APPENDIX B

U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Inspection Report: 50-528/94-02
50-529/94-02
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Operating Licenses: NPF-41
NPF-51
NPF-74

Licensee: Arizona Public Service Company
P. O. Box 53999, Station 9082
Phoenix, AZ 85072-3999

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

Inspection At: Maricopa County, Arizona

Inspection Conducted: January 11 through February 14, 1994

Inspectors: K. Johnston, Senior Resident Inspector
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Approved By: H. J. Wong, Chief — 3/15/94 Date Signed
Reactor Projects Branch II

Inspection Summary:

Areas Inspected (Units 1, 2, and 3): Routine, announced, resident inspection of:

- Plant events (inspection procedure 93702)
- Plant activities and operational safety verifications (71707)
- Maintenance activities (62703)
- Surveillance activities - Units 1 and 2 (61726)
- Diesel Generator problems (61726, 62703, 71707)
- Steam generator inspection, chemical cleaning, and tube plugging (62700, 42700, 37703, 73753, 62703, 92701)
- Review of Employee Concerns Program (92720)

- Training and Qualification Effectiveness (41500)
- Follow-up on corrective actions for Violations (92702)
- Follow-up of previously identified items (92701)
- Follow-up of Licensee Event Reports (92700, 90712)

Results (Units 1, 2, and 3):

Strengths:

- Plant management responded swiftly to inspector-identified concerns regarding worker performance in the radiological controlled area (RCA). Comprehensive corrective actions were initiated following the initial notification of the issues to first-line supervisors (Sections 3.1 and 4.2).

- Unit 1 operations personnel thoroughly reviewed a plant protection system circuit problem, demonstrating a questioning attitude throughout the review (Section 5.2).

Weaknesses:

- A Unit 2 contract employee removed his security badge and dosimetry and placed it on a nearby transformer while working inside the protected area and within the RCA (Section 3.1). In addition, the inspectors found that plant personnel did not consistently display their security badges and dosimetry as required by plant procedures (Section 3.2).

- Maintenance personnel demonstrated poor radiological practices while working on a main turbine control valve (Section 4.2).

- The inspectors observed several examples of poor plant material condition and in several of these instances the deficiencies had not been previously identified by the licensee (Sections 3.3 and 6.5).

- Engineering was slow to evaluate the cause of cracks observed in the valve bodies of two Unit 2 containment isolation valves (Section 4.3).

- The removal from service of a emergency diesel generator jacket water system automatic valve without a documented review, despite the fact that its function was described in detail in the FSAR, indicated that the licensee's review of degraded plant conditions was weak (Section 6.4).

Summary of Inspection Findings:

- Violation 50-529/94-02-01 was identified (Section 3.1)

- Follow-up items 50-529/94-02-02 and 50-528/94-02-03 were opened (Section 3.3.1)

- Violations 50-529/93-04-02, 50-529/93-35-02, and 50-529/93-40-4 were closed (Section 10).
- Follow-up items 50-530/93-11-5 and 50-529/93-55-01 were closed (Section 11).
- Licensee event reports 50-530/93-03 (Section 12) and 50-528/93-04, revision 1 (Section 13), were closed.

Attachment: Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 operated throughout the inspection period at essentially 85% power. On January 17, 1994, Unit 1 experienced a 250 megawatt load shed due to the earthquake in southern California. The steam bypass control system responded to maintain plant power and all systems responded normally during the event.

On January 26, 1994, the licensee determined that three of the four atmospheric dump valve (ADV) linear variable differential transformers (LVDT) had been in-service longer than their qualified life. The licensee determined that the failure of the LVDT would not affect the operation of the ADV or prevent operators from determining the position of the ADV. The licensee documented their evaluation in a justification for continued operation. At the end of the inspection period, one of the three LVDTs had been replaced.

