APPENDIX C

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/94-31
50-529/94-31
50-530/94-31

Licenses: NPF-41
NPF-51
NPF-74

Licensee: Arizona Public Service Company
P.O. Box 53999
Phoenix, Arizona

Facility Name: Palo Verde Nuclear Generating Station, Units 1, 2, and 3

Inspection At: Maricopa County, Tonopah, AZ

Inspection Conducted: September 4 through October 15, 1994

Inspectors: K. Johnston, Senior Resident Inspector
H. Freeman, Resident Inspector
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J. Kramer, Resident Inspector

Approved: Edward J. Wong 11/29/94
H. Wong, Chief, Reactor Projects Branch F Date

Inspection Summary

Areas Inspected (Units 1, 2, and 3): Routine, announced inspection of plant status, onsite response to events, operational safety verification, maintenance and surveillance observations, operations and engineering followup, and licensee event report review.

Results (Units 1, 2, and 3):

Operations

While the conduct of operations was observed to be positive in some instances, there were some notable instances where poor operator performance resulted in events similar to problems experienced in the past year. In response to these and other events, the licensee implemented a higher standard for the conduct of operations and made several significant crew changes, demonstrating a heightened level of concern for the conduct of operations. In some less significant instances, operations management was not as responsive in addressing problems.

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- A Unit 2 dilution event was similar in several respects to a November 1993 Unit 1 reactor inventory control event in that an RO became distracted during a critical plant evolution. Licensee management performed a detailed and thorough evaluation of the event and took prompt and comprehensive action to address conduct of operations weaknesses (Section 4.3).

- Other conduct of operations weaknesses included a Unit 1 shift supervisor who did not recognize that he briefly had two auxiliary feedwater pumps concurrently inoperable (Section 2.4) and a Unit 2 control room supervisor who failed to implement TS actions after removing a startup nuclear instrument from service (Section 2.2).

- Strengths in the area of conduct of operations were noted during the review of simulator evaluation (Section 8). In addition, operator actions were well planned and controlled during restoration from a heater drain pump trip in Unit 1 (Section 4.2).

- Operations management's response to some issues, such as the operability of Unit 2 vital batteries (Section 4.1), and the setting of the remote shutdown panel (RSP) speed potentiometer for the "A" auxiliary feedwater pump, was prompt and thorough (Section 2.3).

- While operators appropriately involved operations management in addressing concerns during the Unit 2 drain to midloop, the concerns involved procedure and equipment weakness that complicated a critical plant evolution (Section 2.1).

Maintenance

The inspector noted several examples of good maintenance practices in the field, including the involvement of supervision and maintenance engineers. However, in the review of other work, it was again noted that some work instructions were weak and in one instance maintenance personnel did not follow instructions (Section 9.3). While an emphasis had been placed on material condition recently, the boric acid leakage identification program specified in GL 88-05 had not been fully implemented (Section 9.1).

Engineering

During this period, engineering demonstrated that when involved to address a significant plant problem impacting power production, they respond with aggressive, conservative, and comprehensive evaluations and actions (such as the issues regarding the Unit 2 safety-related batteries). However, as noted in the following three instances, when problems are identified that do not appear to have an immediate impact on plant operations or do not receive upper management attention, engineering evaluations are sometimes slow and poorly documented. Additionally, some corrective actions are slow to be implemented.

- Two Unit 2 vital battery cells were identified as potentially degraded in January 1994. Despite a lack of significant operating history with the cell design, the risk significance of the 120 Vdc system and a window of opportunity during a mid-cycle outage, engineering did not take prompt actions to confirm whether the batteries were degraded (Section 4.1).

- A Unit 3 auxiliary feedwater pump failed to start when called upon in August 1994, highlighting the failure of engineering to resolve a lingering deficiency with the pump's low suction pressure trip switch which had caused pump trips (Section 3.1).

Management Overview

The report highlights two significant areas of concern at Palo Verde - the conduct of operations and the resolution of identified problems. Both issues have been highlighted several times over the past year in inspection reports and management meetings and are recognized by the licensee as priority concerns. The identification of additional findings in these areas indicate that considerable additional management attention is warranted in these areas.

Summary of Inspection Findings

- Two examples of a violation for failures to take adequate corrective actions in accordance with 10 CFR Part 50, Appendix B, Criterion XVI, were identified (Sections 3.1 and 10.1).

- Three other violations identified were: a failure to follow procedures to ensure an RCS dilution evolution had stopped (Section 4.3), a failure to implement actions required by the TS when removing a startup nuclear instrument from service (Section 2.2), a failure to follow instructions for maintenance on the essential chiller (Section 9.3).

- One noncited violation involved the failure of a shift supervisor to adequately maintain control rooms logs (Section 2.4).

- One Unresolved Item was identified concerning the ability of a Unit 1 letdown isolation valve to perform its design function (Section 2.5).

- One Unresolved item was identified concerning the extended out of calibration of the Unit 2 boronometer (Section 5.4).

- Temporary Instruction 2515/125 concerning foreign material exclusion was closed (Section 7).

- One deviation was identified concerning the implementation of GL 88-05 commitments (Section 9.1).

- Violation 529/9423-01 was closed (Section 9.2).

- Unresolved Item 530/9426-01 was closed (Section 3).

Attachments:

Attachment A - Persons Contacted and Exit Meeting
Attachment B - List of Acronyms

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 operated at essentially 98 percent power the entire inspection period. Power continued to be limited to 98 percent due to two inoperable main steam safety valves. On September 14, 1994, power was reduced following a heater drain pump trip (Section 2.2). On September 15, the level control valve was repaired and power was returned to 98 percent.

1.2 Unit 2

Unit 2 began the inspection period at 100 percent power. On September 16, 1994, the unit began a shutdown for a steam generator tube inspection outage. On September 20, the unit entered midloop for installation of nozzle dams. On October 6, after completion of steam generator eddy current testing, midloop conditions were again entered for nozzle dam removal. At the end of the inspection period, Unit 2 was in Mode 3 preparing for a reactor startup.

1.3 Unit 3

Unit 3 began the inspection period and operated throughout the inspection period at essentially 100 percent power.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 RCS Drain Down and Midloop Operations - Unit 2

During the Unit 2 midcycle outage, the inspector observed the plant enter reduced inventory and midloop operations for the installation and removal of steam generator nozzle dams. The inspector noted several procedure and operations weaknesses and some operations strengths during the first midloop operation. The inspector determined that operations performance of the second midloop was an improvement over the first.

2.1.1 RCS Drain Down Operations

On September 19-20, 1994, the inspector observed the Unit 2 RCS draining operations. The inspector observed a variation in the level channels of the refueling water level indicating system (RWLIS) that appeared to be greater than the limits established in Procedure 42OP-2ZZ16, "RCS Drain Operations," Appendix D. When the operators halted the draindown for a 1-hour hold with RCS level just above the top of the hot leg, the inspector observed that the Train A wide range (WR) level indicator (LI) read approximately 10 inches higher than the Train B WR and the Train B narrow range (NR) LIs. The Train A WR LI indicated that level was above the hotleg, while the Train B NR and WR LIs indicated that level was below the top of the hotleg. The Train A NR LI was offscale high, since the NR LIs were designed to start reading at the top

of the hotleg. The maximum NR to WR level deviation allowed by Appendix D was 8 inches and, therefore, the Train A WR and Train B NR appeared to be outside the deviation allowed by Appendix D.

The inspector noted that the control room staff was unaware that the Train B NR LI had begun to read on scale and brought it to the attention of the shift supervisor (SS). The SS and the on-duty operations supervisor concluded that the Train A instruments were reading appropriately and that level was above the top of the hotlegs. This conclusion was based on their understanding that the difference in the two channels was due to pneumatic effects between the pressurizer and the vessel head and errors inherent in the channel which had the operating shut down cooling pump. In this case, the Train B pump was operating. In addition, operators had not drained a volume of water equivalent to the volume of water in the steam generators tubes. This would indicate that the level had not dropped below the top of the hotleg to allow the steam generators to drain. Therefore, the operators determined the NR channels were outside their operating band and should not be used.

