actuator. As discussed in NRC Inspection Report 50-482/91-22, the licensee's corrective action included installation of Plant Modification Request (PMR) 03651. This PMR added manual isolation valves on the nitrogen supply line to the ARVs. The inspector verified that the valves installed during Refuel V were added to Checklist (CKL) AB-120, Revision 0, "Main Steam System Lineup." The inspectors found these actions to be acceptable. This item is closed.

3.3.2 (Closed) LER 90-013: Reactor Trip and Main Turbine Trip Caused by High Moisture Separator Reheater Level

The reactor trip resulted from inadequate calibration of two high level alarm switches for the moisture separator drain tanks. These level switches were not calibrated on a scheduled frequency. As a result of concerns expressed in NRC

Inspection Report 50-482/91-11, the licensee's inspection report review group established requirements to calibrate the level switches during each refueling outage. This item is closed.

3.3.3 (Closed) LER 91-003: TS Violation - Failure to Perform American Society of Mechanical Engineers (ASME) Section XI Required Visual Inspection of ASME Code Class 2 Piping

Surveillance Procedure STS PE-048C, "Refueling Pool Skimmer System Pressure Test," did not test a small section of the piping. The root cause was determined to be personnel error during procedure development. The revised procedure was performed during Refuel V. The inspector reviewed the completed procedure and identified no problems. This item is closed.

3.3.4 (Closed) LER 91-010: Containment Emergency Escape Air Lock Hatch Closed Without Having the Required Leak Rate Test Performed Because of Inadequate Administrative Control

This event occurred because of the lack of administrative controls for security system work requests (WRs) affecting power block equipment. Additionally, electricians failed to recognize the requirements for testing the containment escape hatch. The inspector verified that permanent signs posted on the escape hatch doors informed personnel of the notification requirements if the doors were opened. If the containment escape hatch doors were opened, test personnel were required to perform a leak check. The inspector reviewed the changes in Procedure SEC 01-109, Revision 9, "Reporting of Security System Defects and Work Request," to ensure that the shift supervisor was made aware of work to be performed on equipment affecting the power block. The inspector considered that these actions were acceptable. This item is closed.

3.3.5 (Closed) LER 91-021: Voluntary - Emergency Diesel Generating (DG) A Restored With Incorrect Post-Welding Hydrostatic Test Pressure on Jacket Water and Lube Oil Heat Exchangers

The cause of using of the wrong hydrostatic test pressure to test the jacket water and lube oil heat exchangers was determined to be personnel error. To avoid future problems, the licensee enhanced the guidance for determining the correct system design pressure. This guidance was incorporated in Procedure ADM 08-217, Revision 0, "Hydrostatic and Pneumatic Testing." The change required specifying the source document used in determining the system test pressure and provided several sources for obtaining test pressure information. This enhancement was intended to better focus the individual on the information used. This item is closed.

3.3.6 (Open) LER 91-023: Accidental Bumping of 120 Volt Supply Panel Results in ESF Equipment Actuations

The licensee attributed the ESF actuation to maintenance personnel accidentally bumping the cubicle door for Breaker NG 02AF4. At the time of the event, maintenance personnel were working in the area. WR 07164-91 was written to investigate the sensitivity of the ground fault relay, the door of the cubicle, and the breaker. The licensee could not repeat the event. A memo was issued by the maintenance manager informing maintenance personnel of the event, cautioning them about working around plant equipment, and reminding them of the requirement to notify the control room if their actions affected a control device.

During the review of this LER, the inspector noted that LERs 86-044, 87-041, and 89-004 also described ESF actuations that resulted from inadvertent bumping of equipment; however, these LERs are not referenced. The licensee stated that these LERs described bumping that occurred while the equipment in question was being worked on rather than bumping that occurred as a result of work being performed on equipment located in the area. The inspector noted that this LER did not consider the generic implications of other plant equipment that may be trip sensitive because of inadvertent impact. As a result, this item will remain open.

Conclusions

Overall, the inspectors found that the LERs reviewed satisfied the requirements of 10 CFR Part 50.73. However, in one instance, the corrective actions that were described were not expanded to address the generic implications of the event. The inspectors considered this to be a weakness.

3.4 Inoffice Review of Written Reports of Nonroutine Events at Power Reactor Facilities (90712)

The following LERs were reviewed and closed on the basis of complying with the reporting requirements and the acceptability of corrective actions:

3.4.1 (Closed) LER 88-028-01: Individual Receives Skin Dose in Excess of Limits as a Result of Unexpected Hot Particle Contamination

3.4.2 (Closed) LER 89-010-01: Inadequate Programmatic Controls Leads to Personnel Error Resulting in TS Violation

3.4.3 (Closed) LER 89-021: TS Surveillance Requirement Not Satisfied Prior to Equipment Being Returned to Service Because of a Procedural Inadequacy

3.4.4 (Closed) LER 90-021-01: Seismic Questions Concerning the Governor Speed Control Conduit Causes Inoperability of Turbine Driven Auxiliary Feedwater Pump

3.4.5 (Closed) LER 91-01-001: TS Violation - Leak in Rupture Disc Allows an Unplanned Release of Waste Gas Decay Tank Without Prior Sampling

3.4.6 (Closed) LER 91-017-01: Failure to Follow Procedure by Propping Door Open Results in Potential Inoperability of Fuel Building and Auxiliary Building Emergency Exhaust Systems

The memo from the Director of Plant Operations to all station personnel described management expectations stating: "Operations personnel are the only individuals authorized to manipulate valves and operate equipment in the plant unless specifically allowed by procedure or authorized by the control room." This violation is closed.

3.2.3 (Closed) Violation (482/9130-01): Failure to Maintain Proper Air Sampling During Containment Leak Rate Testing

This violation resulted when air was released from containment without required monitoring equipment being operable. The inspector reviewed the change made to STS PE-018, Revision 4, "Containment Integrated Leak Rate Test." The change provided adequate direction in case of monitor inoperability. Additionally, the licensee placed the PIR, that documented the concern and corrective actions related to this violation, into the essential reading program for results engineering personnel as part of the corrective action. The inspector found these actions to be acceptable. This violation is closed.

3.2.4 (Closed) Violation (482/9131-01): Failure to Make Timely NRC Notification

This violation resulted from failing to report an engineered safety features (ESF) actuation in a timely manner. The inspector reviewed the guidance contained in the October 28, 1991, revision to WCGS Standing Order No. 11 on the interpretation of "preplanned" as used when determining if an event is reportable. On the basis of this additional guidance, this violation is closed.

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Inspection Report 50-482/91-11, the licensee's inspection report review group established requirements to calibrate the level switches during each refueling outage. This item is closed.

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This event occurred because of the lack of administrative controls for security system work requests (WRs) affecting power block equipment. Additionally, electricians failed to recognize the requirements for testing the containment escape hatch. The inspector verified that permanent signs posted on the escape hatch doors informed personnel of the notification requirements if the doors were opened. If the containment escape hatch doors were opened, test personnel were required to perform a leak check. The inspector reviewed the changes in Procedure SEC 01-109, Revision 9, "Reporting of Security System Defects and Work Request," to ensure that the shift supervisor was made aware of work to be performed on equipment affecting the power block. The inspector considered that these actions were acceptable. This item is closed.