On February 7, 1994, the licensee detected small amounts of radioactive tritium in the secondary system. On February 8, 1994, the licensee installed anion resin paper in the Steam Generator No. 2 downcomer sample line and measured small amounts of radioactive iodine which confirmed a very small primary-to-secondary leak. Based on the tritium levels in the steam generators, the leak rate was less than 1 gallon per day (GPD). At the end of the inspection period, the licensee was closely monitoring the tritium levels and the leak rate was staying constant at less than 1 GPD.

1.2 Unit 2

Unit 2 began the inspection period in Mode 5 starting a mid-cycle steam generator tube eddy current inspection and chemical cleaning outage. The licensee reduced the reactor coolant system level to mid-loop to facilitate the installation of steam generator nozzle dams in preparation for eddy current testing of the steam generator tubes. The RCS level was then raised to a level just below the reactor vessel flange and remained there throughout the inspection period. The licensee completed chemical cleaning of the steam generator during the outage (see Section 7.2). The licensee had completed steam generator eddy current testing of steam generator 2-1 and was continuing to test steam generator 2-2 at the end of the period (see Section 7.1). The licensee had identified a significant number of axial crack indications in steam generator 2-2.

1.3 Unit 3

Unit 3 operated throughout the inspection period at essentially 85 percent power. On January 19, 1994, the licensee gagged closed a steam generator safety valve which had developed a small seat leak. Gagging one safety valve reduced the Technical Specification maximum allowable reactor power to 98.2 percent.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Main Steam Isolation Valve Fast Closure - Unit 1

On January 20, 1994, during a surveillance test to partial stroke the Main Steam Isolation Valves (MSIV), MSIV-170 fast-stroked full closed and immediately fast-stroked full open. The plant responded as follows:

- Reactor coolant temperature increased about one degree.
- Primary system pressure did not change.
- The affected steam generator pressure increased about 20 psig.

The licensee declared the "A" train of the hydraulic system for MSIV-170 inoperable. MSIV-170 remained operable since the "B" train of the hydraulic system was still available to operate the valve. The licensee determined the cause of the event was a failure of the "C" solenoid valve in the "A" train. This aligned hydraulic accumulator, instead of the hydraulic pump, to the MSIV operator and fast-closed the valve. The solenoid valve was replaced and a partial stroke test was satisfactorily completed.

The inspector reviewed the licensee's troubleshooting of MSIV-170 and concluded that the licensee's response to this event was appropriate.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The inspectors performed this inspection to ensure that the licensee operated the facility safely and in conformance with license and regulatory requirements and that the licensee's management control systems effectively discharged the licensee's responsibilities for safe operation.

The methods used to perform this inspection included direct observation of activities and equipment, observation of control room operations, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and Technical Specifications limiting conditions for operation, verification of corrective actions, and review of facility records.

3.1 Worker Removed Dosimetry and Security Badge in Radiological Controls Area/Protected Area - Unit 2

On January 25, 1994, the inspector noted that an individual was working inside the protected area and within the radiological controlled area (RCA) and was not wearing his automated controlled access device (ACAD) or dosimetry. The individual was a contract worker involved in steam generator chemical cleaning operations (see Section 7.1). The inspector observed that the ACAD and dosimetry was on top of a nearby transformer, approximately five feet from the worker. When the worker noticed the inspector looking at the ACAD and dosimetry on the transformer, he properly attached it to his body. The worker was working in the pump trailer used for steam generator chemical cleaning. The radiation levels in the trailer were subject to change due to various chemical solutions being pumped through the trailer. The inspector notified

the worker's supervisor of this observation. The supervisor subsequently informed radiation protection (RP) and security.

Procedure 75AC-9RP01, Revision 2, "Radiation Exposure and Access Control," Step 3.2.3, states, in part, that personnel will be issued dosimetry which shall be worn at all times within the RCA. Step 3.2.4.1 states, in part, that dosimetry shall normally be worn on the front of the body between the thigh and head, unless directed otherwise by RP. Procedure 20AC-0SK04, Revision 9, "Protected/Vital Area Personnel Access Control," Step 3.2.1, states, in part, that ACADs shall be displayed by all individuals while inside Protected/Vital areas and shall be positioned on the front of the outermost garment, between the neck and the waist, photograph side out. The failure of the employee to follow procedures is a violation of Technical Specification 6.8.1 (Violation 50-529/94-02-01).

