U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-295/94006(DRP); 50-304/94006(DRP)

Docket Nos. 50-295; 50-304 License Nos. DPR-39; DPR-48

Licensee: Commonwealth Edison Company
Executive Towers West III
1400 Opus Place - Suite 300
Downers Grove, IL 60515

Facility Name: Zion Nuclear Power Station, Units 1 and 2

Inspection At: Zion, IL

Inspection Conducted: January 31 through February 11, 1994 and
February 11 through March 23, 1994

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3/29/94
Date

Inspection Summary

Inspection from January 31 to February 11 and from February 11 to March 23, 1994 (Report No. 50-295/304-94006(DRP))

Areas Inspected: This was a routine, resident inspection of licensee action on previous inspection findings; operations, plant support, maintenance and surveillance, engineering, and licensee event reports (LERs). Additionally, a routine maintenance inspection by regional inspectors occurred during this inspection period and is included in this report.

Results: One violation was identified during this inspection period. It concerned maintenance procedure inadequacies and is discussed in section 5a. Two unresolved items were identified: the first concerned a technical specification action requirement not being met and is discussed in section 3b; the second unresolved item concerned low flow of high head safety injection and is discussed in section 6a.

DETAILS

1. Management Summary

The inspectors met with licensee representatives (denoted in section 10) throughout the inspection period and at the conclusion of the inspections on February 11 (for the maintenance inspection) and March 23, 1994, to summarize the scope and findings of the inspection activities. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed during the inspection. The licensee did not identify any such documents or processes as proprietary.

Safety Assessment of Operations

The performance of operations during this inspection period was good overall, with the potentially significant exception of the failure to recognize a TS action statement. This will be reviewed further during a future inspection. Good performance was demonstrated throughout the long outage as illustrated by minimal out-of-service plant configuration errors, excellent performance of numerous surveillances, and error-free support for many special tests.

Safety Assessment of Plant Support

Improvements in the foreign material exclusion program have been seen, but problems still exist as demonstrated by a loose nut found in the diaphragm of an overhauled valve.

Containment housekeeping and material controls for Unit 2 closeout were weak; the resident inspectors identified housekeeping and material controls deficiencies after containment was considered ready for closeout.

Emergency Preparedness did an excellent job of the temporary relocation of the Technical Support Center and notification of personnel.

Safety Assessment of Maintenance

Maintenance activities were conducted in a professional manner by experienced and knowledgeable craftsmen. Individual craftsmen demonstrated proficiency with maintenance tools and equipment as well as knowledge of the assigned work. Familiarity with maintenance procedures was also evident and, in one case, an electrician continually looked ahead in the maintenance procedure to be cognizant of upcoming steps. This allowed the electrician to combine steps, reducing the number of breaker actuations needed during the performance of the inspection. However, two examples of inadequate maintenance procedures were identified, for which a Notice of Violation is being issued.

In general, maintenance personnel communicated well with other organizations. This was especially true with communications between instrument maintenance technicians and both operations and engineering personnel. However, communication problems appeared to exist between some electrical maintenance personnel and the assigned system engincers, as evidenced by discussions with both organizations during the review of both 4kV and 480V breaker issues.

Safety Assessment of Engineering

Engineering aggressively pursued the resolution of the many recurring Eagle 21 system problems with Westinghouse. Engineering support for the steam generator (SG) tube leak inspection and repair, and for review of previous eddy current data, were good. They also did an excellent job of keeping the NRC informed about SG issues during this period. Further review is required concerning discovery of low flow conditions for the high head safety injection system.

2. Licensee Actions on Previous Inspection Findings (92701, 92702)

   a. (Closed) Inspection Followup Item 50-295/304-90030-03: "Throttle Valve Position With Respect to Tests." The only remaining diagnostic evaluation team (DET) issue for this item involved service water flow balancing. This DET issue (2.3.06-03) is also being tracked under inspection followup item 29/304-90030-09. Therefore, 90030-03 is closed, with the issue being reviewed under 90030-09.

   b. (Closed) Inspection Followup Item 50-295/90030-07: "Licensee Response to MOV Program Deficiencies." This item addressed five concerns that the DET had regarding the licensee's response to identified motor operated valve (MOV) program deficiencies. The licensee completed actions on three of the concerns. The inspectors reviewed the licensee's actions for these concerns and found them to be acceptable. The fourth concern involved installation of limiter plates on various MOVs. The licensee considers this issue to be open because limiter plates still have to be installed on two non-safety-related MOVs. As all safety-related valves have been modified, and the two non-safety-related valves are scheduled, the inspectors concluded that this issue could be closed. The fifth concern involved diagnostic testing of MOVs in accordance with Generic Letter (GL) 89-10. The licensee's compliance with their GL 89-10 commitments is being separately inspected by the NRC (see Inspection Report 92030). Therefore, this issue is considered closed. As all five DET concerns are considered closed, the overall item is closed.