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3.4.6 (Closed) LER 91-017-01: Failure to Follow Procedure by Propping Door Open Results in Potential Inoperability of Fuel Building and Auxiliary Building Emergency Exhaust Systems

3.4.7 (Closed) LER 91-026: Unplanned ESF Actuation Resulting From Radiation Monitor GK RE-004 Not Fully Bypassed When Breaker was Deenergized

4. PROMPT ONSITE RESPONSE TO EVENTS AT OPERATING POWER REACTORS (93702)

4.1 Reactor Trip

On February 19, 1992, a reactor trip occurred when the safety-related 120 volt AC Instrument Bus NN01 was deenergized. The inspector verified that the plant was stabilized in Mode 3. The event was preceded by the receipt of Annunciators 25A, "NN01 Undervoltage," and Annunciator 25B, "NN11 Undervoltage." The operators entered Off Normal Procedure OFN 00-021, Revision 7, "Loss of Vital 120 volt AC Instrument Bus." The shift supervisor directed the turbine building watch to energize Bus NN01 from Transformer XNN05. The reactor operator noted that all instrumentation supplied from Bus NN01 had failed. The instrumentation included power range and intermediate range nuclear instruments; the Controlling Pressurizer Level Channel 459, Pressurizer Pressure Channel 455, Chlorine Monitor GK AIT-3, and various other instruments. Since the pressurizer level channel failed low, the letdown isolation valves closed and the charging flow increased. The positive displacement pump (PDP) was running at the time of the event; however, when the operator selected Pressurizer Level Channel 460, the PDP speed reduced to slow. The PDP tripped because of low oil pressure. The PDP operates with a constant speed motor. Pump speed is changed by increasing or decreasing the fluid coupling between the motor and pump. When the automatic runback occurred, the pump controller slowed the pump too fast (overcompensated) which lowered the oil pressure below the low oil pressure setpoint. An operator started Centrifugal Charging Pump (CCP) A when he noticed that the PDP was not operating. The posttrip review determined that cooling water to the reactor coolant pump (RCP) seals was stopped for approximately 42 seconds.

The inspector determined that additional component actuations occurred when Bus NN01 was lost. Level instrumentation for the component cooling water surge tank failed low, which resulted in the start of another component cooling water pump. Steam generator (SG) pressure transmitters, steam flow instruments, and turbine impulse pressure instruments also failed low. This resulted in a reduction in main feedwater pump speed, which caused decreasing SG water level. Approximately 2 minutes after receipt of the undervoltage alarms, a reactor trip occurred on "lo-lo" SG A level. The operators entered Emergency Procedure EMG E-0, Revision 2, "Safety Injection," verified a safety injection (SI) did not occur, and proceeded with Emergency Procedure ES-02, Revision 2, "Reactor Trip Response."

The licensee determined that all ESF equipment functioned as required. Components that failed to operate as expected included the improper operation of three steam dump valves. The operators also had difficulty in starting the main turbine lift pumps, and the RCPs lost seal cooling for a short period following the trip of the PDP and before a CCP was started. The licensee conducted the posttrip review in accordance with Procedure ADM 02-400, Revision 8, "Posttrip Review." The licensee classified the trip as a Condition II, which indicated the cause of the trip was known and corrective actions implemented.

The inspectors monitored the posttrip review presentation given to the Director of Plant Operations. The operations supervisor determined that Procedure OFN 00-021, Revision 7, "Loss Of Vital 120 volt AC Instrument Bus," contributed to the trip. Procedure OFN 00-021 required the operator to take manual control of the main feedwater pump to maintain SG levels rather than ensuring that all necessary instrumentation was transferred to alternate controlling channels. To aid the operator in making these transfers, the supervising operator recommended that, for each instrument channel, a designation of the applicable power supply be added to the control boards. A PIR was issued to document this recommendation. Another PIR was issued to address procedure changes warranted by the problems with the main turbine lift pump CUNO filters since this prevented placing the turbine on the turning gear. A third PIR was issued for changes in the posttrip review requirements for obtaining a sequence of events printout. Human Performance Evaluation System Report 92-002 was generated to investigate whether any changes to procedures or control room aids could have prevented the reactor trip. Hardware Failure Analysis Report (HFAR) RE 92-001 was generated to address the synchronizing card failure in the inverter that supplied the 120 volt AC instrument bus. NPE evaluated the impact of the loss of RCP seal cooling for the 42-second period and determined that no detrimental effects occurred.

Equipment repaired included safety-related instrument inverter circuit cards, the steam dump valves, and a relief valve on No. 7 feedwater heater. This reactor trip will be reviewed further following the issuance of the LER for this event.

Conclusions

Operators responded well following the reactor trip caused by the loss of an instrument bus. The operations supervisor performed a good, thorough posttrip review. The review identified weaknesses in the offnormal procedure for loss of an instrument bus. The review determined that the power supply for each instrument should be specified on the control boards.

5. OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with license and regulatory requirements and that the licensee's management control systems were effectively discharging the licensee's responsibilities for continued safe operation. The inspectors monitored licensee activities related to: restoration of Inverter NN11, actuation of seismic monitors and loose parts monitor (LPM), permanent cavity seal ring, ESF actuation, operability of ESW strainers, overpressurization of PDP discharge piping, emergency light found inoperable, discussions on dose equivalent Iodine (DEI), unexpected transfer of RWST inventory to the RCS, chlorine monitors, digital rod position indication (DRPI) deviation annunciator, inadvertent release in the radwaste building, inadequate control room ventilation lineup, SI accumulator boron concentrations, DG missile doors, and organizational changes. The methods used to perform this inspection included direct observation of activities and equipment, control room operations, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety-system status and limiting conditions for operation, corrective actions, and review of facility records.

5.1 Restoration of Inverter NN11

During the restoration of NN11 to its normal lineup, the breakers for BG LCV-112C, volume control tank outlet valve; and BN LCV-112D, the CCP suction isolation valve from the RWST, tripped when the operator tried to reopen them. At the same moment the operator tried to open the valves, the valve control logic generated a close signal. These opposing logic signals caused the breaker to trip. Additionally, the SG A ARV failed open. Investigation revealed that Pressure Transmitter AB PT-1 loses power when NN11 is lost. When NN11 was restored, the pressure transmitter spiked "high" causing the ARV to open. Operations personnel were dispatched to close the ARV and close the breakers for the two valves. Further review disclosed that the equipment functioned as designed. Operations Procedure SYS NN-131, Revision 8, "120 volt AC Instrument AC (Class 1E) Energization," did not provide the operator guidance on how to avoid these actuations. A procedure change was approved on February 26, 1992, to increase the detail in SYS NN-131 and SYS NN-332, Revision 0, "120 volt AC Instrument AC (Class 1E) Deenergization," to preclude further problems.