The licensee initiated Condition Report/Disposition Request (CRDR) 2-4-0041 to evaluate this problem. The licensee also performed an exposure evaluation of the worker. The worker's TLD was read and the area he had worked in was surveyed. Based on the survey, a maximum unmonitored exposure of 0.003 mrem could have been received by worker. The RP Department denied the employee further access to the RCA. In addition, the Security Department performed a check to verify that unauthorized use of the worker's ACAD had not occurred and that the ACAD had not left the worker's sight. The Security Department also removed the employee's unescorted access to the protected area. Further, the contractor for chemical cleaning held training for all of its employees to re-emphasize the licensee's expectations in security, radiation protection, and job performance.

The inspector noted that the licensee's response to this event was thorough. In particular, the inspector noted that the licensee took prompt action to assess the incident and took action when it was brought to the attention of first line supervision by the inspector.

3.2 Dosimetry/Security Badge Placement

On February 7, 1994, the inspector observed a licensee maintenance individual entering the Unit 3 radiologically controlled area (RCA) wearing the dosimetry/security badge (i.e., ACAD) hanging off the right front pant's pocket. The dosimetry at Palo Verde is attached to the security badge. The individual moved the badge to the torso after the inspector questioned a radiation protection technician whether this was the correct location for the dosimetry. Later, the inspector noted that there were other personnel wearing their dosimetry in similar locations inside the RCA.

As noted in Section 3.1 of this report, the licensee procedures required that dosimetry shall normally be worn on the front of the body between the thigh and head unless otherwise specified by Radiation Protection (RP). The licensee's procedure for personnel access control required that the security badge be displayed on the front of the outermost garment, between the neck and the waist. Additionally, the procedure required that all personnel report any unbadged personnel in the protected/vital area. Although the badge location probably did not affect the measured whole body dose reading in these cases,

the inspector noted that the improper location of the badge could hamper proper identification by security.

The licensee acknowledged the problem and committed to have all managers and supervisors review with their employees the proper location for the dosimetry and security badge. Additionally, the licensee noted that they would review the differences in the requirements for security badge placement and dosimetry placement to determine if a change was needed. Finally, the licensee committed to review employee training/retraining to determine if the location was properly defined. The inspector considered these corrective actions to be adequate.

3.3 Plant Material Condition

3.3.1 Unit 2 High Pressure Safety Injection Pump (HPSI)

During a routine plant tour, the inspector observed that large boric acid formations had formed at both ends of the HPSI 2A pump. The acid formation was apparently due to pump seal leakage. The licensee responded by issuing a work order and had the pump cleaned. The licensee stated that the seals were scheduled for replacement in the next refueling outage and every subsequent third refueling outage.

The inspector reviewed the Updated Final Safety Analysis Report (UFSAR) and determined that Section 6.3.1.3.N.1.a states, in part, that the maximum HPSI pump seal leakage allowed is 100 cc/hr. Although unable to determine the extent of the pump seal leakage since the HPSI pump was in standby mode, the inspector noted that the licensee had performed the Technical Specification surveillance inspection of emergency core cooling system (ECCS) leakage (TS 4.4.5.2.1) during the refueling outage in August 1993. The purpose of this test was to verify that there was less than 1 gallon per minute leakage of the ECCS equipment outside containment providing long-term, post loss-of-coolant-accident recirculation. The seals had no identified leakage during the performance of this test.

Based on the observation of a number of other boric acid leaks in ECCS pumps and valves and the fact that the licensee did not attempt to quantify leaks as they developed, the inspector questioned the basis of the UFSAR pump seal leakage requirement and whether the TS surveillance was adequate to verify compliance with the requirement. The inspector will review the licensee's response to these questions during a future inspection (Followup item 50-529/94-02-02).