The inspector noted that, while in a midloop condition, the NR LI and the level recorder monitoring level in the loop with shutdown cooling flow were fluctuating greater than 10 percent peak-to-peak of the indicator's range. The fluctuations appeared to have been caused by instrumentation noise typically seen on the RWLIS channels which electronically compensate for the operating shutdown cooling pump. The fluctuations exceeded the guidance provided in the recently issued Operating Procedure 40DP-90P28, "Dampening/Averaging of Instrument Fluctuations." The inspector determined that control room staff was not aware they were outside the limits of the procedure. Operating Procedure 40DP-90P28 was subsequently revised to allow the level fluctuations until the fluctuation problem of the level indications could be resolved. The licensee initiated Conditional Report/Disposition Requests (CRDR) to attempt to address the excessive noise seen in the compensated level channel.

The inspector observed some strengths during the RCS drain operation. The inspector noted that the licensee placed a work control supervisor in the control room back office to limit the activity in the control room and allow the control room supervisor (CRS) to monitor control room activity. The inspector observed that the control room staff aggressively performed inventory comparisons between the RCS being drained and the refueling water tank (RWT) being filled. The control room staff used all level indications including the emergency response facility data acquisition display system displays, control board indicators, and reactor vessel level monitoring system heated junction thermocouples to safely drain to midloop.

The inspector noted that sections of Procedure 42OP-2ZZ16 did not provide appropriate guidance to allow the operators to smoothly perform the evolution. Control room personnel required operations management's interpretation of procedure steps to perform the drain operation. In addition, operations management subsequently requested that operations standards clarify the intent of sections of the procedure. The procedure was revised to provide

clarification prior to the October 6 drain down to midloop. While the use of these resources by the control room personnel was seen as a strength, it highlighted the weaknesses in a procedure governing one of the more critical plant evolutions.

2.1.2 October 6 RCS Drain Down

The inspector observed the October 6, 1994, RCS drain operation and concluded that the operators displayed a greater attention to detail in monitoring level comparisons required by Procedure 42OP-2ZZ16, Appendix D, and the control room communications and formality were improved over the September 19 drain down operation. The inspector noted that there was increased control room activity. At one time, approximately 10 people were in the "horse shoe" area; however, the RO designated to monitoring the drain down appeared focused on the evolution.

2.2 Startup Channel Inoperable - Unit 2

On September 27, 1994, with the Unit 2 in Mode 5, operations removed a startup channel from service and failed to comply with the requirements of the TS action statements.

During performance of calibration Procedure 36MT-9SE07, "Excore Startup Channel Calibration," the CRS reviewed TS 3.1.2.7, "Boron Dilution Alarms," and declared Startup Channel 1 and the associated boron dilution alarm inoperable at 8:54 a.m. The CRS failed to note that TS 3.1.2.7 required that operators determine the boron concentration periodically at the frequency defined in the core operating limits report. The core operating limits report required that the boron concentration be determined every two hours. After the calibration was completed, a channel check was performed on the startup channels and operations declared the Startup Channel 1 and boron dilution alarm operable at 4:30 p.m.

During shift turnover, the oncoming CRS noted a calibration had been performed on a startup channel and determined that the periodic boron concentration verifications were not performed. The oncoming operators verified the boron concentration using the boronometer. A subsequent RCS sample also revealed that the RCS boron concentration was nearly the same as when the startup channel was declared inoperable. The licensee later determined the boronometer calibration was past due and declared the boronometer inoperable (discussed in Section 4.4).

The licensee's review indicated that the initial boron concentration was determined, but the boron concentration was not verified every two hours. The failure of operations to verify RCS boron concentration every two hours is a violation of TS 3.1.2.7 (Violation 529/9431-02).

The licensee performed several followup actions: initiated a CRDR to evaluate the event, submitted a licensee event report 50-528/94-03, added a note in several procedures to clarify action taken when one startup channel is

declared inoperable, and issued a night order to all three units discussing the event and reinforcing managements expectations on performance of surveillance.

The inspector noted that an independent verification of the CRS's evaluation of the TS was not performed by the control room staff nor the SS. The inspector concluded the safety significance of the event was low since the reactor had approximately 20 percent shutdown margin and no RCS dilutions were performed. While the inspector noted the completed corrective actions performed by the licensee, the inspector also noted that this was the second time in less than a year that a Unit 2 operations crew failed to recognize and comply with the requirements of TS action statements (NRC Inspection Report 50-529/93-48).

2.3 Auxiliary Feedwater (AFW) Pump Potentiometer - Unit 1

During a plant walkdown on October 4, 1994, the inspector observed the speed control potentiometer at the RSP for the steam-driven AFW pump set at zero. The licensee reviewed their procedures and determined that unlike the control room, there was no specific setting requirement for the potentiometer at the RSP.

The inspector concluded that there was no safety concern since the pump would continue to run regardless of whether the potentiometer was set at the maximum or minimum speed when control for the pump was transferred from the control room to the RSP. In addition, the inspector noted that the pump is either tripped by the evacuation procedure or used as a backup to the electric driven pump, depending upon why the control room was evacuated.

Operations standards informed the inspector that they planned to evaluate the desired position of the potentiometer.

2.4 Inoperable AFW Pumps - Unit 1

On September 22, 1994, the inspector noted that the SS had not recognized that both the Train A essential steam-driven AFW pump and the Train B motor-driven AFW pump had been inoperable at the same time for about 15 minutes on the previous day. The inspector also noted that the licensee had already identified the discrepancy and had made a late entry in the logs that both trains of AFW pumps had been inoperable.

This situation occurred when the Train B emergency diesel generator (EDG) was considered inoperable after it had tripped during testing due to problems in the pneumatic test trip system. During the initial troubleshooting, technicians discovered that the problem had not affected the ability of the EDG to start either automatically or manually. However, the SS carried the EDG as inoperable, anticipating subsequent repair efforts. The inspector noted that prior to the start of repairs to EDG, the steam-driven AFW pump was removed from service for about 15 minutes to allow testing of the pump's trip throttle valve. While both the Train B EDG and the Train A AFW pump would

have been available during an event, both AFW pumps should have been considered inoperable for the 15 minutes.

With the Train B EDG and Train A AFW pump inoperable, the licensee should have considered the Train B AFW pump also inoperable. Therefore, the licensee should have entered a six hour shutdown limiting condition for operations (LCO) action of TS 3.7.1.2.

The inspector discussed the sequence of events with operations management. Based on this review, the inspector had the following conclusions:

- The SS considered the Train B EDG to be operable prior to removing the Train A AFW pump from service for testing and, therefore, believed that the Train B AFW pump was operable. Although the determination was not logged, he subsequently considered that the EDG had been inoperable for the duration of the event.

- The SS did not appropriately consider the potential risk of removing the Train A AFW pump from service for testing with a potential problem with the Train B EDG. In this case, the Train A AFW pump was out-of-service for the surveillance test, and if the operability determination for the EDG was wrong, both safety-related trains of the AFW system would have been inoperable. This would be an extremely vulnerable situation since a total loss of AFW was the highest contributor to core damage frequency.

- The SS did not properly log entering and exiting TS action statements as required by the operations log keeping procedure. Additionally, the SS did not accurately describe the decisions he made concerning the operability of the EDG which contributed to inadvertently entering the action statement for two inoperable AFW pumps.

The licensee initiated a CRDR to investigate the incident and determine corrective actions. The licensee also concluded that the SS log keeping practices contributed to the error and that the actual safety significance of the event was low. The licensee also planned to discuss this event during operations department training. The inspector concluded that the licensee's corrective actions were appropriate.