5.2 Actuation of Seismic Monitors and LPM

On February 28, 1992, while in Mode 3, the control room received Annunciator 98C, "R Spectrum OBE Exceed," that indicated operating basis earthquake (OBE) acceleration limits were exceeded. Annunciator 98E, "Seismic Recorder On," alarmed which indicated that the strong motion seismic instrumentation system detected acceleration greater than or equal to 0.01 g (feet per second). Also, the LPM received indications on 10 of 12 LPM channels. The operators noted that no major evolutions were in progress and that no RCS parameters or containment parameters changed. QC personnel in the containment reported that they heard a loud "noise" and felt the permanent cavity seal they were standing on "move." After discussions with Region IV personnel, the licensee issued a letter to Region IV confirming that they would brief the NRC on the results of the their incident investigation team's findings prior to entering Mode 2. An NRC special team inspection was initiated on March 6, 1992, and was ongoing at the end of the inspection period. The results of this inspection will be documented in NRC Inspection Report 50-482/92-06.

5.3 Permanent Cavity Seal Ring

Following the noise that occurred inside containment on February 28, 1992, the licensee performed a walkdown of the permanent cavity seal ring (which was recently installed during the fifth refueling outage) to determine whether any offnormal conditions existed. During the walkdown, the licensee determined that a boron impregnated polyethylene material, Type 207, had flowed from the cavity seal "basket" corners and collected on the cavity seal insulation and RCS piping. The cavity seal ring was constructed with "baskets" that hung under the seal ring. The "baskets" (which are used for shielding) contained approximately 8 inches of concrete and 4 inches of borated polyethylene. The licensee conducted walkdowns and determined additional locations where the melted polyethylene material contacted. They also began an investigation of its effect on equipment that it came into contact with. The polyethylene was in three forms: (1) translucent, (2) dark brown, and (3) charred black. The licensee determined, after reviewing records and discussions with the vendor, that the polyethylene has flame retardant additives that are nontoxic and produce water vapor. Because polyethylene is a simple hydrocarbon, the material releases mainly hydrocarbon and carbon dioxide upon burning.

After reviewing the design calculations, the licensee determined the largest source of heat was inleakage of air at the corners of the vertical and horizontal insulation. An additional heat source was the gap between the vessel head and the cavity seal ring. The licensee also determined some cooling of the cavity seal ring was reduced because of a "chimney effect" at the excore detector wells. None of these deficiencies were detected during the postmodification testing following the installation of the seal ring.

The licensee's corrective actions included: (1) placing insulation in the corner where the vertical and horizontal insulation meets in order to ensure the corner acts as a line source of heat as originally designed, (2) placing insulation between the reactor vessel and the permanent cavity seal to fill that space, and (3) placing insulation and sheet metal caps at the detector wells to eliminate the "chimney effect" to ensure proper ventilation. Additional corrective actions included redistributing air flow to enhance proper cooling and placing stainless steel sheets around the reactor vessel piping to preclude any polyethylene from contacting the piping. The inspector reviewed the WRs that implemented the corrective actions for adding insulation, placing stainless steel sheet metal over RCS piping, and i talling access covers. No problems were identified.

The licensee determined the effects on equipment qualification of the head vent valves, Rosemount transmitters, electronic circuit boards, and conduit seals. The licensee assumed a loss of all the polyethylene and calculated the new dose rate. The new dose rate was calculated to be 1400 mrem per hour. Previously measured dose rates were approximately 200 mrem per hour. Approximately 2 cubic feet out of 65 cubic feet of polyethylene was lost. The licensee will conduct increased neutron radiation surveys in order to determine the actual dose rates while the unit is at power.

The licensee determined that the design basis temperatures for the concrete were not exceeded. The licensee contracted with a test laboratory to evaluate the chemical content of the various stages of polyethylene. Upon receipt of the lab results, the licensee determined that the only constituent of concern could be the 70 parts per million (ppm) fluoride concentration. However, most of the concentration was volatile and evaporated. The remaining material was removed from the RCS piping prior to plant heatup. Followup by the NRC of the effectiveness of the licensee's actions and their long-term corrective actions will be tracked as IFI 482/9202-01.

5.4 Inadvertent ESF Actuation

On February 29, 1992, as an I&C technician lifted a lead to disable the feedwater isolation signal (FWIS), a feedwater isolation occurred. Upon investigation, the licensee determined that the technician accidentally touched the lead to metal while removing the lead from the terminal strip. After reviewing the drawings and the vendor manual, the licensee determined that this was the cause of the inadvertent FWIS. A PIR was initiated to ensure other methods were researched for landing and lifting leads related to disabling the FWIS. Further inspection followup will be performed following the issuance of LER 92-004.

5.5 Overpressurization of PDP Discharge Piping Results in Relief Valve Damage

On January 31, 1992, the system engineer responsible for the CVCS noted during review of VT-2 inspection results that the pressure in the Class 2 piping had reached 2900 pounds per square inch (psi) on January 10, 1992. This was 100 psi greater than the design pressure, but less than the 110 percent (3080 psi) hydrostatic test pressure. A PIR was written to determine the root cause of the overpressurization. A shift supervisor knowledgeable of the evolutions in progress performed the evaluation. The shift supervisor concluded that the overpressurization occurred during performance of STS BG-004, Revision 8, "RCS Inservice Valve Test." Procedure STS BG-004 provided instructions to adjust the RCP seal injection throttle valves to limit total seal injection flow. The flow would be limited to approximately 80 gallons per minute (gpm) during an SI with one CCP operating at runout flow, or approximately 124 gpm with two CCPs operating.

The licensee determined that the operators performing the test verified that they met the initial conditions prescribed by the procedure. The operator determined from existing differential pressure that maximum flow to the RCP seals was being exceeded. The operators adjusted the seal injection throttle valves. This was the only flow path that existed with normal charging and letdown secured. Closing the throttle valves rapidly increased the charging line pressure since the seal injection flow path was the only available path. Charging system pressure quickly exceeded the PDP relief valve setpoint of 2735 pounds per square inch gage (psig). However, the operator did not realize the setpoint had been exceeded. When the charging pressure gauge began oscillating, the operators reopened the RCP seal injection throttle valves and suspended the test. At that time the seal injection flow was 42-44 gpm, the relief flow was approximately 5-7 gpm, and the charging system pressure was 2900 pounds per square inch gage (psig). The auxiliary building watch noticed the relief valve was leaking. Subsequently, the PDP was removed from service and CCP A was started. The PDP discharge pipe was overpressurized for approximately 15 hours.

The root cause analysis revealed that the test procedure failed to properly capture vendor design information as specified in a reference document. The vendor specified that charging and letdown system be aligned in normal and in-service. The licensee's procedure stated flow should be balanced, which allowed both charging and letdown to be secured. The vendor document specified that the RCS should be at normal operating pressure (NOP) and normal operating temperature (NOT). The licensee procedures specified the plant should be in Modes 1, 2 and 3; however, for a significant period of the time, the plant is not at NOP and NOT when in Mode 3. The procedure had no precaution to indicate a maximum system pressure while throttling the seal injection throttle valves. Additionally, none of the control room operators realized that the relief valve setpoint had been exceeded even though there was available indication. This is indicative of a training weakness. This is an additional recent example of a plant event that was caused by an inadequate procedure. The inadequacy of STS BG-004 is a violation of Technical Specification 6.8.1.a for failure to have an adequate test procedure (482/9202-02).