3.3.2 Unit 1 Walkdown

During a routine tour of Unit 1, the inspector identified a small steam leak from a drain valve in the supply line to the steam-driven, auxiliary feedwater pump and packing leaks from both condensate transfer pumps. The inspector reported these conditions to the shift supervisor who was not aware of the deficiencies. Unit 1 mechanical maintenance personnel evaluated the conditions and determined that the steam leak was unisolable and that a leak repair had been previously attempted. A new work order was written to attempt

another leak repair. The inspector noted that a work order had been previously written to adjust the packing on one of the condensate transfer pumps. However, the other packing leak had not been identified and a work order was written to repack the pump. At the end of the inspection period, the packing was replaced and the steam leak and packing adjustment on the other pump were included in the 12-week work schedule.

3.3.3 Conclusions

In addition to the conditions discussed in the above sections, the inspectors noted several other minor material condition problems during routine walkdowns, such as boric acid leaks in pump and valve packings and lube oil leaks on pump bearings. Upon followup, the inspectors found that several of these conditions had not been previously identified by the licensee. The inspectors noted that the licensee does not require that maintenance tags be placed on equipment when a maintenance request has been initiated. As a result, it is not obvious to plant personnel who observe plant deficiencies whether a deficiency has been previously identified. Because of this, personnel would need to verify whether the deficiency had already been identified and, if not, initiate documentation of the problem. The additional verification work could be an obstacle for plant personnel to identify new plant problems.

The inspectors discussed these observations at the exit meeting. The licensee management noted that significant efforts had been made in the 1990 - 1991 time frame to improve the plant's material condition. Nevertheless, they conceded that progress may have slowed and committed to review their plant material condition program.

4 MAINTENANCE OBSERVATIONS (62703)

During the inspection period, the inspectors observed and reviewed the selected maintenance and activities listed below to verify compliance with regulatory requirements and licensee procedures, required quality control department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, appropriate radiation worker practices, calibrated test instruments, and proper post-maintenance testing. Specifically, the inspectors witnessed portions of the following maintenance activities:

4.1 Atmospheric Dump Valve Positioners - Unit 1

On February 3, 1994, the inspector observed the calibration of the air positioner for atmospheric dump valve (ADV) 178. The inspector reviewed the maintenance procedure, discussed the history of ADV maintenance problems with the system engineer, and noted the steps operators took to declare ADV-178 operable following maintenance.

The inspector noted that the licensee has had several problems with early failures of the ADV positioners since 1992. Plant engineering conducted a thorough evaluation of positioner failures in 1992 and 1993. These evaluations provided sound recommendations to improve the reliability of the

positioner. The inspector also noted that the ADV calibration procedure incorporated vendor recommendations and adequately demonstrated the performance of the new positioner. However, surveillance test (ST) 41ST-1SG05, "ADV Nitrogen Accumulator Drop Test," has not been consistently performed as a retest to ensure operability of the ADV.

4.1.1 History of Positioner Maintenance

On January 3, 1994, operators performed a nitrogen system pressure drop test on ADV-178. The positioner leak rate was measured at 0.9 standard cubic feet per minute (scfm). This was higher than the normal leak rate of 0.6 scfm (some amount of leakage through the positioner is required for the positioner to function). The licensee determined that if the positioner leakage increased to about 1.0 scfm, the overall nitrogen system would probably not meet the pressure drop test requirements. On January 21 the licensee replaced the positioner and performed successful pressure drop and functional tests.

On January 30, operators performed a functional test of ADV-178 and discovered that it failed the 30 percent open response time requirements. The licensee determined that ADV-178 failed this test due to excessive positioner leakage. CRDR 1-4-0038 was written to determine the cause of the January 30 failure of the positioner.

On February 3, the licensee replaced the positioner for ADV-178 with a newer model. The manufacturer redesigned the internals of the positioner to provide more surface area to "grip" the diaphragm. The positioner for ADV-178 was the first of 12 ADV positioners on-site to be replaced with the newer model. The licensee planned to replace the older style positioners with the new models when they fail or when they reach the end of their qualified life.