The failure to properly log entering and exiting TS LCOs is a violation for failing to follow procedures. This violation is not being cited because the criteria specified in Section VII.B of the enforcement policy were satisfied.

2.5 <u>Letdown Line Isolation Valve Leakage - Unit 1</u>

During a routine tour of the control room, the inspector noted that the letdown to regenerative heat exchanger isolation Valve CH-515 had a caution tag stating that the valve leaked 41 gallons per minute at normal operating pressure and could not be used to isolate the letdown line. The inspector

identified that Valve CH-515 received signals to shut on both a safety injection actuation signal and a high regenerative HX outlet temperature. The inspector was concerned that the leakage past Valve CH-515 may prevent it from performing its safety function. Based on this concern, the inspector conducted a review to determine if the condition had been properly documented, evaluated, and that repairs were scheduled in a reasonable time.

The inspector determined that the valve leakage was first identified in December 1992 and a WO was written to perform a diagnostic test of the valve. This WO was scheduled for Refueling Outage 1R4 in the fall of 1993. The inspector discovered that the diagnostic test was not performed during refueling outage 1R4. The inspector also noted that the WO was the only place the problem was documented. Based on the inspector's questions, the licensee conducted an investigation to determine why the work was not performed during the refueling outage 1R4 and to determine if there was any immediate operability concern.

The licensee determined that during the November 1993 outage, there was a meeting with valve services, engineering, I&C maintenance, outage management, and operations management to discuss the problem with Valve CH-515. During the meeting, the groups had different concerns about the condition of Valve CH-515 and what were the appropriate actions to take. For example, engineering wanted to perform a diagnostic test on the air operator for the valve to determine the extent of the problem. Outage scheduling was concerned because the time to do the work was limited (about 2 days). I&C maintenance did not want to do the work because there was a possibility that the valve may not be leaking and they were concerned about the high dose rates in the area. The maintenance group thought the valve did not leak because it was used as an isolation valve during the performance of the local leak rate test (LLRT) of Valve CH-516. Operations was concerned about the ability of the valve to perform its function should the work not be performed.

At this meeting, these groups reached a consensus and decided that the diagnostic test would not be performed and a leak test would be done at normal operating pressure to determine if the valve actually leaked. If the valve leaked, the diagnostic test would be scheduled for the first available outage. This decision was based on the fact that there was a redundant valve in the letdown line, CH-516, that would shut on a safety injection actuation signal and was known not to leak based on satisfactory performance of the last LLRT.

The inspector reviewed the licensee's basis for not promptly correcting the problem and had the following observations:

- The licensee had not documented their operability determinations either when the valve was initially determined to be leaking, nor during 1R4 when the determination was made to continue to the next outage with the degraded condition.

- The system engineer did not perform a thorough review of all available design basis information to ensure that the condition was acceptable.

- The licensee did not consider the potential increase in core damage frequency by operating with a leaking isolation valve for an entire operating cycle. The inspector noted that a letdown line break outside of containment was the highest contributor to the overall frequency of an inter-system loss of coolant accident. Since Valve CH-515 was known to leak, a single failure of Valve CH-516 would prevent complete isolation of this leak.

- The licensee was incorrect in their assumption that a satisfactory leak test on Valve CH-516 demonstrated that Valve CH-515 probably did not leak. During the LLRT of Valve CH-516, pressure was applied to Valve CH-515 in the direction that would help seat the valve. During normal operation, system pressure is applied under the seat and would tent to open the valve.

- Plant management's decision to defer the maintenance appeared to be primarily based on a concern with the high dose rates in the area of the valve. The licensee could not recall if they had discussed what actions could be taken to minimize the dose when the inspector questioned their decision to defer the maintenance.

In response to the inspector's findings, the licensee conducted an operability determination and concluded that the existing condition was not outside any design basis assumptions. The licensee could not find any design requirement on leakage for Valve CH-515 and was confident that there was not an operability concern.

On November 18, subsequent to the end of the inspection period, the inspector identified that a hand switch for Valve CH-515 was located on the remote shutdown panel. The inspector also identified that the switch was called out in the operating procedure for plant shutdown outside of the control room due to a control room fire. The licensee concluded that their 10 CFR Part 50, Appendix R, evaluation credited Valve CH-515 as a fire protected valve used to isolate letdown and allow control of reactor coolant system inventory. The licensee initiated compensatory measures to ensure that letdown could be isolated in the event of a control room fire. This issue, and the failure to take timely action to address a condition adverse to quality, will be addressed in a future report (Unresolved Item 528/9431-01).

3 OPERABILITY OF THE NONCLASS AFW (NAFW) PUMP - UNITS 1 AND 3 (92903)

3.1 Background

On August 31, 1994, during the recovery following a Unit 3 reactor trip, operators attempted to start the NAFW pump to allow them to shutdown the safety-related AFW pumps. The NAFW pump tripped shortly after the start

attempt and tripped again following a second attempt to start the pump. This issue was discussed in NRC Inspection Report 50-530/94-26 and was designated Unresolved Item 530/9426-01.

During the licensee's initial followup evaluation, the licensee was unable to determine the specific cause. They speculated that the pump had tripped due to a spurious low suction pressure switch actuation. A similar condition had occurred in Unit 2 in March 1992. The licensee had found that suction pressure oscillated following the start of the NAFW pumps and had in the past caused a low suction pressure trip. In response to the Unit 2 NAFW pump trip, the licensee removed the low suction pressure trip switch (PSL-9) from service in Unit 2, but had left the switches in service in Units 1 and 3. In response to the recent Unit 3 NAFW pump trip, the licensee removed Switch PSL-9 from service in Units 1 and 3.

The inspector questioned whether the Unit 1 and 3 pumps were operable with Switch PSL-9 in service. Additionally, the inspector reviewed the licensee's followup of the Unit 2 NAFW pump trip to understand why no action had been taken with the Unit 1 and 3 pumps prior to the August 1994 Unit 3 NAFW pump trip.

3.1.1 System Design

The NAFW pump was originally installed as a nonsafety-related startup feedwater pump. It was installed in the turbine buildings and received normal power from a nonvital bus. Subsequently, due to the safety significance of feedwater systems at Palo Verde, the NAFW pump was included in the TS with a 72 hour out-of-service time. A modification was made to allow the pump's motor to be supplied from a vital bus. The supply to the NAFW pumps from the condensate storage tank (CST) is normally isolated by two motor-operated valves installed at the code break between the seismic and nonseismic qualified sections of the supply line. The pumps were provided with a low suction pressure trip switch (PSL-9) designed to actuate if suction pressure dropped below 2 psig.

3.1.2 Licensee Followup of the March 1992 Unit 2 NAFW Pump Trip

In March 1992, the Unit 2 NAFW pump tripped while operations was recovering from a reactor trip. A CRDR 2-2-0114 was initiated to investigate the cause of the pump trip. The licensee performed testing on the NAFW pump and found that during a pump start at full flow conditions, pump suction pressure dropped below the 2 psig setpoint of Switch PSL-9. This condition was not seen during routine testing through the miniflow return line since the flow established was considerably less than full flow. As a result, the suction pressure drop was not as pronounced.

As immediate corrective action, the licensee disabled PSL-9 in Unit 2. This was accomplished by racking out the breaker to the train's miniflow recirculation valve, using a clearance request. The licensee included a

10 CFR 50.59 safety evaluation in the CRDR which concluded that the change was acceptable. The licensee did not initiate a temporary modification request.

The licensee initiated action to test the Unit 1 and 3 NAFW pumps to establish if they were susceptible to the same conditions. On March 31, the licensee performed a test on the Unit 3 NAFW pump and found that suction pressure did not drop below 8 psig. The test was performed through a full flow orifice return to the CST. The licensee documented that a test would be performed on Unit 1 when it exited an outage that it was conducting.