   c. (Open) Inspection Followup Item 50-295/90030-09: "Service Water System Design Issues." This item addressed a number of concerns regarding the capability of the service water (SW) and component cooling water systems to supply design basis cooling to various loads. DET issues remaining open on this item involve heat exchanger and room cooler inspections, installation of adequate flow instrumentation into various heat exchangers and room coolers, system flow balancing, and control of throttle valve positions. During the dual unit outage, the licensee performed heat exchanger inspections, installed flow instrumentation, balanced the SW system, and installed locks on various throttle valves to ensure the system remained balanced. However, the problems encountered with the locked valves during the 2B emergency diesel generator (EDG) run, as described in section 6a, indicated that this issue was not fully resolved. Therefore, this item will remain open.

d. <u>(Closed) Violation 295/93023-01</u>: "Inadequate Test Control on the 1C Containment Spray Pump." Corrective actions addressed the defining, documenting, and disseminating of design basis information. Upon reviewing the response to this violation, the inspectors determined that the identified corrective actions were basically identical to those the licensee committed to in responding to the escalated enforcement violations described in Inspection Report 295/304-93009. To avoid duplicate tracking, this violation will be closed, with corrective action followup being done under the escalated items. Additionally, the inspectors noted that, although not explicitly committed to, changes were made to the containment spray system periodic tests. These changes required recording of pump start times, as well as recording of vibration data. Finally, as described in section 4.a, the licensee performed extensive maintenance on the 1C containment spray pump. Therefore, this violation is closed.

No new violations or deviations were identified.

3. <u>Operations</u>

a. Operational Status

During this report period, Unit 2 began heatup following completion of its planned outage. However, due to the steam generator tube leak, discussed in section 6.a, the unit was returned to Mode 5 for generator inspection and repair. Unit 1 entered Mode 4 on March 20, and Mode 3 on March 22.

b. Activities

<u>Pressurizer Manway Leak</u>: On February 24, following filling of the Unit 2 pressurizer and increasing reactor coolant system to 360 psi, a leak was identified coming from the pressurizer manway. Removal of the manway revealed that the asbestos gasket had deteriorated due to age. The manway had not been removed since 1976 or earlier. The repair was completed within 5 days of identifying the leak. Good teamwork and contingency planning allowed the maintenance group to accomplish the task in a timely

manner. The Unit 1 pressurizer manway was opened earlier in the outage for inservice inspection and its gasket had been replaced.

Failure to Take Actions Required by Technical Specifications Within the Required Time Period: During the initial heatup of Unit 2, while the reactor was in Mode 3, the 2A auxiliary feedwater (AFW) pump was declared inoperable due to failure of its overspeed test. Shortly after the 2A AFW pump was declared inoperable, the 2C pump was also rendered technically inoperable, due to inoperability of its emergency power supply, emergency diesel generator (EDG) 2B. This put the unit in a 20-hour limiting condition for operation under technical specification (TS) 3.0.5. The licensee failed to recognize that they were in a 20-hour time clock until shortly after the clock had expired. The circumstances surrounding the failure to take action within the TS time requirements is an unresolved item pending further inspector review (304/94006-01(DRP)). A special inspection to examine this issue will be completed by April 30, 1994. Further discussion on the turbine-driven AFW pump problems and the EDG failure is provided in section 6.a.

c. Safety Assessment of Operations

The performance of operations during this inspection period was good overall, with the potentially significant exception of the failure to recognize a TS action statement. This will be reviewed further during a future inspection. Good performance was demonstrated throughout the long outage as illustrated by minimal out-of-service plant configuration errors, excellent performance of numerous surveillances, and error-free support for many special tests.

No violations, deviations or inspector followup items were identified. One unresolved item was identified.

4. Plant Support

a. Radiation Protection Controls

The inspectors verified that workers were following health physics procedures and randomly examined radiation protection instrumentation for operability and calibration. During this inspection period, concerns were raised by station workers regarding use of respirators in contaminated areas. This issue will be addressed in Inspection Report 94008.

During the repair of residual heat removal pump 1B, the inspectors noted good radiation protection controls were established, including building a ventilated tent around the room entrances for both the heat exchanger and the pump rooms.

b. Security

During the inspection period, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to their approved security plan.

c. Fire Protection, Foreign Material Exclusion, and Housekeeping

The inspectors monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign matter.

Foreign Material Exclusion Program: During periodic testing, valve 1AOV-RC8034C, loop "D" fill header valve, would not open when actuated from the main control board. Investigation revealed air leakage between the actuator and diaphragm seal area. This leak caused the air pressure to be too low to overcome the fail-close spring force. The actuator bolting was loosened and foreign material, a nut, was found to be causing the leak. The licensee could not confirm that the nut was a component of the valve, although the valve diaphragm was replaced during the outage. A root cause evaluation was initiated.

Containment Closeouts: Significant efforts were made by the licensee to prepare the Unit 2 containment for closeout. However, the inspectors identified a substantial area of loose paint in the containment. The peeling paint was of concern as a potential source for blocking the containment recirculation sump screens (See Information Notices 89-77 and 93-34). The loose paint, when removed, amounted to the volume of a 55 gallon drum. After the licensee determined that the containment was ready for closeout, the inspectors identified additional housekeeping and equipment concerns. The licensee was addressing the last of the concerns when the leak occurred on the steam generator.