5.6 Emergency Light Found Inoperable

On a routine tour of the auxiliary building on February 14, 1992, the inspectors noted that Emergency Light A-65 was not energized. This information was given to plant management and, subsequently, the light was reenergized on February 18, 1992. After electricians determined the light was inoperable because the fuse was not installed, electrical maintenance personnel wrote a PIR. Discussions with personnel involved revealed that individuals who performed the annual 2-hour test failed to properly restore the light. The inspectors considered this to be another recent example of inattention to detail.

5.7 High DEI Levels

On February 12, 1992, a conference call among WCGS, Region IV, and Office of Nuclear Reactor Regulation personnel was conducted concerning the increasing levels of DEI. Licensee personnel explained that although DEI levels were increasing, Iodine-134 and Iodine-131 met expected values. On the basis of analysis and discussions with licensee personnel, the licensee concluded that the cause of increased DEI was the presence of tramp uranium and not failed fuel. Tramp uranium is residual uranium in the RCS from previous failed fuel or uranium dioxide on the surface of the fuel. WCGS plans to revise Administrative Procedure ADM 01-221, Revision 1, "Failed Fuel Action Plan," to establish action levels on the basis of DEI and Iodine-131. After the reactor trip of February 19, 1992, no spike was noted in DEI levels. This indicated that fuel failures were not present.

5.8 Unexpected Transfer of RWST Inventory to the RCS

On February 23, 1992, a control room operator discovered that 12,000 gallons of water drained from the RWST to the RCS. The plant was in Mode 5 with RCS temperature and pressure at 122°F and 0 psig, respectively. The licensed operator identified the decreasing level while taking control board readings in accordance with Procedure STS CR-002, Revision 15, "Shift Log for Modes 4, 5, and 6." Between his readings, RWST level dropped from 96 percent to 92 percent in 8 hours. The operator was alerted because he knew that no water transfer activities, nor any other plant evolutions, were ongoing that could cause this level decrease.

The operator determined the possible drain paths from the RWST were through either the cold leg SI injection valve, EM HV-8835, or the fuel pool cleanup to recycle holdup tank isolation valve, EC-V081. Upon discovering EM HV-8835 "open," the operator immediately closed the valve and verified EC-V081 closed. After closing EM HV-8835, RWST level stopped decreasing.

At the time of the event, the operators were draining the RCS to the 2016 elevation for repairs to be conducted on a leaking core exit thermocouple penetration conoseal (see Section 7.1). The inspectors determined that the operators completed the last steps of GEN 00-006, Revision 18, "Hot Standby to Cold Shutdown," and started performing GEN 00-007, Revision 16, "RCS Drain Down," to draindown the RCS in order to perform the repair. A caution statement in GEN 00-006 directed the operator to ensure EM HV-8835 was closed prior to lowering RCS pressure below 100 psig to avoid draining the RWST to the RCS through the SI pumps. Because reactor pressure was maintained around 350 psig for approximately 35 hours to degas the RCS, the operators failed to reread and follow the caution. Additionally, GEN 00-007 included no information for closing the valve. The root cause was determined to be a failure to specify closing the valve at 100 psig as a procedure step versus a caution. The licensee initiated PIR 92 OP-192 to ensure that corrective actions were implemented to prevent recurrence. This is another recent example of an inadequate procedure and the second example of Violation 482/9202-02.

5.9 Chlorine Monitors

During the last quarterly surveillance test, the licensee experienced problems calibrating the chlorine monitors. One problem was the ability of the chlorine monitors to span correctly. Another problem was with the chlorine permeation devices. Chlorine permeation devices are one-inch diameter by five-inch long cannisters filled with a substance that generates chlorine gas at a set rate. They are used during the calibration of the chlorine monitors. Because these devices were procured from a commercial vendor, the licensee performed a receipt inspection test. The licensee's test generated a curve that documents permeation rate using the same methodology as the vendor. The licensee's data was more conservative in that the permeation rate was lower than the vendors in all instances except one. The chlorine monitors were sent to Wyle laboratory for qualification testing, as part of the licensee's commercial grade dedication process; however, Wyle had similar problems generating a curve with the same permeation rate as the vendor. Operators placed the control room ventilation system in a control room ventilation isolation signal (CRVIS) lineup when both surveillance tests became overdue. The tests became overdue because the licensee could not get a permeation device to operate properly. The Director of Plant Operations required an increased testing frequency because of chlorine monitor [illegible]bility.

On February [illegible], 1992, Chlorine Monitor GK AIT-3 was tested and the monitor was found difficult to calibrate. Chlorine Monitor GK AIT-2 was out of span; consequently, operators placed the control room ventilation system in a CRVIS lineup on February 13, 1992 (see Section 5.12). Both monitors were restored on February 15, 1992. On February 28, 1992, both Monitor GK AIT-3 and Monitor GK AIT-2 were found out of span and recalibrated.

The licensee has developed modifications and budgeted resources to eliminate chlorine water treatment systems. PMR 3493 will change the circulating water treatment to sodium bromide from chlorine. PMR 3518 will implement the same change on the ESW system.

5.10 DRPI Deviation Annunciator

On January 18, 1992, the operators declared Annunciator 79D, "Delta Flux Out Of Band," inoperable after licensee personnel failed two of four channels "high" without receiving the expected alarm. Because the operators could not be alerted to an offnormal condition with a delta flux deviation, the operators began logging the delta flux in accordance with Procedure STS SF-002, "Core Axial Flux Difference." I&C technicians determined that the annunciator was not functioning because a summing amplifier on a computer card had failed. The computer card was repaired on January 24, 1992.

On January 24, 1992, licensee personnel determined that the computer failed to identify that rod position points were "bad" when power to the cabinet that housed DRPI failed. Subsequently, the DRPI deviation annunciator, Annunciator 79C, was declared out of service. Operators entered Offnormal Procedure OFN 00-023, Revision 8, "Loss Of NPIS Computer," and TS 4.1.3.2. After entry into the offnormal procedure, control room personnel logged rod position for the affected control rods every 4 hours. At the request of reactor engineering personnel, Control Bank D rods were stepped in and out four steps. The DRPI reading on the control panel changed, but no change was seen by the computer and no deviation alarm occurred. Both hardware and software changes were required to correct the computer deficiency. The hardware change was installed on February 19, 1992. The software change will ensure that affected rods are printing out NCAL (not calibrated) instead of "GOOD" when the annuciator is received. The licensee implemented this change, but acceptance testing needs to be performed with the rods withdrawn. The licensee will perform the test after reaching Mode 2.