3.1.3 Corrective Actions

The inspector noted that between March 1992 and August 1994, an evaluation for a permanent fix was carried under two CRDRs and three engineering evaluation reports (EERs). The evaluations included some proposals that were subsequently reconsidered. A proposal to eliminate the Switch PSL-9 trip was dropped when a probabilistic risk assessment evaluation concluded that a properly operating suction pressure trip had a net safety benefit. The inspector noted that this evaluation took almost one year to complete. A proposal to close the root valve prior to starting the pump was also considered. The inspector concluded that the identification and implementation of corrective actions for the March 1992 Unit 2 NAFW pump trip were not timely.

At the time of the Unit 3 NAFW pump trip in August 1994, WOs had been generated to install needle valves in the sensing line to act as a pressure dampening device. The inspector noted the following:

- Pressure dampening devices had been used in the past in Units 1 and 2. They were removed in 1989 when it was discovered that they became clogged and affected the ability of technicians to calibrate the instruments.

- Each of the pressure switches appeared to have been installed with a small, in-line orifice designed to act as a pressure dampener.

Based on these observations, the inspector was not confident that the installation of a needle valve would have been an effective corrective action to prevent recurrence of low suction pressure trips.

In early August 1994, the corrective actions for the Unit 2 NAFW pump trip was transferred to the newly established I&C maintenance engineering section. Subsequent to the Unit 3 NAFW pump trip, the I&C engineer did a review of the performance of Switch PSL-9 in all three units. The engineer found the following:

- Switch PSL-9 had been found within tolerance during its routine calibration only once in all three units.

- The Switch PSL-9 switches had been replaced at least four times; once in Unit 1 and three times in Unit 2.

- The instruments used in the Switch PSL-9 application were close to an over ranged state while the pump was in standby, possibly contributing to their lack of reliability.

The inspector noted that these findings were readily available, but had not been previously identified in the review performed by the system engineers. The inspector concluded that a reasonable review of pump trips initiated by Switch PSL-9 should have identified and assessed this information.

3.1.4 Unit 1 Operability Test

The inspector noted that the operability test performed on the Unit 1 NAFW pump in response to the Unit 2 pump trip was performed 20 months after the Unit 2 trip (November 1993). The inspector questioned why the test had not been performed sooner. The former system engineers noted that Unit 1 was in a refueling outage in March 1992. As documented in CRDR 2-2-0114, they had intended that the test be performed as Unit 1 returned to power following its refueling outage. They could not recall why the test was not performed at the time. The system engineers stated that a test was not performed while at power because they were concerned about using additional TS LCO outage time on the pump while Unit 1 was operating. Additionally, they noted that the Unit 1 NAFW pump had been operated routinely several times without tripping.

The inspector noted that this justification had not been documented in the CRDR. Regardless, the inspector did not find this to be adequate justification for waiting 20 months to perform the operability test. The inspector noted that the Unit 1 NAFW pump had tripped on low suction pressure in November 1987 (WR 217331), indicating that it may have been susceptible to low suction pressure trips. In addition, the test was to be performed through a full flow recirculation valve return to the CST. The inspector noted that if the test was performed with a quarterly pump performance test, the additional out of service time would have been minimal and the pump would have been available to the control room with the local manipulation of two valves.

The inspector reviewed the test performed in November 1993 on Unit 1. The inspector found that the suction pressure trace showed that pressure dropped below the 2 psi setpoint of Switch PSL-9. The inspector also noted that it was not clear from the WO documenting the test what the test conditions were. The test did not document initial CST level, which represented initial suction pressure, nor did it document system flow. Additionally, although the system engineers accepted the test as an adequate justification for pump operability, they did not document the basis for their conclusion, nor did they question why the pressure switch did not actuate when pressure dropped below its setpoint.

The inspector found no documented evaluation of the differences between the responses of the NAFW pumps. The system engineers could not identify any configuration differences between the three Units which would explain the different responses. Overall, the inspector found that the operability evaluation of the Unit 1 and 3 pumps to be weak and poorly documented.

3.1.5 Cause of the Unit 3 NAFW Pump Trip

The inspector noted that there had been no action taken to review the cause of the recent Unit 3 NAFW pump trip. It appeared that the review had been added to the older evaluations. The inspector discussed the Unit 3 trip with the I&C engineer assigned with responsibility for Switch PSL-9 performance. The I&C engineer noted that in the testing of the Unit 3 NAFW pump following its trip, a technician had discovered what appeared to be the in-line pressure dampening device not in its original position but in the sensing line at the test connection. The I&C engineer considered that the loss of this dampening device may have made the pressure switch more sensitive to the suction pressure swings following a pump start. The licensee had not established whether the pressure dampening device was installed in either of the Unit 1 or 2 PSL-9 switches.

3.1.6 Out-of-Tolerance Review of PSL-9

The inspector noted that Switch PSL-9 had not been included in the licensee's out-of-tolerance review program. The licensee's program flags instruments which have a history of being out-of-tolerance to engineers for review. Switch PSL-9 was not included because the switch had been classified as nonsafety-related. The inspector found this inconsistent with the application of the switch in an AFW train included in the TS. The licensee stated that they would include the switch in the out-of-tolerance review program.

3.1.7 Safety Significance

Although the NAFW pump was not installed as a safety-related pump, it was included in the TS in response to the significance of the AFW system at Palo Verde. The failure of the AFW system is the most significant contributing system to the core damage frequency due to the lack of primary side power operated relief valves at Palo Verde.

The inspector considered that the degraded condition of the PSL-9 switch was a significant condition adverse to quality and that actions to determine the cause of the condition and take corrective actions to prevent recurrence had not been timely. This is a violation of 10 CFR Part 50, Appendix B, Criterion XVI (Violation 529/9431-03). This closes Unresolved Item 530/9426-01.

4 ONSITE RESPONSE TO EVENTS (93702) & ONSITE ENGINEERING (37551)

4.1 Degraded Safety-Related Batteries - Unit 2

4.1.1 Testing in September and October 1994

On September 23, 1994, with Unit 2 shutdown for a midcycle outage, the licensee determined that the capacity of the Unit 2 A and C 125 volt, safety-related, DC batteries were 90.9 and 90.3 percent, respectively. During the last two years, the licensee has installed AT&T Model L-1SH round cell batteries in all the units. Each unit has four safety-related banks of batteries and each bank has a total of 60 cells. The licensee was performing the initial capacity test of the Unit 2 A and C banks which were installed in May 1993. Since AT&T guaranteed these batteries would have a minimum of 100 percent capacity at the end of 40 years, the latest test results indicated that the cells may be degrading.

The battery capacity was determined by a constant rate discharge of 530 amperes for 2 hours. A battery terminal voltage of 105 volts after 2 hours corresponds to a capacity of 100 percent. The acceptance criteria for the capacity test was the TS limit of 90 percent. The licensee considered the A and C battery banks to be operable since the capacity of the batteries was greater than the TS limit. On September 28, the licensee verified the test results and concluded that the batteries were actually degrading.

Based on the unexpected battery degradation, on October 1, the licensee conducted capacity tests of the Unit 2 B and D battery banks and the installed spare batteries in Units 1 and 3. Based on these tests, the licensee concluded that the problem with the batteries was limited to Unit 2. The licensee conducted additional tests of the Unit 2 batteries which indicated continued degradation after each capacity test and that the anticipated capacity of all four banks of safety-related batteries was less than the TS limit. The licensee subsequently declared all four battery banks inoperable.

Prior to Unit 2 entering Mode 4, the licensee replaced the four weakest cells in Battery Banks B and D, 11 of the weakest cells in Bank A and 12 of the weakest cells in Bank C. These replacements increased the projected battery capacities to slightly above 85 percent for each bank, which was greater than the calculated worst case accident load requirements for each bank.