4.1.2 Performance of Appropriate Retest

On February 3, the shift supervisor declared ADV-178 operable after the technicians successfully completed the positioner calibration. During the final review of the work order, the shift supervisor recognized that surveillance test 41ST-1SG05, "ADV Nitrogen Accumulator Drop Test," should have been performed prior to declaring ADV-178 operable. The drop test had not been listed in the retest portion of the work package. The drop test was immediately performed and satisfactorily completed.

The licensee determined that 41ST-1SG05 was not consistently used as a retest to ensure operability of the ADV. At the conclusion of the inspection, the licensee was conducting a review to determine whether the retest was required and the significance of not performing the test. CRDR 1-4-044 was initiated to evaluate the condition. The inspector will review the results of the CRDR in a future inspection report (Followup item 50-528/94-02-03).

4.2 Main Turbine Control Valve (CV-3) Assembly and Restoration - Unit 2

On February 4, 1994, the inspector observed contract maintenance employees performing work on a main turbine control valve. Portions of the Unit 2 secondary systems were being controlled as radiologically contaminated areas

as a result of the 1993 steam generator tube rupture event. The inspector noted the following weaknesses in the worker's radiation protection practices:

- Upon the inspector arrival in the work area, the foreman reached across the radiological controlled area (RCA) boundary and offered to shake the hand of the inspector. The inspector verified that the foreman had been instructed during general employee training that reaching across an RCA boundary was not an acceptable radiological practice.

- An employee, while working in a radiologically contaminated area, retrieved a tool that had been dropped across the contaminated boundary without ensuring that radiation protection (RP) had been notified and without ensuring that radiological conditions had not changed. Coincidentally, an RP technician, who had just arrived at the job site, observed the workers retrieve the tool. The technician surveyed the area where the tool had been and determined that there had been no spread of contamination.

The inspector brought these observations to the attention of the a Unit 2 maintenance foreman. In response, the licensee held a stand-down meeting on February 7, with all site mechanical personnel assigned to the turbine deck. The briefing included a representative from RP who discussed radiological work rules and how to treat radiation boundaries. In addition, licensee management detailed their expectations regarding radiological work practices. A second stand-down and briefing was held for the remainder of the crew that came of shift on February 9. Additionally, the licensee planned to conduct detailed, pre-job briefings prior to performing activities inside contaminated areas or when work activities require personnel to be on both sides of radiological boundaries.

The inspector noted that the increased attention given to radiological work practices on the turbine deck and concluded that the licensee's corrective actions were appropriate.

4.3 Reactor Coolant System Sample Line Isolation Valves With Internal Cracks - Unit 2

On January 27, 1994, Unit 2 maintenance workers identified cracking in the valve bodies of two reactor coolant system (RCS) sample line valves. The two valves, SSAUV-203 and SSBUV-200, were the containment isolation valves for the RCS loop 1 hot leg sample line. Maintenance workers had been inspecting the valves to determine the cause of seat leakage. The cracks were internal to the valve body and circumscribed the seat area. However, it did not appear that the cracking could have caused the seat leakage.

The licensee determined that there were a total of six containment isolation valves in each unit which are similarly-designed and in similar service conditions. The licensee visually inspected the inside of a third Unit 2 valve and did not observe cracks. A licensee review of the past maintenance history on these eighteen valves and the industry history, did not identify other examples of cracking problems.

The licensee developed an action plan to (1) remove SSAUV-203 and send it to a laboratory for fracture mode analysis; (2) remove SSBUV-200 and conduct on-site ultrasonic testing (UT); and, (3) cut SSBUV-200 into quarters and perform visual and microscopic examinations following the ultrasonic testing. The licensee initially planned to UT the 15 valves that had not been visually inspected. However, when they performed the UT of SSBUV-200, they were not able to characterize the extent of the cracking. As a result, they determined that UT of the remaining 15 valves would not provide useful information.

By February 14, SSAUV-203 had not been delivered for inspection to the independent laboratory. The licensee had decided not to perform destructive examination of SSBUV-200 until the other valve had been delivered. As a result, the cause of the cracking had not been determined. The inspector noted at the exit meeting that while the initial action plan was well developed, the progress of this investigation had been slow. Licensee management concurred with this assessment and noted that the valve had subsequently been delivered and that they expected a more timely resolution of the issue.