5.11 Inadvertent Release In Radwaste Building

On March 3, 1992, there was an inadvertent waste gas release in the radwaste building when a relief valve lifted. During performance of System Procedure SYS HA-200, Revision 8, "Waste Gas System Startup and Shutdown," the operator incorrectly placed a gas decay tank on line when it was in the high pressure mode. Chemistry personnel were notified as required by the offsite dose calculation manual because the tank was not sampled prior to the event. The dose calculations estimated exposures of 0.25 millirem (mrem)/year to the whole body and 1.16 mrem/year to the skin. These values were well within the exposure acceptance limits of 500 mrem/year to the whole body and 300 mrem/year to the skin. This release will be included in the semiannual release report. The licensee added a caution prior to Step 4.7.1 to ensure that the system was in the proper mode prior to realignment. Inadvertent releases have occurred previously on a number of occasions. This is the third example of Violation 482/9202-02 for failure to have an adequate procedure.

5.12 Inadequate CRVIS Lineup

On February 13, 1992, the control room chlorine detection systems were inoperable because Detectors GK AIT-2 and GK AIT-3 failed to calibrate as specified in Procedures STS IC-280A, Revision 11, "Analog Channel OP Test CTRL RM CL DET Train A," and STS IC-280B, Revision 9, "Analog Channel OP Test CTRL RM CL DET Train B." The licensee entered TS 3.3.3.7 and initiated a CRVIS using a Train B system lineup when both chlorine monitors were declared inoperable. When in a manually initiated CRVIS lineup on Train A and B, the following must be initiated for a single train. The normal ventilation supply and exhaust flow paths are isolated, sealing off the control building; a control room air conditioning unit is started and aligned in a recirculation flow path; part of the recirculation flow is diverted through a filter absorber unit for cleanup; a pressurization fan is started to ensure that 1/4-inch water gauge positive pressure is maintained; and all attendant dampers are positioned as necessary to maintain the lineup.

Subsequently, control room operators started the Train A air conditioner and stopped the Train B air conditioner so that results engineering personnel could conduct a vibration test on the Train A air conditioner. This took the control room out of the CRVIS lineup. The error was discovered 12 hours later by a different operating crew. This was contrary to TS 3.3.3.7 Action B. This requires that, with both chlorine monitors inoperable, place the control room ventilation in a CRVIS lineup within 1 hour. The inspector reviewed an evaluation of the event conducted by the licensee. The evaluation determined that, if an SI signal, fuel building isolation signal, or manual initiation had occurred, complete realignment of CRVIS Trains A and B would occur. Therefore, the system would have performed it's intended function. This issue will be reviewed further following the issuance of the LER for this event.

5.13 High SI Accumulator Boron Concentrations

On February 1, 1992, the licensee determined that the SI accumulator boron concentration for the four SI accumulators were: A-2496 parts per million (ppm), B-2496 ppm, C-2494 ppm, and D-2499 ppm. The TS upper limit is 2500 ppm. The licensee began an investigation to determine why the concentrations were high.

From discussions with the licensee, the inspector determined that the licensee had taken samples at the outlet of the RWST and on the discharge of the SI pump. The boron concentration at these locations was approximately 2470 ppm. Additionally, the licensee considered the effects of instrument accuracy. The instruments have a 1 percent accuracy that could account for the high readings since, at the end of the Refuel V outage, the RWST concentration was 2470 ppm.

The licensee drained and refilled the SI accumulators during the unscheduled shutdown. After refilling the accumulators, the chemistry sample determined that the boron concentrations were: A-2437 ppm, B-2445 ppm, C-2435 ppm, and D-2433 ppm.

5.14 Pressurizer

On February 21, 1992, during the plant cooldown, after the licensed operators took the pressurizer solid, an excessive pressurizer heatup rate occurred for a short period. The operators had completed equalizing CVCS charging and letdown to maintain 350 psi in the RCS. As pressurizer temperature increased, an operator turned the pressurizer heaters off and initiated pressurizer spray. Since the heatup continued, the operator increased pressurizer spray. For a 15-minute period as spr was increased, the heatup rate increased from 24°F to 308°F for a heatup rate 257°F per hour. When pressurizer spray was stopped, the heatup slowed to less than 8°F per hour.

Engineering performed an evaluation of the temperature changes over a 1-hour window around the transient. Engineering concluded that the structural integrity of the pressurizer walls and the pressurizer nozzles were not affected since the heatup transient was short in duration. The root cause was the method that operations personnel used to cool down the plant while preparing to enter Mode 5. With only one RCP in operation, engineering determined insufficient cooling or mixing occurred in the upper regions of the pressurizer. Higher flow rates or cooler water should resolve the problem. PIR OP 92-0191 was initiated to track resolution of the issue. Recommendations provided by Engineering to ensure adequate mixing and cooling included: (1) using auxiliary pressurizer spray if the RCPs are not operating, and (2) limiting pressurizer heatup and cooldown rates to 30°F and 50°F, respectively.

On February 28, 1992, during the plant cooldown, Engineering monitored various parameters affecting the pressurizer as operators placed the RCS into solid plant operations. Both the cooldown and heatup hourly rates as specified in TS 3.4.9.2 for the pressurizer were exceeded. Because the transients were less than 10 minutes in duration, however, Engineering determined there was insufficient time for heat energy to transfer to the pressurizer wall or nozzles.

The licensee determined that the temperature rate changes for both occurrences were created by insurges and outsurges of water from the pressurizer which were created by sudden changes in spray flow or a mismatch between charging and letdown flows. The inspector determined from discussions with the licensee that they had contacted the vendor about the consequences of temperature transients in the pressurizer. The vendor concurred with the licensee's evaluation that there was no effect on the integrity of the pressurizer walls or nozzles. In 1991, the vendor owner's group initiated a pressurizer insurge/outsurge program to evaluate methods to minimize pressurizer insurges and outsurges.

5.15 DG Missile Doors

On February 4, 1992, during performance of QC Surveillance S1963, "Combustible Permits," a QA auditor determined that the missile doors for both DG rooms were open at the same time. The auditor noted that combustible materials were located near the doors and that Combustion Permit 92-04 allowed the use of painting materials in this area. This concern was raised to the shift supervisor who determined that having both doors open simultaneously exposed the DGs to the same missile and fire hazards. The licensee made a 4-hour report in accordance with 10 CFR Part 50.72.b.2.iii and 10 CFR Part 50, Appendix R, Subsection 3.6.a. Operators had the security officer close DG Room B missile door.

The licensee determined that both doors were opened without notifying the control room; however, a security officer was previously posted in accordance with procedures. From discussions with the licensee, the inspector determined that both missile doors were opened so that craft personnel could transfer scaffolding material from DG Room A to DG Room B.

The licensee subsequently withdrew the report after performing an evaluation of the event. The inspector reviewed the licensee's evaluation that determined there was no basis for reportability. The licensee determined that the small quantity of combustible material outside the doors and the distance between the doors (approximately 30 feet) prevented a flame from affecting both rooms simultaneously.

The missile concern was based on externally generated missiles, such as from a tornado. The inspector reviewed security department and operations department procedures and interviewed various personnel. The inspector determined that sufficient controls were in place to ensure that during inclement weather sufficient warning will occur and procedures will provide for closure of external missile doors. Notwithstanding the above, the inspector considered the lack of control over the DG missile doors to be a weakness. The licensee issued PIR 92-0134 to ensure the determination of the root cause.