On October 13, the Office of Nuclear Reactor Regulation issued an emergency TS amendment which allowed the licensee to declare the Unit 2 Class 1E 125 Vdc battery banks operable with lower battery capacities than specified in TS 4.8.2.1.e. The amendment allowed the unit to operate approximately 3 1/2 months (until the fifth refueling outage scheduled to begin on February 4, 1995).

The inspector observed the resolution of the problem with the batteries and had the following conclusions:

- The licensee appropriately evaluated whether the problem was transportable to the Unit 1 and 3 batteries. Thus far, the licensee considered the problem only related to the Unit 2 batteries, but was continuing to re-evaluate this conclusion based on the latest available information.

- The licensee made the appropriate operability determination when engineering presented new information that affected the A and C battery banks.

- The licensee conservatively controlled reactivity changes with all four battery banks inoperable.

- The licensee conducted an aggressive and comprehensive root cause of failure analysis.

- The licensee took appropriate compensatory actions to ensure that the batteries would be able to provide the design basis loads.

The licensee was conducting a formal root cause of failure analysis to determine why the cells were degrading during the battery discharge/recharge cycle. The licensee plans to submit a licensee event report to document the problem with the batteries, their initial corrective actions, and the results of the root cause of failure analysis.

4.1.2 Degraded Vital Battery Individual Cell Voltage - January 1994

The inspector also conducted a review of the licensee's actions following the initial capacity test of the Unit 2 D battery bank in January 1994 which indicated abnormally low individual cell voltages (ICV) for two cells. During this review, the inspector concluded that the licensee did not take prompt corrective actions to resolve this deficiency.

On January 31, 1994, the licensee conducted the first capacity test of the replacement Unit 2 round cell batteries after they were installed in May 1993. The ICV of two cells (17 and 36) at the end of the test were abnormally low. The ICVs were 1.15 and 1.28 volts respectively, and the expected ICV was about 1.75 volts. The licensee initiated a "category 5" (lowest level evaluation) root cause of failure CRDR to evaluate this condition.

The inspector reviewed the licensee's evaluation and noted that the licensee's electrical engineering group determined that the condition was not a safety concern and that replacement of the cells could be deferred until the 1995 refueling outage. This decision was based on the following:

- Engineering reasoned that there was a high probability that the test results for these two cells were invalid because this type of rapid decrease in ICV was not evident during previous capacity tests of the

round cell batteries. AT&T concluded that there was a 90 percent probability that the test data was wrong.

- Engineering believed that if the test data was accurate, the problem was limited to cells 17 and 36. This conclusion was based on the fact that 100 minutes into the test, the ICVs for these two cells started to decrease faster than the other cells and continued to rapidly decrease until the test was stopped 20 minutes later.

- Engineering determined that the D battery could meet its design basis load even if cells 17 and 36 failed and cell reversal occurred.

The inspector had several discussions with the electrical engineering group to determine if the decision to defer the root cause evaluation of cells 17 and 36 was appropriate. The inspector noted that:

- Engineering took no actions to confirm their conclusion that the test data for cells 17 and 36 were invalid.

- Cells 17 and 36 were not scheduled to be replaced during the first available outage but were scheduled to be replaced during the refueling outage scheduled for early 1995.

- On February 10, engineering and AT&T recommended that cells 17 and 36 be replaced. At that time, there was over a month that the unit was shutdown and another test could have been performed to validate the original data or the cells could have been replaced. However, work to either test or replace the batteries was not inserted into the schedule. Battery replacement was estimated to take approximately 8 hours.

The inspector noted that the engineers did not have a sense of urgency to validate the test results and to ensure that there was no safety concern with the overall performance of the batteries. For example, the supervisory review of the CRDR indicated that there was no safety concern because the minimum acceptance requirements were met. However, the inspector noted that there should have been a broader safety concern since there was limited experience with the AT&T round cell batteries in nuclear applications, there was no technical basis to disregard the test results, and this degradation was contrary to the stated and expected behavior of these batteries. An appropriate approach would have been to assume that the test results indicated that the Unit 2 cells were degraded and to conduct an aggressive evaluation to assess the extent of degradation. This type of approach may have alerted the licensee to the overall degradation of the batteries that resulted in all four battery banks subsequently being declared inoperable.

The inspector noted that engineering appeared to be comfortable with an evaluation that was based on assumptions without actual facts to support the conclusions. The inspector was concerned because an over reliance on engineering assumptions and calculations was similar to the weakness

identified related to a bent connecting rod in the Train B EDG in Unit 3 (NRC Inspection Report 50-530/94-16).

The inspector concluded that engineering did not take reasonable actions to verify that any potential problem with the battery was limited to cells 17 and 36. The inspector also concluded that the licensee did not take prompt corrective actions to identify and correct a condition adverse to quality. This was a violation of 10 CFR Part 50, Appendix B, Criterion XVI (Violation 529/9431-04).

4.2 Heater Drain Pump Trip - Unit 1

On September 14, at approximately 10 p.m., the Train A heater drain pump tripped on low level in the associated heater drain tank. The Train A main feedwater pump suction pressure dropped to 300 psig (the trip setpoint is at 255 psig) during the transient. Operators lowered reactor power and cross connected the heater drain tanks so that the Train B heater drain pump was controlling level in both heater drain tanks. The licensee determined that the event was caused by the Train A heater drain tank normal level control valve sticking 100 percent open. This caused the level in the tank to rapidly lower until the trip setpoint was reached.

The inspector observed portions of the repairs to the valve, including the prejob briefing and the restoration of the heater drain system to a normal lineup. The inspector concluded that the evolution was well planned and controlled by the operators. The inspector also noted good involvement from the maintenance engineer. The defective parts were retained and CRDR 1-4-0298 was initiated to perform a root cause evaluation of the event.

The inspector reviewed the operating logs and noted that during the transient an auxiliary operator (AO) attempted to shut the level control valve by isolating the local instrument air supply valve to the actuator. This was attempted because the AO thought that the valve would shut on a loss of instrument air. The inspector found that the valve fails shut on a loss of instrument air (i.e., if the main instrument air supply valve is shut), but if the air is isolated locally to this particular actuator the valve will fail in the "as-is" position. The inspector noted that the on-shift crew was not aware of this difference. The inspector then questioned the assistant shift supervisor concerning how the valve operated and if there was a training issue that needed to be addressed. The assistant shift supervisor agreed with the inspector that there was some confusion as to how the level control valve operated and conducted a briefing with his crew.

About four weeks after the event, the inspector reviewed the CRDR and noted that the training issue was not addressed. The inspector was concerned that the misconception with operation of the level control valves may also exist in several other crews and was not being addressed. The Unit 1 operations department agreed with the inspector that they missed the opportunity to review the issue and wrote a separate CRDR to evaluate the potential training issue. The inspector concluded that these actions were appropriate.

4.3 Dilution Event - Unit 2

On September 7, 1994, with Unit 2 at approximately 100 percent power, an RO commenced an addition of 100 gallons of water for dilution of the RCS at a rate of 85 gallons per minute in a routine operation to raise average RCS temperature. An AO distracted the RO from the dilution by asking a question about a clearance being hung on a charging pump. While the RO was answering the AO's questions, the chemical and volume control system did not automatically stop at 100 gallons as it should have and the dilution continued unmonitored for approximately three minutes. A high pressure alarm on the volume control tank alerted the RO that the dilution had not automatically stopped. The RO immediately stopped the dilution.

The RO determined that an over-dilution of 240 gallons of water had occurred. The RO calculated that a boration of 40 gallons of borated water from the RWT was required to compensate for the additional water added. A second RO verified the calculation was correct. The operators added the borated water and monitored the parameters of RCS temperature, power, and axial shape index. The operators observed the expected plant response for the effect of the 100 gallon dilution which was originally intended. The inspector reviewed the plant trends following the event and noted no adverse effects.