The inspectors noted a significant improvement in housekeeping during the Unit 1 closeout inspection. Peeling paint had been removed and lighting was good. However, two hangers were not made up, a strut was leaking and required repair, resistance temperature detector cables for the reactor vessel instrumentation system were unsupported and swaying in the ventilation air flow (affording a potential for fatigue failure), and two reactor coolant pumps were dripping oil to the containment floor. These items will be corrected and verified.

d. Emergency Preparedness

Technical Support Center (TSC) Temporary Relocation: On March 5, a fire occurred in the TSC automatic bus transfer (ABT) switch. A bus voltage dip had occurred when reactor coolant pumps 2C and 2D were started, causing an ABT to switch to the backup power supply. The fire occurred in the ABT switch when it attempted to switch power from the backup to normal power supply. Station and corporate management designated the nearby emergency operating facility as the interim TSC, and proper notifications were made. The ABT switch was repaired on March 7, and the TSC was moved back onsite.

e. Safety Assessment of Plant Support

Improvements in the foreign material exclusion program have been seen, but problems still exist as demonstrated by a loose nut found in the diaphragm of an overhauled valve.

Containment housekeeping and material controls for Unit 2 closeout were weak; the resident inspectors identified housekeeping and material controls deficiencies after containment was considered ready for closeout.

Emergency Preparedness did an excellent job of the temporary relocation of the Technical Support Center and notification of personnel.

No violations or deviations were identified.

5. <u>Maintenance and Surveillance</u>

Station maintenance and surveillance activities were observed and reviewed to evaluate their effectiveness and to determine if these activities were properly coordinated and effectively controlled and implemented. This was accomplished by observations of work activities, discussions with maintenance, engineering and management personnel, and reviews of records, procedures, and associated documentation. Region based NRC personnel assisted the resident inspectors in the evaluation of maintenance activities during this reporting period.

a. Activities

<u>4kV Breaker Problems</u>: The inspectors reviewed the maintenance history for ITE 4kV HK series breakers which had exhibited failures, at other plants, due to hardening of grease in the breaker operating mechanisms. The problem was discussed with licensee maintenance personnel, who stated that all breakers of this type had been overhauled and the grease changed. This determination was based on a computer printout of completed work requests for the approximately 120 safety-related breakers in question. The inspectors reviewed the listing and noted that many of the nuclear work requests were for breaker <u>inspections</u>, not overhauls. Station Maintenance Procedure E000-8, "Circuit Breaker Inspection 4kV Type 5HK" was referenced. The inspectors reviewed the procedure and determined that it was not adequate to identify

and correct the hardened grease problem. The evaluation by licensee personnel failed to identify this and, therefore, did not verify that all breakers had been checked for the hardening grease problem.

The inspectors also reviewed procedure E02-1, "Circuit Breaker Overhaul 4kV Type 5 HK", and noted that completion of this procedure would adequately address the hardened grease problem. Further reviews, at the inspector's request, ultimately determined that all but two spare breakers had been overhauled for Unit 1. Based on the review of the Unit 1 records, the 4kV breaker overhaul records were considered acceptable for both units. Although overhauls were performed for all Unit 1 safety-related breakers in service, the records review indicated a weakness by the licensee in performing complete and adequate evaluations of maintenance problems.

480 V Breaker Maintenance: The inspector observed maintenance of 480 volt Westinghouse model DS-206 circuit breakers. During the maintenance, the inspector noted that the procedure being used, E000-3 "Inspection, Maintenance and Testing of Westinghouse 480 Volt Switchgear Breakers," did not contain all the measurements and tolerances specified in Vendor Manual W120-0143 (Westinghouse Instructional Bulletin I.B.33-790, "Instructions for Low-Voltage Power Circuit Breaker Types DS and DSL.")

The procedure required measuring contact material thickness for main and arcing contacts and moving and fixed contacts for each phase. The vendor technical manual stated, "if the tips are burned or worn more than 0.030", the contacts must be replaced." Procedure E000-3 allowed a wear of 0.062 inches for the contacts, more than twice the tolerance specified by the vendor manual.

The procedure deficiencies were discussed with licensee personnel, who agreed that the procedure was inadequate. The above examples of not following vendor specified measurements and tolerances for breaker inspection and maintenance constitutes an inadequate procedure. This is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (295-304/94006-02a(DRS)).

Procedure E000-3 required thickness measurements for main and arcing, moving and fixed contacts (one pair of each) for each phase (four pairs per phase). The "as left" measurements were required to be recorded in the procedure, however, only one space was provided for each main, fixed and moving, contact pair. This seemed to imply to the electrician that only one contact of each pair needed to be measured. The same problem was true for measuring the gaps between the fixed contact cage and the two fixed arcing contact arms. Although there were two gaps per phase there was only one blank for "as found" and "as left" measurements in the procedure. A review of the vendor technical manual and a supplemental technical bulletin both indicated that both gaps were to be measured.