5 SURVEILLANCE OBSERVATION (61726)

The inspectors reviewed this area to ascertain that the licensee conducts surveillance of safety-significant systems and components in accordance with Technical Specifications and approved procedures.

5.1 Reactor Protection System (RPS) Response Time Testing - Unit 2.

On February 3, 1994, the inspector observed portions of surveillance test (ST) 36ST-9SB44, "RPS Matrix Relays to Reactor Trip Response Time Testing," in Unit 2. For most of the plant protection system (PPS) instruments, Technical Specification (TS) 3.3.1 requires that the total channel response time to be less than 1.15 seconds. TS 4.3.1.3 also requires that one channel of each function be tested at least once every 18 months.

The total response time is measured in the following three steps:

- Procedure 36ST-9SB41 measured the process equipment response time [i.e., the time from the process transmitter (e.g. pressurizer pressure) to the PPS cabinet].

- Procedure 36ST-9SB42 measured the PPS cabinet response time (i.e., the time from the PPS cabinet to the matrix relays).

- Procedure 36ST-9SB44 measured the response time from the matrix relays to the reactor trip breaker opening.

The inspector concluded that the these surveillance procedures adequately demonstrated that the overall response time requirements of TS 4.3.1.3 were satisfied. Additionally, the inspector noted that procedure 36ST-9SB44 was well written and that the technicians used good communications during the performance of 36ST-9SB44.

The inspector reviewed the data collected during the performance of 36ST-9SB41 completed on March 26, 1993; 36ST-9SB42 completed on August 16, 1993; and during the inspector's observation of 36ST-9SB44 on February 3, 1994. In addition, the inspector reviewed calculation 13-JC-SB-02 to determine the basis for the acceptance criteria provided in these surveillance tests. The purpose of this review was to verify that the overall time response of the "B" channel high and low pressurizer pressure trips were within the TS requirement of 1.15 seconds.

Based on these reviews the inspector concluded that, the TS requirement to verify the "B" channel pressurizer pressure high and low trip response time was satisfied; the "B" channel was tested within the 18-month period specified in TS 4.3.1.3; the overall process response time was satisfied by meeting the acceptance criteria for each portion of the test; and the calculation for the acceptance criteria contained a large margin of safety and the actual response times were well within the TS requirement.

5.2 Plant Protection System Functional Test - Unit 1

On February 9, 1994, during the performance of surveillance test 36ST-9SB04, "Plant Protection System (PPS) Functional Test-Reactor Protection System/Engineered Safety Features Actuation System (ESFAS) Logic," the technicians identified a problem which they believed to be in the test circuit. The inspector observed that the technicians immediately notified the shift supervisor and documented the problem in the test log. The shift supervisor and shift technical advisor reviewed the test logic diagrams and agreed that the most likely cause of the problem was with the test circuit. However, the shift supervisor continued to question the technicians and contacted the I&C supervisor and system engineer to ensure a proper evaluation was performed. The system engineer also thought the problem was in the test logic portion of the circuit. The same step was repeated 5 times and the proper response was obtained. The remaining portions of 36ST-9SB04 were satisfactorily completed. The licensee initiated CRDR 1-4-0060 to trend the spurious test circuit anomaly.

The inspector concluded that the problem was appropriately documented and that the shift supervisor aggressively evaluated the problem to ensure that the performance of the RPS was not affected.

6 DIESEL GENERATOR CONDITION AND TESTING (61726, 62703, 71707)

During the inspection period, the licensee experienced unanticipated trips of an emergency diesel generator (EDG) in all three units. Each of the trips resulted from a non-safety related problem. In each case, the inspectors assessed the licensee's review and plans for corrective actions. In addition, this section discusses a degraded condition in the Unit 1 "B" EDG jacket water system that was not thoroughly evaluated by the licensee.