Procedure 42OP-2CH01, Revision 13, "Chemical and Volume Control System Normal Operations," step 9.3.12, requires that once the desired volume had been added to the RCS, a verification that the automatic makeup Valve (CHN-FV-210X) has closed is to be performed. The RO performing the dilution did not ensure Valve CHN-FV-210X closed after the desired volume of 100 gallons had been added to the RCS. The failure of the RO to follow procedures is a violation of TS 6.8.1 (Violation 529/9431-05).

The operator involved in this event did not notify his supervisor of the over-dilution. The Shift Technical Advisor (STA) was informed during the shift change process. Subsequently, the on-coming shift supervisor was informed by the STA and the incident was reported to plant management. In response to the event, licensee management initiated an event investigation which was led by the assistant to the Vice President of Nuclear Production.

The inspector reviewed the licensee incident investigation and nuclear fuel management evaluation for the event. The inspector noted the licensee performed a very thorough investigation and root cause analysis. The inspector agreed with the licensee's conclusion that the event was a reactivity management issue and was very similar to the Unit 1 RCS drain down event (NRC Inspection Report 50-528/93-248; 50-529/93-48; 50-530/93-48). There were several similar aspects to the drain down event: operators had grown complacent in performing a routine but critical evolution, the event involved a "work around" condition in that Valve CHN-FV-210X had a history of not terminating dilutions at the set addition, and the operator had allowed other work to distract a critical evolution.

Recognizing the similarity between the two events, the licensee reviewed the actions taken in response to the drain down event and concluded that they had not been fully effective. On October 19, after Unit 2 had completed its midcycle outage, the Executive Vice President issued a memo to operations listing several revised expectations for the conduct of operations and stated that he expected a step change in their performance. The revised expectations included that the SS and not the ROs or CRS should be managing the actions of the AOs. Further, the CRS should directly supervise and authorize every control board manipulation. The inspector found these actions to be appropriate.

In summary, the inspector noted that while this was a repeat of a previous event, the licensee recognized the significance of the event and performed a detailed, high level evaluation and took prompt and thorough action without prompting from the NRC.

5 MAINTENANCE OBSERVATIONS (62703)

5.1 EDG Maintenance - Unit 3

On October 5, 1994, the inspector observed several preventative maintenance tasks on the EDG A in Unit 3. The preventative maintenance tasks were part of online maintenance that was scheduled to take about 12 hours. The inspector observed portions of an inspection of the diesel building normal exhaust fan, replacement of the zinc anodes for the air intercooler and fuel oil cooler, and replacement of the seal gaskets on a starting air system shuttle valve.

The inspector noted good supervision in the field, good interface with the maintenance engineer, and good work practices by the technicians. Additionally, the planning and scheduling of the work was thorough and well coordinated between maintenance groups.

5.2 Fiber Optic Card Replacement - Unit 2

On September 22, 1994, the inspector observed electrical maintenance replace heat damaged fiber optic transmitter/receiver boards in EDG A in Unit 2. The heat damage was caused by components on the circuit board. The inspector questioned the technicians about the initial bench test and determined the technicians were knowledgeable about the bench test and work package. The inspector observed proper independent verification of landing the leads to the board. The inspector observed no deficiencies.

5.3 4KV Circuit Breaker Alarm Change - Unit 2

On September 22, 1994, the inspector observed electrical maintenance workers performing a design change in Unit 2 on the 4.16 KV (kilovolt) bus breakers. The change involved installation of circuitry to cause an alarm in the control room if breaker charging springs are not charged and the breaker is racked in. The inspector noted that the technicians were knowledgeable about the work package and design change and the inspector observed no problems with the post

maintenance test. The inspector concluded the overall performance by electrical maintenance was good.

5.4 Boronometer - Unit 2

On October 3, 1994, operators were notified that the boronometer was out of calibration (OOC). The boronometer had been OOC since February 1993. As of the end of the inspection period, the boronometer was still OOC.

TS 3.1.2.7 action statement requires, in part, that RCS boron concentration be verified by either boronometer or RCS sample. The licensee initiated a CRDR to determine the cause and effects of the missed calibration. The inspector will review the licensee's evaluation of the OOC boronometer and followup of the OOC program (Unresolved Item 529/9431-06).

6 SURVEILLANCE OBSERVATION (61726)

6.1 Startup Channel Alarm Surveillance - Unit 2

On September 28, 1994 the inspector observed operations personnel perform Procedure 42ST-2ZZ24, "Startup Channel High Neutron Flux Alarm Inoperable 3.1.2.7," Appendix B. Operations appropriately initiated a temporary procedure change in accordance with procedures to correct a step that referenced the wrong section of the core data book. In addition, operations contacted reactor engineering for assistance in the determination of boron worth when the current boron concentration was beyond the limits of the table. The inspector noted proper independent verification of the calculation steps of the procedure. The inspector concluded that operators demonstrated several strengths in the performance of the surveillance.

7 FOREIGN MATERIAL EXCLUSION (FME) CONTROLS - TEMPORARY INSTRUCTION 2515/125

The inspector performed an inspection to determine whether the licensee had effective procedures to prevent foreign material from inadvertently entering safety systems during maintenance activities, outages, and routine operations. This inspection was prompted due to recent incidents at several utilities which indicated a programmatic weakness in the area of FME controls.

The inspector reviewed the licensee's FME procedure, observed ongoing maintenance activities, reviewed the licensee's controls for transient material and radiation protection postings in containment during outages, conducted a containment closeout inspection prior to Unit 2 entry to Mode 4, and reviewed past events related to FME controls. Based on this review, the inspector had the following conclusions:

- WO instructions for routine preventative and corrective maintenance activities included either specific steps to install FME devices or general precautions to observe the requirements of FME procedure.

- Maintenance personnel were very sensitive concerning the need to maintain system cleanliness. Several technicians displayed a good understanding of the requirements of the FME procedure. The inspector observed FME devices being installed during work in progress.

- The licensees FME control program included higher levels of control for work in the refueling cavity, spent fuel pool area, and in other critical systems such as the main turbine. The inspector noted that the refueling group was very sensitive to maintaining a high level of control over material in this area. The inspector observed strong management involvement in these controls and a very low threshold for identifying concerns. For example, during the last refueling outage in Unit 1, several small pieces of debris were identified in the reactor vessel and a comprehensive evaluation of the condition was performed (NRC Inspection Report 50-528/93-43, Section 7).

- The licensee's containment cleanliness inspection required a walkdown of the containment prior to entering Mode 4. This walkdown was comprehensive, included specific objectives, and was performed by the maintenance and operations departments. The only material left in the containment was needed to perform testing and inspection required in Mode 3. The inspector performed an independent walkdown and did not identify any discrepancies that the licensee had not already identified. Additionally, all the loose material left in the containment was being tracked by outage management.

- The licensee had several engineering evaluations to control the amount of transient material in the containment while shutdown. These evaluations provided controls on the amount of bump hazard pads, radiological protection (RP) posting material, plastic tubing, tie wraps, and herculite that was allowed in the containment. There was also a procedure that required the removal of all RP postings prior to Mode 2 operations. The inspector did not identify any transient material that was not evaluated by the licensee or any loose RP postings during the containment walkdown.

The inspector was aware of only a few recent events that were caused by foreign material. The first involved a piece of grit in a motor operated valve actuator that prevented the valve from closing after it had opened (NRC Inspection Report 50-528/93-26, Section 11). The second involved resin that was found in the instrument air system and prevented a steam bypass control valve from properly opening (NRC Inspection Report 50-530/94-26, Section 4.2). The inspector concluded that these were isolated events and that the licensee's corrective actions were effective in both cases. Overall, the inspector concluded that the licensee had an effective FME program.

8 SIMULATOR OBSERVATION (41500)

On October 7, the inspector observed two graded simulator evaluations. The inspector reviewed the scenarios, observed the performance of the crew and evaluators, and observed the critique of individual operator and overall crew performance.