Additionally, while measuring the gaps between the stationary contact cage and the stationary fixed contacts, one gap was found to be 0.074 inch, exceeding the specified 0.070 inch tolerance. The procedure stated that if the gap was out of tolerance "to adjust/replace contacts." The breaker contained no provisions for adjustment. The electrician used a 12-inch adjustable wrench and bent the contact back within tolerance. The procedure did not mention bending the contact as an approved method of adjusting the gap. The vendor technical manual and the supplemental technical bulletin specified replacement of the contacts if they were found out of tolerance.

During the review of the vendor manual for the 480 volt breakers, the inspector noted that the manual specified that breakers be overhauled after 500 breaker operations. This was not considered in the determination of the time between breaker overhauls. The justification used to determine the overhaul frequency was that the current frequency for all 480V breakers feeding motors was "OK" since no wear-related failures of these breakers had occurred. This method of establishing maintenance frequencies was discussed with the licensee maintenance staff. Licensee personnel agreed that more thorough evaluations were needed, especially when safety-related equipment was involved.

<u>Containment Spray Diesel Maintenance</u>: The inspectors observed in-process maintenance activities on the containment spray diesel engine. The 18-month and the 5-year preventive maintenance (PM) tasks, performed on the diesel, indicated possible internal engine problems. Upon investigating, the licensee discovered an oil leak from a head gasket. As replacement of the exhaust manifold was already part of the periodic maintenance, the licensee decided to open the leaking head and replace the gasket. When the head was opened, all three cylinders and pistons were found to be badly pitted. The licensee then opened the other three heads and found those cylinders and pistons pitted also. It was conservatively decided to inspect the heads on the Unit 2 diesel-driven pump. Pitting was found on Unit 2 cylinders and pistons; however, it was not as extensive as on Unit 1. The licensee replaced all the cylinders and pistons in both pumps. The inspectors witnessed portions of the maintenance work on both pumps, including replacement of the pitted parts. The licensee's actions regarding the head gasket leak and the pitting problem were considered conservative and proactive.

The inspectors reviewed the work instructions included in the work package for overhaul of the diesel and found the instructions to be incomplete and inadequate. For example, the instructions for reassembly of the engine did not include the torquing pattern or torquing sequence for bolts securing the cylinder head and other engine components as specified in the vendor manual. Three torquing passes were required by the instructions, rather than the four passes specified in the vendor manual. The instructions were subsequently revised to include these additional details.

Section 21 of Appendix C of procedure ZAP 400-02, "Initiating and Processing a Work Request", Revision 3, required that work instructions be in sufficient detail for a qualified workman to accomplish the work. The required details were not provided in the work package for the containment spray diesel, especially in the area of torquing. The failure to provide adequate work instructions as required by ZAP 400-02 is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (295/304-94006-02b(DRS)).

There was a history of starting problems on the 1C CS pump involving initial start-attempt failures followed by successful start and run. Therefore, various exploratory tests were done on both units. Although the Unit 2 pump appeared to have air bubbles and entrained gases in the fuel line, similar to those observed on Unit 1, no starting problems occurred on Unit 2. As part of the routine 5-year maintenance, the 1C CS pumps's fuel pump was replaced. When the old fuel pump was disassembled for refurbishment, extensive degradation of the pump seals was noted. The licensee theorized that, when the 1C CS pump sat idle, the fuel pump seals gradually dried out and allowed air to seep in. Once the 1C CS pump finally started, the fuel wetted the seals, preventing further air inleakage. This explained why the 1C CS pump failures were not repeatable. The licensee planned to continue testing on an increased frequency until they successfully demonstrated that the 1C CS pump starting problems have been resolved. The inspectors had no problems with the licensee's actions or planned approach.

Review of Nuclear Work Requests (NWRs): A sample of closed NWRs was reviewed for technical adequacy and appropriate action. Approximately forty percent of the NWRs reviewed were canceled. A further review of the canceled NWRs indicated that the cancellations appeared to be done for acceptable reasons, mostly duplication of work. One case was noted where there was no evidence that the equipment problem documented on the canceled NWR had been corrected. NWR Z-27840 was written on December 19, 1992, to correct a fuel oil filter inlet piping leak on the 2A EDG. The NWR was canceled on December 20, 1992. A note in the package stated "Leakage is oil coming from the west side of the cam cover. The fuel oil filter is not the source of the leakage. This W/R can be canceled." No records could be found indicating that the actual leak source was ever repaired; however, substantial work was performed on this EDG during the dual unit outage and no evidence of leakage in this area was found during the inspection.

Reasons for some of the NWR cancellations could not be easily determined, because the reasons were not written in block 50 of the NWR form as specified by procedure ZAP 400-02, "Initiating and Processing a Work Request", Revision 3, Appendix AL, Section 2.b. Licensee personnel stated that they were aware that a large number of NWRs were being canceled and, in order to reduce the number of cancellations, a more careful screening of NWRs was now being performed prior to assigning an NWR number. In addition, the new electronic work control system, scheduled to be implemented at Zion in the near future, would allow a more through review for NWR duplications and further reduce the need for cancellations.