5.16 Recent Organizational Changes

During this inspection period, the licensee implemented several organizational changes. The licensee implemented the changes to improve communications, increase effectiveness, and provide for better management oversight. The Vice President of Operations relocated inside the protected area to ensure easier access by personnel reporting to him. The Vice President of Engineering and Technical Services relocated into the engineering building so that he could provide better oversight of engineering activities. The Manager of Technical Services (emergency planning, environmental management) relocated from the corporate office to the site in order to provide for better coordination of the emergency planning activities. The licensee combined part of the compliance group with the licensing group. This consolidated common functions under one supervisor, thus eliminating duplication of effort. Other personnel who worked in compliance will conduct performance monitoring of plant activities such as PIRs and performance indicators.

Conclusion

One violation for failure to have appropriate procedures was identified. This violation pertains to three plant events that were caused by inadequate procedures. These issues are similar to issues identified in NRC Inspection Report 50-482/91-36 and are indicative of a declining trend in both personnel performance and procedural adequacy. In addition, an inadvertent FWIS occurred as a result of personnel error, an emergency light was left deenergized following a preventive maintenance activity, and both DG fire doors were open simultaneously. These appear to be three more examples of inattention to detail. A special inspection was dispatched to investigate the February 28, 1992, noise inside containment event, and the results of this inspection will be documented in NRC Inspection Report 50-482/92-06. Licensee long-term corrective actions associated with the permanent cavity seal ring melted borated polyethylene will be tracked by an IFI. The licensee's actions associated with the excessive pressurizer heatup rate were appropriate.

6. SURVEILLANCE OBSERVATIONS (61726)

The purpose of this inspection was to ascertain whether surveillance of safety-significant systems and components was being conducted in accordance with TS. Methods used to perform this inspection included direct observation of licensee activities and review of records.

6.1 RHR Pump Surveillance Testing

The inspector observed the performance of STS EJ 100A, Revision 8, "RHR System Inservice Pump A Test." No problems were noted with the vibration testing of the pump motor or the check valve flow testing. All values met the acceptance criteria specified in the procedure. The inspector noted upon entering the room that deconning tools were leaning up against the sump pumps located in the corner of the room. The inspector noticed that the procedure for removal of protective clothing at step-off pads was not followed by two people leaving the area. Both the presence of the deconning tools and inadequate removal of protective clothing were brought to the attention of the radiation protection manager. Both items were discussed at his supervisors' meeting. The licensee cleaned up the area after being notified by the inspector.

In addition, the inspector noted that results engineering personnel climbed over the operating pump to obtain motor vibration data. This personnel safety hazard was brought to the attention of safety personnel who determined that the engineer's supervisor expected scaffolding to be erected prior to taking motor vibration readings. The licensee will evaluate the need for scaffolding prior to taking the next set of vibration readings. The safety group and the results engineering manager intend to perform an industrial safety review of the hazards to determine permanent corrective actions.

6.2 RCS Leak Rate Calculations

On February 12, 1992, the unidentified RCS leakage rate was determined to be 0.66 gpm. The leak rate had been increasing during the previous 8 days. The inspector determined from discussions with the licensee that they suspected the leakage was through a PDP plunger. The Director of Plant Operations was kept notified by the shift supervisor of the increasing leak rate. On the afternoon of February 12, 1992, at the direction of management, the leak rate test, STS BB-004, Revision 8, "RCS Water Inventory Balance," was performed with the PDP isolated. The unidentified leakage was determined to be 0.052 gpm. On

February 28, 1992, the unidentified leakage was 0.696 gpm with the PDP running. In accordance with management direction, the PDP was isolated and the leak rate test was reperformed. Unidentified leakage was measured at 0.3218 gpm.

6.3 RCS/Emergency Core Cooling System Check Valve Testing

On February 27, 1992, the licensee performed STS PE-019E, Revision 7, "RCS Isolation Check Valve Leak Test," as a required by TS. The test engineer was knowledgeable and maintained good coordination with the control room operator while conducting the test. After check valve testing was completed on Check Valve BB V-8948D, SI accumulator to Loop 4 check valve, a loud "noise" was heard and Alarm 98C (seismic monitor), "R SPCTRM OBE EXCEEDED," was received when opening the SI accumulator isolation valve, EP HV-8808D. The licensee performed an initial evaluation and walkdown on pipes, supports, valves, and motor operators. No visible signs of damage were noted. The licensee initially attributed the noise to cohesion of the valve disc to the seat, hydraulic differential pressure across the valve, and the rate at which the valve was opened; however, their investigation was still in progress at the end of the inspection period. They were also considering whether the noise was attributed to a thermal hydraulic event in the SI line.

The "noise" associated with opening the accumulator isolation valves had previously occurred as discussed in NRC Inspection Report 50-482/91-36. The cause of this noise appears to be an inadequate surveillance procedure; however, this issue will be discussed in detail in NRC Inspection Report 50-482/92-06.

Conclusion

The inspector noticed that two people failed to follow proper procedures for removal of protective clothing. The failure to install scaffolding prior to the surveillance is considered a weakness. An inadequate check valve leak test procedure appears to have resulted in motor-operated valve binding or a thermal-hydraulic event in an SI accumulator discharge line.

7. MONTHLY MAINTENANCE OBSERVATIONS (62703)

The purpose of inspections in this area was to ascertain that maintenance activities on safety-related systems and components were conducted in accordance with approved procedures and TS. Methods used in this inspection included direct observation, personnel interviews, and records review. Observations of selected maintenance activities are provided.

7.1 RCS Pressure Boundary Leakage Through Abandoned Incore Thermocouple

On February 20, 1992, during a walkdown of components inside containment, licensee personnel determined that a spare thermocouple sheath protruding from a conoseal was leaking. A second inspection determined that primary coolant seeped from the thermocouple conduit. The licensee considered the leak as pressure boundary leakage.

NPE engineers determined that the sheath developed a leak internal to the reactor vessel, allowing primary coolant to enter the conduit and to exit the cut-off end of the cable. The engineering disposition provided three separate methods for repairs to the conduit, specified cleanliness levels, and recommended that a visual inspection be performed at normal operating temperature and pressure. The licensee developed detailed work instructions necessary to cap the stainless steel tubing and stop the seepage. The technicians repairing the leak referred to the Swagelock vendor manual instructions while performing the job. The technicians cut a 1/8-inch conduit, installed a new reducing union, and installed a 1/8-inch cap. Proper cleanliness levels were maintained as specified. QC provided complete coverage of the work activity. A subsequent walkdown at normal operating conditions determined that the capped tubing was not leaking. Additionally, a hardware failure analysis will be conducted to identify the cause of the thermocouple cable sheath failure.

7.2 Spare CRDM Canopy Seal Leakage

On February 28, 1992, during the heatup following a forced outage, a QC inspector identified a leaking canopy seal weld at a spare CRDM (position No. 25) on the rector vessel head. The licensee determined the leakage to be pressure boundary leakage and made preparations to cool down and depressurize the plant to repair the leakage. The licensee entered TS 3.4.6.2.a, which allowed no pressure boundary leakage. The licensee subsequently determined that the leakage was not pressure boundary leakage because the connection for the spare CRDMs was a threaded cap that was seal welded to prevent backing off.