The inspector noted that both scenarios involved multiple casualties that required entry in numerous procedures and good diagnostic skills. The first scenario ended with a small break LOCA from a reactor coolant pump seal and the second led to an intersystem LOCA from the reactor coolant pump high pressure cooler to the nuclear cooling water system.

The inspector noted that both crews successfully performed the critical tasks. The inspector also observed good command and control by the CRSs, good team diagnostic skills, and effective communications. The inspector did note some minor communication deficiencies such as not using alpha numerics when identifying system trains and not using system identification when directing control board actions. The training evaluators also noted the communication deficiencies and several other minor performance issues. The inspector noted that these issues were discussed with the crews and appropriately resolved.

9 FOLLOWUP - MAINTENANCE (92902)

9.1 Boric Acid Corrosion Prevention Program

The licensee implemented some of the commitments in Procedure 73TI-9ZZ13, Revision 7, "Visual Examination for Leakage." The licensee used this procedure to implement the commitments to develop procedures that incorporate the principal leak locations for visual inspection on a routine basis and for conducting these examinations.

The licensee stated that all ASME Section XI Class 1 components were inspected and, therefore, encompassed the list of potential leak locations. In subsequent discussions with the licensee, the inspector learned that there were some Class 2 components which had the potential to leak onto Class 1 components that were routinely inspected. The licensee did not have documentation and was not positive that each component on the list of principal leak locations had, in fact, been inspected during each of the previous examinations.

9.1.2 Boric Acid Leakage Examination Schedule

The inspector found that the licensee had not established criteria for performing boric acid leakage examinations between refueling outages. The procedure stated that the, "examinations should normally be performed during scheduled refueling outages; however, additional examinations may be performed at any time." The inspector noted that the mode change procedures contained prerequisites to contact inservice inspection (ISI) engineering to determine the need for conducting a visual examination for leakage. The ISI supervisor

informed the inspector that several factors were considered when determining the need for conducting the exam including time since the last exam, amount of unidentified RCS leakage, and containment atmosphere activity; however, the supervisor could not provide specific criteria for any of the factors. These factors were not included in any procedure.

The inspector also noted that the licensee elected to not perform a GL 88-05 inspection during the current outage in Unit 2. The licensee stated that, in general, if the previous inspection had been conducted more than six months prior a "formal" GL 88-05 inspection would be performed.

9.1.3 Observation of a Visual Examinations

The inspector observed an ISI engineer demonstrate the GL visual examination during a tour of the Unit 2 containment area during midcycle Outage 2M5. The inspector observed the engineer inspect piping runs, instrument lines, insulation, and other components, and did not limit the inspection to boric acid containing components. Additionally, the inspector noted that for one component, the engineer had to make a determination of boric acid leakage from about 40 feet away without any special viewing instruments. The engineer concluded that the valve had an active leak and that carbon steel was affected by the boric acid. The inspector considered that this was a conservative call but could not determine if the call was accurate.

The engineer brought along small scale (large area) drawings that had circled numbers which apparently represented the principal leak locations. The inspector noted that the drawings were not referenced by procedure and were not controlled documents.

During the partial walkdown of the containment, the inspector and engineer identified eight components with active and inactive boric acid leaks that had not been previously identified during the outage. The inspector concluded that while none of the leaks appeared to have affected the components' integrity, the licensee was not scheduled to perform a GL 88-05 examination and may not have identified these problems.

9.1.4 Review of Past Visual Examinations

The inspector reviewed a sample of the pressure test reports used to document the past examinations. These reports were included as part of an EER on the component condition. The pressure test reports documented component deficiency, whether the leak was active or dry, whether the component contained boric acid, and whether carbon steel was affected. The EER provided an evaluation of the component and directed the disposition. The inspector noted that while the EER provided an evaluation for most of the components on the pressure test report, that there were inconsistencies in the level of evaluation.

The inspector noted that the EER which contained the last Unit 2 GL 88-05 inspection, the pressure test report indicated that the letdown heat exchanger

Valve (2PRCEV061) had an inactive leak and that carbon steel was not affected. The inspector reviewed the WO under which the valve should have been repaired during the previous outage and noted that this valve and two others in the WO were annotated as "could not locate." Neither the WO nor the EER provided justification for not repairing the deficiency during the outage. The licensee initiated an evaluation and concluded that the maintenance craft performing the repairs had contacted engineering and that engineering had appropriately evaluated the situation but that the justification had not been included in the WO. The inspector concluded that the WO had not been properly annotated and that the reviewers had not identified the deficiency. Additionally, the inspector concluded that the EER should have included a justification for delaying corrective actions.

9.1.5 Conclusions

The inspector concluded that the licensee's program for preventing boric acid corrosion of reactor coolant pressure boundary components was weak for the following reasons: it was poorly documented and, as a result, relied heavily on the skill of the ISI engineers to implement; it was limited to only ASME Section XI Class 1 components; it did not provide guidance on when the examination would be performed (other than every refueling outage); and it did not provide documentation that principal leak locations were inspected. The inspector concluded that the licensee's procedure did not incorporate the list of potential leak locations per the licensee commitments stated in the letter to the NRC dated May 27, 1988. This is a deviation of GL 88-05 commitments (Deviation 528/9431-07).

In response to these findings, the licensee stated that program revisions would be made to address these issues for the next refueling outage in Unit 2.

9.2 <u>(Closed) Violation 529/9423-01: Maintenance on Wrong Train Valve</u>

This violation involved technicians conducting work on a safety-related relay in the wrong train of equipment. As a result, a containment spray isolation valve opened allowing approximately 7000 gallons of water to gravity flow from the RWT into the containment.

The licensee determined that the root cause of the event was a cognitive, personnel performance error due to the lack of self-checking, poor communication, and poor teamwork among the maintenance and operations team members. Additionally, management weaknesses were identified in establishing consistent expectations for communication across the organization and for the use of the Sensitive Issues Manual.

The licensee initiated several immediate corrective actions as a result of this event that were discussed in NRC Inspection Report 50-529/94-23. Additional corrective actions included:

- The requirement to include an equipment verification step in work instructions was reevaluated and added back into the work instruction writer's guide.

- Cross-discipline communication standards were formalized using the previously existing operations communication standard as a guide.

The inspector verified during routine maintenance observations that the equipment verification step was included in the WO and was being performed by the technicians. The inspector also noted that the licensee was conducting a site status meeting to help improve communications and control of work activities. The inspector attended several of these meetings and has noted improved management oversight of critical work activities.

The licensee also had an independent analysis performed to determine if the redesigning of work processes (reengineering) had contributed to the event. The examination concluded that the redesigned process, if followed, would result in fewer wrong train events than the previous process, and that some important requirements present in both the redesigned and previous processes were bypassed. Based on this analysis, the licensee concluded that the redesigned process has sufficient safeguards in place to ensure there is appropriate control of work. The inspector concluded that the licensee has strengthened the performance issues that led to this event.

9.3 Essential Chiller (EC) Maintenance - Unit 3

The inspector reviewed CRDR 9-4-0273 that was written to evaluate the operability of Train B EC after maintenance in March 1994. The EC is a safety-related system that provides chilled water to ensure cooling of essential equipment required to operate during a design basis event. In the CRDR, the licensee evaluated three separate concerns with the performance of the maintenance: (1) the refrigerant side of the chiller was exposed to moisture in the air and was not subsequently evacuated as stated in the WO, (2) scheduling pressures may have contributed to the decision to not perform the evacuation, and (3) the motor terminal adapter fasteners may have been over-torqued.

9.3.1 Evacuation of Refrigerant

After maintenance on the EC to identify and repairs some refrigerant leaks around the motor terminal adapters, the WO had a step to evacuate the refrigerant. During this maintenance, the "C" phase terminal adapter was removed and the motor terminal was reinstalled without the packing or o-ring on the terminal board. This created a condition where the refrigerant side of the chiller was exposed to moisture in the air for a period of about four days.