Emergency Diesel Generator 1A: During performance of bus drop tests which included automatic starting of the 1A EDG, an equipment operator thought he heard an unusual knocking noise and tripped the EDG. The EDG was declared inoperable and extensive investigations were conducted without identifying any cause for the unusual EDG noise. Although the 1A EDG had the new monitoring and control system installed, the computer which stored the EDG historical data had tripped, depriving the licensee of analysis data. The engine was successfully run and performance tested and the 1A EDG was declared operable.

Residual Heat Removal Pump 1B: During periodic testing of the 1B residual heat removal pump, high vibration levels were measured when flow was between 2500 and 3075 gpm. Upon tearing down the pump, the licensee discovered that a lock washer was missing from the impeller holddown bolt. The bolt was slightly loose, which caused the higher vibrations. The impeller was replaced in 1991, and the washer was evidently not reinstalled. Following installation of the washer and tightening of the bolt, the pump was returned to service. Vibration levels returned to normal. The inspector verified that the current procedure includes specific instructions for installing the lock washer.

Oil Circuit Breaker (OCB) Testing: On March 9, 1994, while the Operational Analysis Department (OAD) and the Northern Division load dispatcher were performing breaker direct transfer trip circuit testing in Zion's switchyard, OCB 34 and OCB 45 were unintentionally tripped. The trip of these OCBs occurred because the special order card was hung on the "Transmit" switch and the test switches tripped instead of on the "Receive" switch. No equipment was lost when these OCBs opened. An investigation into the cause of the wrong test switches being tripped revealed the root cause was improper verbal communications between the Northern Division (ND) load dispatcher and the station. The tape of the conversation revealed the ND load dispatcher correctly identified the "Receive" test switch was to be tripped and the station repeated back that the "Transmit" test switch was to be tripped.

The ND load dispatcher did not challenge the repeat back, and the wrong switch was tripped. The station is counseling the involved operators and revising the applicable Zion Administrative Procedure (ZAP).

b. Safety Assessment of Maintenance and Surveillance

Maintenance activities were conducted in a professional manner by experienced and knowledgeable craftsmen. Individual craftsmen demonstrated proficiency with maintenance tools and equipment as well as knowledge of the assigned work. Familiarity with maintenance procedures was also evident and, in one case, an electrician continually looked ahead in the maintenance procedure to be cognizant of upcoming steps. This allowed the electrician to combine steps, reducing the number of breaker actuations needed during the performance of the inspection. However, two examples of inadequate maintenance procedures were identified.

In general, maintenance personnel communicated well with other organizations. This was especially true with communications between instrument maintenance technicians and both operations and engineering personnel. However, communication problems appeared to exist between some electrical maintenance personnel and the assigned system engineers, as evidenced by discussions with both organizations during the review of both 4kV and 480V breaker issues.

One violation with two examples was identified.

6. <u>Engineering</u>

The inspectors evaluated the extent to which engineering principles and evaluations were integrated into daily plant activities. This was accomplished by assessing the technical staff involvement in non-routine events, outage-related activities, and assigned technical specification surveillances; observing on-going maintenance work and troubleshooting; and reviewing deviation investigations and root cause determinations.

a. Activities

<u>Eagle 21 Corrective Actions</u>: Prior to the dual unit outage, the Eagle 21 process protection system experienced several recurring problems. The licensee identified the root causes for the problems and took corrective actions to prevent recurrence.

The failures of the power distribution panels were attributed to a capacitor failure. The capacitor was part of a resistor/capacitor timing circuit which included a capacitor, a resistor, and a relay sealed together as a single component. The capacitor failed due to heat generated by the 3-watt resistor. The assembly was reconfigured so that the resistor was mounted outside of the sealed component.

The failures of the 15 volt power supplies were attributed to a bad lot of capacitors. The capacitors leaked and finally failed after some period of time in service. All power supplies with the suspect capacitors had the capacitors replaced.

Sporadic alarms were experienced on both units due to communication problems between Eagle 21 subsystems. The root cause was attributed to a data tearing problem which was detected by the test sequence processor (TSP) and resulted in the alarm. The TSP software was revised to correct the alarm. The revision did not change the actual protection programming for the system.

The TSP software was also revised to provide error code logging within the TSP buffer. The data could then be recovered for trouble shooting efforts. During the licensee 10 CFR 50.59 review concerning the TSP software, the licensee identified a subtle problem that could have eliminated necessary alarms. The problem was promptly resolved and the corrected software was obtained. The identification of a potential problem before accepting the new software was a positive accomplishment by the engineering group.

<u>Moisture Separator Reheater (MSR) Repairs</u>: During the installation of turning vane bracing in the Unit 2 cross-under piping, the licensee identified wall thinning due to erosion on the MSRs. The thinning occurred at the point where the hemispherical head meets the shell. Both units were inspected for similar thinning and areas requiring repair received weld overlays to return the metal to acceptable thickness.