After investigating different methods of repairing the canopy seal weld, the licensee decided to use a canopy seal clamp assembly (CSCA) developed by Combustion Engineering. The mechanical CSCA required no welding. The CSCA uses a 4-piece clamp set, socket head cap screw tensioning studs, and a grafoil gasket. The gasket is held in place by a two-piece Stainless Steel 304, split retainer that is positioned by a lower housing. Tensioning studs connect the lower housing to a flange, which rests on the head adapter plug of the spare CRDM, providing the compression force to stop the leakage. Vendor personnel installed the CSCA and provided QC activities during the CSCA installation. QC verification was provided for every step. The licensee performed a visual inspection of the socket head cap screws to ensure there were no burrs or galling. The inspector identified no problems during the review of the work package and the engineering disposition supporting the CSCA installation.

The final CSCA installation for the spare CRDMs used 15 socket head cap screws instead of 16 as originally specified. The licensee verified that the vendor calculations demonstrated that sufficient margin existed with only 15 socket head cap screws installed. Up to five nonadjacent cap screws could be removed without exceeding the allowable bolt stress. The licensee will conduct a visual examination to look for leakage after achieving normal operating pressure and temperature.

To install the CSCAs the licensee removed two CRDM stacks and disconnected leads for eight CRDMs in order to gain access for the repair. The licensee implemented a postmaintenance test to ensure the control rods functioned properly. The test withdrew the affected control rods to verify proper position indication. Additionally, the rods were cycled after they were withdrawn to ensure proper operation of the stationary and movable gripper coils. For the two CRDM coil stacks that were removed, the licensee will conduct rod-drop testing.

7.3 Installation of Encapsulation on Pressurizer Spray Valve

On February 11, 1992, the licensee determined that Pressurizer Spray Valve BB PCV455C had a body-to-bonnet leak. The leakage was from the gasket area between the body and the packing box. The licensee attempted to stop the leak by tightening the bonnet bolts to 275-280 foot-pounds (ft-lbs). The inspector determined that the licensee contacted and received approval from the valve vendor to increase the bolt torque from 220 ft-lbs to 280 ft-lbs prior to tightening the bolts to the maximum allowable bolt torque.

After leakage continued, NPE performed an evaluation to build and install an ASME Class 1E encapsulation for the pressurizer spray valve. The encapsulation was designed to withstand RCS design pressure; however, the repair was not to the pressure boundary since the spray valve fulfilled that purpose. The licensee determined that the leakage was not from a pressure boundary flaw; consequently, Generic Letter 90-05, "Guidance for Performing Temporary Noncode Repair of ASME Code Class 1, 2, and 3 Piping," was not applicable.

Westinghouse performed an analysis of the impact of the modification on the operability of the RCS while operating in Mode 1. The encapsulation weighed approximately 35 pounds and was welded to the 4-inch valve. The material of the encapsulation was compatible with the valve body and packing box. The vendor's engineering analysis determined that no adverse effects would occur on the valve, piping, or pipe supports as a result of the modification. The licensee determined all stress levels on the valve and piping were below allowable code values, and the effects of thermal stratification were within design requirements.

The inspectors reviewed the plans for the encapsulation and the weld procedures. The longitudinal welds on the encapsulation redirected the steam leak away from the portion of the encapsulation that was capable of being vented and directed the leak toward the final circumferential weld of the encapsulation to the valve body. The licensee identified a defect on the final circumferential weld and performed a weld repair. The penetrant test (PT) performed following the weld repair was accomplished using an improper QC examination procedure. The licensee determined, during the postinstallation reviews that the examination was conducted at 127°F with a procedure qualified to 125°F. A PIR was written and the PT was reperformed. The initial examination was accurate for temperatures up to 150°F; however, the licensee had not changed their procedure to allow examinations up to this temperature.

The inspectors observed the QC inspector perform the PT using the proper procedure. The inspectors identified no problems. Continuous health physics coverage was provided as specified by the radiation work permit. The licensee plans to remove the encapsulation and rework the valve during Refuel VI.

7.4 Inspection and Repair of NN11

Failure of the NN11 inverter synchronization card was caused by simultaneous firing of the silicon controlled rectifiers that resulted in a larger current draw from NK11 power supply than could pass. The inspector observed the troubleshooting efforts for NN11 performed under WR 01140-92. Initial troubleshooting efforts did not locate the source of the problem. The licensee decided to replace the supply fuses and reenergize the panel. The supply fuses failed again. After further review, the synchronization card was removed, tested, and found to be unsatisfactory. The card was replaced. Further inspection of the defective card revealed that some soldered connections on a terminal strip were cracked. The licensee repaired the solder connections and reinstalled the card.

On the basis of the preliminary results of HFAR RE-92-001, a decision was made by WCGS management to inspect the gating and synchronization cards in the remaining inverters. The spare inverter card was inspected and cracks were found in the soldered connection at the terminal strip. The licensee determined that the connector at the terminal strip was not flush with the card and that this physical arrangement stresses the solder connections. The other inverters were inspected and found to have similar cracking at the solder connections for the terminal strips. The licensee repaired the solder connections on all the inverter sychronization cards.

7.5 Material Evaluation Not Completed Prior to Installation

A pressure regulator installed under WR 00834-92 for the hydrogen analyzer, SGS02A, was found to have a material deficiency issued against it. A QA supplier audit, performed at the vendor in August 1990, determined that material testing prior to the regulator being used in the plant was required. Material testing was not performed prior to release for installation because a hold tag was not placed on the component while it was in the warehouse. The licensee initiated a PIR for this issue. The licensee determined the root cause was personnel error. An individual in WCGS supplier quality generated the wrong release form, which prevented the hold tag from being generated and the required testing implemented. The corrective actions required placing the controlling procedure in the required reading list and generating a nonconformance report against other pressure regulators in the warehouse.

NPE conducted an evaluation to determine if the installed pressure regulator affected the operability of Hydrogen Analyzer SGS02A. On the basis of additional material testing performed on February 12, 1992, NPE determined that the component did not affect operability. This appeared to be an isolated problem.

Conclusions

The licensee personnel who capped the thermocouple conduit performed the maintenance well. The operations organization received appropriate support from engineering. Engineering provided good dispositions for the pressurizer spray valve work activities, canopy seal thermocouple, and encapsulation. The licensee's review of the inverter and failure was thorough. An improper QC examination procedure was used; however, the licensee identified the condition and took appropriate action. The supplier/quality group onsite implemented effective corrective actions for a self-identified deficiency, which appeared to be an isolated problem.

8. ESF System Walkdown (71710)

The inspector conducted an independent verification of the SI system status. The inspector verified that valves and electrical circuit breakers were in the required position, power was available, and valves were locked where required. The inspector also inspected system components for damage or other conditions that could degrade system performance.

The inspector compared the valve lineup sheets from Procedure CKL EM-120, Revision 7, "Safety Injection System Lineup Checklists," to Piping and Instrumentation Diagrams M-12EM01 (Q), Revision 1, "High Pressure Coolant Injection System," and M-12EM02 (Q), Revision 2, "High Pressure Coolant Injection System." Subsequently, the inspector walked down accessible portions of the SI system using the valve checklist.