6.1 Unit 1 - Diesel Generator Reverse Power Trip During Shutdown Sequence

On January 25, 1994, a reverse power trip of the Unit 1 "B" EDG occurred while operators were securing the EDG per procedure 41OP-1DG02, "Emergency Diesel

Generator B." The EDG was running to perform the weekly Technical Specification surveillance test. The inspector concluded that the operator correctly followed the procedure for securing the EDG. Despite weaknesses in the procedure and a lack of sensitivity by the operator concerning the potential for a reverse power trip contributed to the event, the inspector concluded that the licensee's corrective actions were appropriate.

Procedure 410P-1DG02 directed the operator to lower the generator output to less than 0.1 megawatts (MW) and then open the generator output breaker. The operator lowered power to approximately 0.1 MW and turned to discuss the evolution with a trainee. When he turned to trip the output breaker, the wattmeter still indicated 0.1 MW and the EDG tripped automatically on reverse power.

The licensee inspected the "B" EDG output breaker and found no damage to the breaker or the generator. An evaluation of the event was conducted and documented in Condition Report/Disposition Request (CRDR) 1-4-0023. The licensee concluded that the following factors caused the reserve power condition:

- The operating procedure directs the EDG to be unloaded to 0.1 MW, but the megawatt meter is calibrated to only +/- 0.2 MW.
- Operators were not aware, and had not been trained, that the megawatt meter in the control room would show a positive indication in a reserve power condition.
- The operator delayed tripping the output breaker; however, there are no precautions in the procedure to ensure that the output breaker is immediately opened after the load is reduced to 0.1 MW

Unit 1 operations management issued a night order emphasizing the need to immediately trip the output breaker when the EDG is unloaded. The night order also discussed the expected response of the megawatt meter during a reverse power condition. In addition, an Instruction Change Request was initiated to change the EDG operating procedures in all three units to lower the generator output to 0.3 MW before opening the output breaker. The inspector concluded that these actions appeared to be appropriate.

6.2 Unit 2 - Diesel Generator Trips Due to Control Air System Problems

On January 30, 1994, the Unit 2 "B" EDG tripped after 10 seconds of the cooldown cycle of a surveillance test. The licensee reviewed the trip and determined that it resulted from the failure of a check valve in the pneumatic, non-safety related, control air system. The control air system provides protective trips to the EDG governor during maintenance runs; however, these trips are bypassed during a safety start. The licensee subsequently repaired the check valve.

On January 31, 1994, during the post-maintenance start of the "B" EDG, the fuel racks closed before the EDG reached rated speed, and the diesel

subsequently tripped on under-frequency. Although the problem appeared to be caused by the control air system, the licensee could not identify the component which caused the failure. It appeared that a control air system solenoid allowed the air to pass through to the fuel racks and close them. During an emergency run of the diesel, two emergency solenoids in series would have prevented the trip by preventing the fuel racks from closing.

The licensee restarted the EDG on February 1, 1994, with instrumentation installed for troubleshooting. However, the cause of the earlier trip was not determined. The licensee determined that a diesel start failure, as defined in the Technical Specifications, had not occurred since the diesel would have started if required during an emergency. The inspector agreed with the licensee and concluded that a start failure had not occurred during the January 31, 1994, start of the EDG.

6.3 Unit 3 - Diesel Generator Overspeed Trip During Shutdown Sequence

On January 26, 1994, the Unit 3 EDG "A" tripped on overspeed during a post maintenance retest. The diesel was being retested following planned maintenance and tripped immediately after the operator depressed the manual shutdown button. Depressing the manual shutdown button disengages the electrical governor and engine speed control is taken over by the mechanical governor. Engineering and maintenance troubleshooting determined that the mechanical governor had not controlled properly and that the problem was probably caused by air in the governor's hydraulic control lines. The oil in the governor had been changed previously as part of the planned maintenance. The licensee restarted the EDG, cycled the speed setting on the manual governor several times, and then performed a normal shutdown.