While the 1C West MSR was being repaired, a crack developed. The licensee determined the crack was due to a stress riser caused by an existing notch adjacent to a drain hole, coupled with the high welding temperatures. The crack extended for approximately 6 inches in opposite directions from the drain hole. Following one unsuccessful attempt to repair the crack, the crack was repaired and the wall thinning was corrected. The other MSRs for both units were reinspected for the pre-existing notch and any notches identified were removed.

<u>Steam Generator Tube Leak</u>: On March 8, 1994, at 11:45 a.m., with Unit 2 in mode 3 at approximately 2235 psig and 547°F, the chemistry department notified the control room that preliminary sample results indicated a primary to secondary leak in the 2D steam generator. The operating crew entered abnormal operations procedure AOP-1.2 "Steam Generator Tube Leak" at 11:56 a.m., pending leak rate confirmation by the chemistry department. At 12:35 p.m., chemistry confirmed the leak rate to be approximately 1.13 gpm, which placed Unit 2 in a 36-hour limiting condition for operation to cold shutdown. The unit was returned to cold shutdown, the reactor coolant loop isolation valves were closed, the loop was drained, and the SG manway was opened. The faulted tube, readily identified by its leak, was in Row 17, column 56 and

had an approximate two-inch longitudinal crack just inside the upper tube sheet. The previous bobbin coil eddy current data was reviewed for this tube and showed a very small indication in the area. Five tubes with greater indications and in the same general area as the failed tube were previously plugged.

Eddy current tests of 1628 tubes were performed using the bobbin coil method and ten tubes (including the faulted tube) were identified which required plugging. One hundred percent of the 2D SG tubes were tested, from one inch above to three inches below the top of the tube sheet, using a motorized rotating pancake coil (MRPC). All ten of the bobbin coil indications were confirmed, and two other indications were detected, by the MRPC. A review of 1992 bobbin coil data identified that 6 of these 12 tubes had previous visible indications. The 12 tubes plugged (including the faulted tube) did not meet the TS one-percent failure rate which would have required inspection of the other SGs.

To determine if similar tube failures were evident in the other generators, the licensee began MRPC inspection of 407 tubes in the upper tube sheet area of the 2B SG and no indications were found. In addition, the 1992 bobbin coil data for the same general tube locations that were suspect in the 2D SG was reviewed for SGs 2A and 2C. The review was to look for indications using the knowledge gained from the examination of the bobbin coil data from SG 2D. No other indications were identified during the review. More detail on the eddy current testing results is provided in inspection report 93022.

Main Steam Safety Valve Testing: On March 11, the licensee was informed of a potential problem with the online pressure-assist main steam safety valve (MSSV) setpoint testing method used by the licensee. It appeared that the calculation used to determine the valve's setpoints was not conservative for all valves, and could result in the valves being left at a higher setpoint than allowed by the technical specifications. The licensee indicated that all 20 of the MSSVs on each unit were removed from the system during the last refueling outage and returned to the valve manufacturer for refurbishment. The valve setpoints were properly established prior to the valves being returned to the site. At the beginning of the current Unit 1 refueling outage, the MSSVs were tested using the pressure-assist method under question. Three valves were found to be below the allowable setpoint and were set higher, while the remaining 17 valves were not adjusted. None of the Unit 2 valves were tested during the current planned outage. The licensee performed an operability determination on the three valves which were adjusted, and determined that the valves were operable. This determination was based on the MSSVs at Zion being physically different than the valves with the potential problem. (The valves with the potential problem apparently have a lip area on the seat, while the Zion MSSVs do not.) The inspectors discussed the conclusions of the operability determination with the licensee. No problems were identified.

Turbine-Driven Auxiliary Feedwater Pump Trip: On March 8, during testing of the 2A turbine-driven AFW pump, the pump tripped on overspeed. Throughout the last operating cycle, overspeed trips occurred frequently during testing of the 2A pump. In order to resolve this problem, all the steam traps were replaced during the dual unit outage. The licensee speculated that water had accumulated in the steam line following the AFW hydrostatic test. Additionally, it appeared that one of the new steam traps was not working properly. Further root cause investigation was hampered by the unit returning to cold shutdown because of the 2D steam generator tube leakage; this eliminated the steam source for running the pump. Because of the recurrent nature of the overspeed trips on the 2A pump, this issue will be tracked as an inspection followup item (304/94006-03(DRP)). This item will be closed by May 31, 1994.

Component Cooling Water (CCW) Heat Exchanger Noise: Towards the beginning of the inspection period, the inspectors identified an unusual noise from the SW outlet end of the #2 CCW heat exchanger. The noise was confirmed by the licensee through acoustic testing. The licensee determined the noise to be non-metallic in nature and described it as being similar to a "large wooden mallet." However, towards the end of the inspection period, the inspectors noticed that the noise in the #2 heat exchanger was getting more severe and that noise was also heard in the SW outlet end of the #0 CCW heat exchanger. The licensee confirmed the inspectors' observations and committed to redoing the acoustic monitoring. The licensee theorized that the noise might be attributable to changes in SW flow rates; however, they had not done enough research to confirm this conjecture. The system engineers did not believe that the noise came from loose plugs, because they felt that the plugs would have been swept through the SW system rather than remaining in the heat exchanger. This issue will be tracked as an inspection followup item (295/304-94006-04(DRP)), pending review of the acoustic monitoring results and SW flow data. This item will be closed by May 31, 1994.