The inspector identified one discrepancy. CKL EM-120, Checklist B, pages 1-7, contains the breaker and switch lineup requirements. The status of the breakers was given as either "open" or "closed" or as "on" or "off." The inspector checked 36 breaker positions and, of these, 24 had terminology different than that listed on the checklist. If the checklist required a status of "open" or "closed," the actual positions on the breaker would be either "on" or "off."

With a required breaker position description different than that on the breaker, the equipment operator was compelled to interpret the necessary information. During an NRC inspection conducted June 1-30, 1989 (NRC Inspection Report 50-482/89-16, Section 7.a), an identical finding was discovered on the control building heating, ventilation, and air conditioning system. Section 7.a noted that, during the review of CKL GK-131, Revision 9, "Control Building HVAC Electrical Checklist," the terminology for verifying breaker positions was different than other CKLs. Some CKLs use "closed" or "opened" and some use 'on' or 'off.' The licensee's corrective action was to correct the terminology difference during 2-year procedure reviews and updates. The licensee completed a 2-year review of CKL EM-120, Revision 1, on January 2, 1991; however, the procedure was not appropriately updated. This is indicative of continuing weaknesses associated with the procedure revision process and will be tracked by an unresolved item (482/9202-03).

The inspector had the following additional observations:

° Nomenclature used in the CKL EM-120 description column to identify the valve, breaker, or handswitch that is to be positioned did not exactly match the nomenclature used on the equipment. One example of this was that in Checklist B, page 1 of 7, Component 52NG01BGR3 was described as "SI Pump A Discharge Hot Leg Isolation Valve EM 8802A" when it was actually labeled as "EM HV8802A Safety Injection Pumps To Hot Legs MOV." When operators manipulate a handswitch, it is important that the checklist nomenclature match the component designator. This helps to ensure that the proper component is operated.

° EM Pump B Casing Vent Valves EM-V208 and -V209 and EM Pump A Casing Vent Valves EM-V206 and -V207 were listed in the checklist as being closed with a flange. PMR 01206 dated December 8, 1989, revised the flange connection to add spool pieces and a pipe cap; however, the checklist was not revised to reflect the field configuration.

Conclusions

The SI system was determined to be aligned in accordance with station operating procedures; however, the failure to properly perform an adequate 2-year procedure review was identified as an unresolved item.

9. 10 CFR Part 50.59 Evaluation

The inspector reviewed several aspects of the licensee's programs related to safety evaluations performed in accordance with 10 CFR Part 50.59. During the inspection, the inspectors reviewed the procedures and controls, interviewed personnel, and reviewed completed safety evaluations and screening evaluations.

The licensee's procedures associated with 10 CFR Part 50.59 safety evaluations had undergone several revisions, with the latest revision issued during the inspection period. Generally, the procedure changes resulted in improved evaluations and better coordination of the 10 CFR Part 50.59 safety evaluations with the other parts of the plant modification and procedure change processes. The latest revision of the corporate procedure related to 10 CFR Part 50.59 resulted in the various licensee organizations utilizing the same guidance, which should increase the consistency of the safety evaluations performed.

Employee training on performing 10 CFR Part 50.59 safety evaluations consisted primarily of seminars provided by contract personnel several years ago. The licensee supplemented the seminars by various in-house discussions and self-study programs. Although a formal 10 CFR Part 50.59 evaluator/reviewer qualification program was not implemented, the inspectors noted that various organizations involved in performing safety evaluations accomplished a similar result by the use of supervisor's task assignments. The training department had developed and provided some training regarding the use of screening criteria for 10 CFR Part 50.59 applicability and was planning to develop a course for proper performance of safety evaluations. A rigorous training program would ensure that information related to future guidance, industry experiences, and lessons learned by various licensee personnel is distributed to all those involved in 10 CFR Part 50.59 related activities.

The inspector determined from the review of safety evaluations performed for plant modifications and procedure changes that the level of detail sufficiently addressed unresolved safety question concerns. The level of detail and the degree that was addressed varied among individuals and organizations. Additionally, as the program changed, the level of detail in the safety evaluations increased. The safety evaluations generated for PMRs implemented during the recent outage were more detailed than those that were performed several years ago.

The screening process for applicability of 10 CFR Part 50.59 was reviewed. The inspector identified no specific safety concerns related to modifications or procedure changes screened by the licensee. A concern was identified, however, for the screening evaluation performed for CWR-06586-91 that involved an engineering disposition to justify ESW flow rates during normal conditions that were lower than those provided in the USAR. The evaluation was screened from a 10 CFR Part 50.59 review since the lower flow rates were not considered to be a permanent condition and would not result in a change to the facility as described in the USAR. The inspector noted that a temporary reduction in ESW flow rates is not a basis for not performing a safety evaluation. The inspector, therefore, considered this to be a weakness in the licensee's 10 CFR part 50.59 program. However, since the reduction of ESW flow rates did not result in a change to the facility, the licensee's actions were acceptable.

Conclusion

The licensee maintained a good 10 CFR Part 50.59 program. The licensee was working to improve the consistency of evaluations among plant organizations. Formal training exists for use of screening criteria; however, the training department was beginning to consider a lesson on proper performance of safety evaluations. The inspector found no instances of inadequate 10 CFR part 50.59 screening; however, in one instance, the inspector noted that part of the basis for not performing a safety evaluation was not provided for by 10 CFR Part 50.59.

10. EXIT MEETING

The inspectors met with licensee personnel (denoted in Section 1) on March 9, 1992. The inspectors summarized the scope and findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT

Acronym List

AC	alternating current
ADM	administrative procedure
ASME	American Society of Mechanical Engineers
ARV	atmospheric relief valve
CCP	centrifugal charging pump
CKL	checklist
CRDM	control rod drive mechanism
CSCA	canopy seal clamp assembly
CVCS	chemical and volume control system
CRVIS	control room ventilation isolation signal
DEI	dose equivalent iodine
DG	diesel generator
DRPI	digital rod position indication
ESF	engineered safety features
ESW	essential service water
gpm	gallon per minute
HFAR	hardware analysis report
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control
IFI	inspection followup item
ITIP	Industry Technical Information Program
LER	licensee event report
LPM	loose parts monitor
mrem	millirem
NPE	nuclear plant engineering
NRC	Nuclear Regulatory Commission
OBE	operating basis earthquake
OFN	offnormal
PDP	positive displacement pump
PIR	performance improvement request
PMR	plant modification request
ppm	parts per million
psi	pound per square inch
psig	pounds per square inch gage
PSRC	Plant Safety Review Committee
PT	penetrant test
QA	quality assurance
QC	quality control
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RWST	refueling water storage tank
SG	steam generator
SI	safety injection
STN	surveillance nontechnical specification
STS	surveillance technical specification
TS	Technical Specification
UHS	ultimate heat sink
USAR	Updated Safety Analysis Report
WCGS	Wolf Creek Generating Station
WCNOC	Wolf Creek Nuclear Operating Corporation
WR	work request