The inspector noted that the step to perform the evacuation was marked "NA" (not applicable) by the technicians. The inspector reviewed the conduct of

maintenance procedure and noted that the workers are allowed to "NA" steps with appropriate justification. Prior to completing the maintenance, the foreman and technician made the decision that the evacuation was not necessary based on their experience with the chillers. However, the justification for not performing the evacuation was not documented in the WO until after the work was completed. The inspector concluded that although the workers met the minimum requirements of the conduct of maintenance procedure, the reason for not performing the evacuation was not thoroughly communicated, evaluated, and documented prior to completing the work. Additionally, the system engineer was not involved in the decision. The inspector was concerned because similar examples had been identified where WO steps were not completed without adequate justification (NRC Inspection Report 50-528/94-26, Section 4.3). At the exit meeting the Maintenance Director agreed with the inspector's concern and stated that he planned to address management expectations for deleting WO instructions during scheduled maintenance department briefings.

The inspector discussed the consequences of not performing the evacuation with the system engineer. The system engineer concluded that the existing condition would not adversely affect the operation of the EC. This conclusion was based on the fact that existing refrigerant pressure would have prevented large quantities of air from entering the system. Any moisture that may have entered the system would have been in the air and this amount of moisture was not significant compared to the size of the system. During the CRDR evaluation, an oil sample was taken which verified there was no moisture in the system. The inspector agreed with the licensee's conclusion that the chiller was operable.

9.3.2 Scheduling Impact

The inspector was concerned that the decision not to perform the evacuation of the chiller was inappropriately biased by scheduling pressures to finish the Train B work. Performing the evacuation would have delayed the Train B outage by as much as one day and would have required additional expenses to properly dispose of the refrigerant. The licensee determined that although the evacuation of the chiller following maintenance was a good work practice, the benefit of the evacuation in this case was minimal. The inspector also noted that the licensee surveyed the entire maintenance organization concerning whether they thought the most important part of their jobs was to meet the work schedule or to complete the job safely and correctly. The survey indicated that although completing the job on schedule was important, workers placed a greater emphasis on completing the job safely. Based on this information, the inspector concluded that the decision to not perform the evacuation was not inappropriately influenced by scheduling pressures.

9.3.3 Motor Terminal Adapter Torque

The WO specified to install the new motor adapter, including a step to torque the terminal adapter fasteners to torque values specified in a referenced document. The WO indicated that the new terminal adapter was installed and properly torqued. During the retest, a leak was found and the adapter was

removed, inspected, cleaned, and reconnected. The licensee determined, during their evaluation conducted in CRDR 9-4-0273, that the adapter fasteners were subsequently tightened using mechanical judgment rather than the required torque values.

Since there was a potential that the motor terminal adapter fasteners were over-torqued, the licensee initiated a separate WO to loosen the fasteners and tighten them to the proper torque values.

The inspector reviewed the original WO and noted that there was not a step referring the technicians to the instructions to torque the fasteners. The inspector noted that the licensee had not identified that the omission of this step contributed to the failure of the technicians to properly torque the fastener and had not initiated corrective actions to address the work instruction.

The inspector concluded that not properly torquing the adapter fasteners is a violation for failing to follow the WO instructions (Violation 530/9431-08). This violation is being cited since the licensee had not identified in their own investigation that the weakness in the WO was a significant contributor to the failure to follow procedure.

The inspector had previously noted several examples of poorly written WOs (NRC Inspection Reports 50-528/93-12, 50-529/93-12, 50-530/93-12, Section 6; 50-528/93-35, 50-529/93-35, 50-530/93-35, Section 14; 50-528/93-40, 50-529/93-40, 50-35-/93-40, Section 15.c; and 50-528/94-26, 50-529/94-26, 50-530/94-26, Section 4.3). At the exit meeting, the inspector expressed concern that WOs did not consistently provide the proper level of detail to help the technicians complete the work correctly. The Director of Maintenance acknowledged this weakness.

9.4 Changes to Previous Commitments - Units 1, 2, and 3

The licensee reviewed the conduct of maintenance and work control procedures and discovered that these procedures had requirements that were the result of commitments made to the NRC during a period from 1985 to 1989. The licensee conducted an evaluation and concluded that five of these commitments no longer implemented a valid requirement nor provided a significant barrier to prevent recurrence of the event or condition. On July 26, the licensee sent a letter to the NRC explaining that these commitments would no longer be actively tracked as part of the licensee's corrective action tracking system. The inspector reviewed the licensee's letter, discussed the process of reviewing the commitments with the responsible evaluator, and reviewed the initial NRC concern to ensure the licensee's current controls were adequate.

In the discussions with the licensee, the inspector determined that if a commitment is active it will be listed in the front of the procedure and the steps where the commitment applies will be specifically marked. If a commitment is deactivated, it will not be listed in the procedure and the

applicable steps of the procedure may be changed using the normal procedure review process.

The inspector noted that these particular commitments appeared to be necessary when they were discovered to ensure that standard management expectations were documented. For example, one commitment was made in 1987 to develop an administrative control procedure which provided guidance for preparation of online outages and ensuring that only one train of equipment was removed from service at a time. The inspector noted that the licensee had several barriers in the work control and work scheduling processes, and had effectively communicated management's expectation that train related work be properly scheduled, which should ensure that only one train of equipment was removed from service at a time.

During a review of the work control and modification processes, the licensee also identified about 40 other one-time commitments that were still active. These commitments involved reviewing Information Notices, providing procedures for NRC review, conducting crew briefings or other one time actions required as part of inspection report open items. The licensee closed all these actions using a memo to file. The inspector concluded that the licensee's actions to review and delete old commitments were appropriate.

ATTACHMENT 1

1 Persons Contacted

1.1 Arizona Public Service Company

J. Bailey, Vice President, Nuclear Engineering and Projects
L. Clyde, Department Leader, Outage Management
P. Crawley, Director, Nuclear Fuels Management
B. Eklund, Engineer, Nuclear Regulatory Affairs
A. Fakhar, Section Leader, System Engineering
B. Grabo, Section Leader Compliance, Nuclear Regulatory Affairs
W. Ide, Director, Operations
A. Krainik, Department Leader, Nuclear Regulatory Affairs
D. Lamontagne, Senior Licensing Engineer, Nuclear Regulatory Affairs
D. Larkin, Senior Engineer, Nuclear Regulatory Affairs
J. Levine, Vice President, Nuclear Production
D. Mauldin, Director, Site Maintenance and Modifications
W. Montefour, Senior Rep., Management Services
J. Scott, Director, Chemistry
W. Stewart, Executive Vice President, Nuclear

1.2 NRC Personnel

K. Johnston, Senior Resident Inspector
H. Freeman, Resident Inspector
J. Kramer, Resident Inspector
A. MacDougall, Resident Inspector

1.3 Others

J. Draper, Site Representative, Southern California Edison
R. Henry, Site Representative, Salt River Project

All personnel listed above attended the Exit meeting held on October 25, 1994.

2 EXIT MEETING

An exit meeting was conducted on October 25, 1994. During this meeting, the inspectors summarized the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

AO	auxiliary operator
CRDR	Condition Report/Disposition Request
CRS	control room supervisor
CST	condensate storage tank
EC	essential chiller
EDG	emergency diesel generator
EER	engineering evaluation report
FME	foreign material exclusion
GL 88-05	Generic Letter 88-05
ICV	individual cell voltages
ISI	inservice inspection
LCO	limiting condition for operations
LI	level indicator
LLRT	local leak rate test
LOCA	loss of coolant accident
NAFW	non-class auxiliary feedwater pump
NR	narrow range
OOC	out of calibration
RCS	reactor coolant system
RO	reactor operator
RP	radiological protection
RSP	remote shutdown panel
RWT	refueling water tank
RWLIS	refueling water level indicating system
SS	Shift Supervisor
STA	Shift Technical Advisor
TS	Technical Specifications
WO	work order
WR	wide range