Zebra Mussels in Diesel Generator Coolers

On March 7, during a performance test on the 2B EDG, the jacket water temperature exceeded its normal operating temperature of 180°F. At this point, operations personnel unlocked and further opened the jacket water cooler SW outlet valve to allow completion of the EDG run. The SW outlet valves for the lube oil cooler, jacket water cooler and both intercoolers had been set to allow the SW design basis flow through the generators. The jacket water cooler outlet valve was repositioned and the SW flow rates were measured for jacket water and lube oil coolers and verified to be greater than the minimum design flow rates.

The 2B EDG jacket water cooler and lube oil coolers were opened, inspected and cleaned. The jacket water cooler was heavily fouled with a mat of zebra mussel shells and corrosion nodules approximately one-half inch thick against the inlet tube sheet. The lube oil cooler had approximately 50 percent of its tubes plugged with a combination of zebra mussel shells and corrosion nodules. Based on these results, both intercoolers were opened, inspected and cleaned. The results of this inspection revealed plugging of approximately 50 percent of one cooler and 100 percent of the other.

The 2A EDG jacket water cooler and both intercoolers were opened, inspected, and cleaned on March 9, 1994. The jacket water cooler had approximately 12 percent tube blockage with zebra mussel shells and corrosion nodules. The lube oil cooler had approximately 50 percent partial tube blockage with mussel shells and corrosion nodules. The "0" EDG jacket water, lube oil cooler, and the 0-2 intercooler were opened, inspected and cleaned on March 12, 1994. The jacket water cooler had approximately six percent partial blockage with mostly corrosion nodules. The lube oil cooler had approximately 12 percent partial blockage with corrosion nodules. The 0-2 intercooler had one tube partially blocked. Based on the cleanliness of the 0-2 intercooler, an inspection of the 0-1 intercooler was not performed. The 1B EDG lube oil and jacket water cooler was previously opened, inspected and cleaned on February 14, 1994. None of the coolers had any tubes blocked. The 1A EDG coolers were not opened since the EDG was not supplied by the fire protection (FP) header at any time during the outage. The fire protection header was considered the source of the mussels, as described below.

Most of the zebra mussel shells and corrosion nodules found in the 2B EDG heat exchanger were too large to pass through the service water strainers. The fact that some shells had both halves connected indicated that the shells did not enter the SW or FP system through the SW or FP pumps, which would broken the shells into pieces.

It was concluded that, when the chlorination system was started, zebra mussels already in the FP system were killed by ingesting chlorinated water. In November of 1992, the 10-inch header was flushed into the forebay. This flush apparently caused some of the exterminated zebra mussels and corrosion nodule debris in the 10-inch header to fall into the 4-inch headers supplying the backup water to each individual EDG. The piping configuration to the EDGs were different lengths which caused some EDGs to have more zebra mussels than others. The licensee has closely followed zebra mussel infestation.

High Head Safety Injection Low Flow: During a technical staff surveillance (TSS) 15.6.84 on February 28, 1994, the high head safety injection system flow rate was determined to be below the requirements of TS 4.3.4.C.1. The TS required that the sum of the three lowest flow rates of the four injection lines be equal to or greater than 275 gpm. The as-found summed values for charging pump A was 255.6 gpm and for charging pump B was 249 gpm.

The flows were last set in June of 1992 during the Z1R12 refueling outage. The unit resumed power generation on August 13, 1992. The flows were required to be reset in 1992 following a modification to remove the boron injection tank and associated valves. No other manipulation of the injection line throttle valves were made prior to the February 28 surveillance.

The station determined that the throttle valve positions were compromised by the installation of the valve restraints prior to the August 1992 restart. The restraints protect against inadvertent changing of valve position and consist of a locking nut and retaining plate assembly. The licensee postulated that the installation of the retaining plates over the locking nuts resulted in the stems for one or more valves being forced further toward the seats. The stem movement would cause the gaps between the discs and the seats to be reduced. Radiographs of the valves indicated that the distance between the disc and the seat ranged from 1/8 inch to 1/4 inch. Therefore, small changes in the gap would have a significant effect on flow.

The installation of the lock nut and the retaining plate was left to the skill of the craft. No additional verification of injection flows were performed following the installation of the valve restraints in 1992. However, paint marks across the lock nuts and valve stem nuts remained intact, indicating the stems had not rotated since the lock nuts were installed.

Throttle valves for the low head safety injection flow paths were not affected, and no other examples of problems with throttle valves could be found. This issue requires further review by the inspectors for safety significance and is considered an unresolved item (295/94006-05(DRP)). This item will be included within the special inspection to be completed by April 30, 1994.

Motor-Operated Valve Interim Inspection: A regional interim inspection of the GL 89-10 program for MOVs was performed to determine the status of the work. The inspection disclosed that work was progressing satisfactorily in all areas and that there were no unforeseen scheduling problems. The licensee appeared to be dedicated to completing all scheduled testing within the committed period.

b. Safety Assessment of Engineering

Engineering aggressively pursued the resolution of the many recurring Eagle 21 system problems with Westinghouse. Engineering support for the steam generator (SG) tube leak inspection and repair, and for review of previous eddy current data, were good. They also did an excellent job of keeping the NRC informed about SG issues during this period. Further review is required concerning discovery of low flow conditions for the high head safety injection system.

No violations or deviations were identified. One unresolved item and two inspection followup items were identified.

7. <u>Licensee Event Reports (LERs) Followup (92700)</u>

Through direct observations, discussions with licensee personnel, and review of records, LERs were reviewed to determine that reportability requirements were fulfilled, immediate corrective actions were taken and actions to prevent recurrence were accomplished in accordance with technical specifications. The LERs listed below were reviewed during this report period and are considered closed:

LER 304-89002 "Unauthorized Open Knife Switch Controlling Load Shedding Relay 237 LSX." During a review of previous inspection reports for NRC concerns on LER commitments (see paragraph below), it was identified that closure of this LER was not previously documented in an inspection report. The inspectors noted that the licensee had committed to issuing a supplemental report addressing the results of their investigations. However, no supplemental report was ever issued, and the licensee has no open corrective actions for the LER. The LER is closed; however, the inspectors will track issuance of the supplemental report as inspection followup item 304/94006-06 (DRP). This item will be closed within the next routine inspection report period.

LER 295-90003 "Fire Door Found Open with No Firewatch Established." During a review of previous inspection reports for NRC concerns on LER commitments (see paragraph below), it was identified that closure of this LER was not previously documented in an inspection report. The inspectors confirmed that the licensee had completed all corrective actions. Additionally, the inspectors noted that changes in the fire protection program had significantly decreased the number of occurrences of fire doors being left open without firewatches being established. This LER is closed.

LER 304-93003 "Failure of Pressurizer Safety Valves to Meet "As-found" Acceptance Criteria": This LER documented the failure of three pressurizer safety valves on Unit 2 (two valves failed low and one failed high) and two pressurizer safety valves on Unit 1 (both failed low). The licensee determined that the four valves which failed low did so due to boron accumulation on the seat; however one of the Unit 2 valves also had debris on the seat which prevented it from lifting. No reason could be found for the one valve which initially lifted high. All the valves were disassembled, cleaned and reassembled. As-left testing, done with steam, verified that all setpoints were within technical specification requirements. This LER is closed.

In addition to the above LERs, the inspectors obtained and reviewed the statuses of open LER commitments dating from 1988 to 1991. While the inspectors did not identify any safety concerns with the open commitments, they found that a number of commitments appeared to be languishing, in that no work was being accomplished on the item and schedule extensions were obtained for vague or non-existent reasons. (Approximately eight percent of all the LERs issued between 1988 and 1991 still have open commitments.) Additionally, the inspectors noted cases where a modification or TS change was originally considered feasible but now cannot get technical review board or onsite review approvals. This included a change to remove specific radiation monitor numbers from the TS because the monitors no longer existed in the plant. The inspectors will continue to periodically review the status of LER commitments.

No violations or deviations were identified. One inspection followup item was identified.

8. Inspection Followup Items

Inspection followup items are matters which have been discussed with the licensee which will be reviewed further by the inspector and which involve some action on the part of the NRC or licensee or both. Three inspection followup item disclosed during this inspection are discussed in sections 6a and 7.

9. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance or deviations. Two unresolved items disclosed during this inspection are discussed in sections 3b and 6a.

10. Persons Contacted

R. Tuetken, Vice President, Zion Station
E. Broccolo, Station Manager
*M. Lohmann, Site Engineer & Construction Manager
*P. LeBlond, Executive Assistant
*S. Kaplan, Regulatory Assurance Supervisor
*D. Wozniak, Operations Manager
*R. Link, Technical Superintendent
*L. Simon, Maintenance Supervisor
J. LaFontaine, Outage Management Manger
*T. Printz, Assistant Superintendent of Operations
*R. Cascarano, Services Director
*W. Stone, Performance Improvement Director

*K. Hansing, Site Quality Verification Director
R. Chrzanowski, Technical Staff Supervisor
R. Milne, Security Administrator
P. Cantwell, Unit 2 Operating Engineer
W. T'Niemi, Unit 1 Operating Engineer
K. Moser, Unit 0 Operating Engineer
*K. Dickerson, Regulatory Assurance - NRC Coordinator

* Indicates persons present at the exit interview on March 23, 1994.

The inspectors also contacted other licen: e personnel including members of the operating, maintenance, security, and engineering staff.