The inspector compared the procedure for changing the governor oil with the vendor technical manual. The inspector concluded that the technical manual did not specify how to change the governor oil to ensure that the hydraulic lines were not air bound. The licensee informed the inspector that they intended to incorporate the cycling of the mechanical governor speed control into the oil change procedure to prevent future problems with the governor. The inspector concluded that this action was appropriate.

6.4 Unit 1 - Diesel Generator Jacket Water Expansion Tank Automatic Make-up Capability Disabled Without Appropriate Review

During a system walkdown of the Unit 1 "B" EDG, the inspector noted that the jacket water make-up combined-header stop valve, 1PDGBV013, was shut. There was a caution tag on the valve indicating that the valve was closed due to leakage past the solenoid-operated, auto make-up valve. With the jacket water make-up valve closed, the jacket water expansion tank level could not be controlled automatically. The ability to automatically control level was described in the Updated Final Safety Analysis Report (UFSAR).

The inspector reviewed the licensee's work control processes to determine whether the licensee had conducted an operability evaluation of this condition. The inspector found that the licensee had not considered the automatic function described in the UFSAR. In addition, the licensee's

screening process for conducting operability evaluations of degraded conditions was narrowly focused and did not include conditions where automatic functions described in the current licensing basis were removed.

The inspector was concerned that the failure to include an evaluation of the removal of automatic functions in the operability screen process was a significant weakness, in that safety significant design changes to the plant could be inadvertently performed without an appropriate operability evaluation. As discussed in Generic Letter 91-18, which distributed NRC Inspection Manual 9900, "Operability", it is important to evaluate the physical differences between the automatic and manual actions to ensure the change does not alter the licensing basis for the plant. Nevertheless, the inspector considered that the safety significance of this particular condition was low because the EDG automatic jacket water make-up function was designed as an operator convenience and was not needed to ensure the proper operation of the EDG.

6.4.1 Degraded/Nonconforming Condition

The inspector determined that the leaking jacket water auto make-up valve was a degraded condition and reviewed the licensee's program requirements for degraded conditions described in procedure 02PR-0QQ01, "Control of Degraded and Nonconforming Material." This document stated that a work request (WR) or Condition Report/Disposition Request (CRDR) should be used to report a degraded condition. The inspector noted that WR 862611 was written on December 10, 1993, which was the same date that the auto make-up valve was found leaking and caution tagged. The WR was subsequently canceled on December 15, 1993, by the work planner. The work planner had initiated CRDR 1-3-0208 in March 1993 based on repeated problems with the make-up valve leaking. The planner decided to defer the maintenance and leave the jacket water auto make-up valve isolated until engineering completed this evaluation (the action was due in April 1994). The inspector concluded that the degraded condition of the auto make-up valve was appropriately reported and documented.

6.4.2 Operability Evaluation

The inspector noted that Appendix D to procedure 30DP-9WP01 "Work Initiation," contained a potential impact screening step used to determine if a WR required additional review by the shift supervisor. Although the impact screening for the jacket water auto make-up valve WR was conducted by an operations evaluator and was not forwarded to the shift supervisor for an operability determination, the inspector concluded that the operability decision was consistent with the screening criteria.

The inspector further concluded that the guidelines for screening WRs for operability concerns were narrow. The guidelines addressed only those situations where Technical Specifications (TS) and associated Limiting Conditions for Operations (LCOs) were obviously impacted by a degraded condition. In the case of the auto make-up valve, the evaluator decided that the loss of the automatic make-up capability for the jacket water expansion tank did not impact the operability of the EDG. This decision was apparently

based on isolating the jacket water auto make-up valve in the past due to similar problems with the valve leaking.

The inspector discussed the design basis for the auto make-up capability with the system engineers. In July 1993, during the evaluation of CRDR 1-3-0208, the system engineer documented that the function of the automatic jacket water make-up system was for operator convenience and not for design safety or to minimize the impact of any postulated jacket water system failures. When the auto make-up valve was shut in December 1993, the operations evaluator was not aware of the function of the valve described in the CRDR evaluation. The inspector concluded that removing the automatic jacket water make-up system did not adversely affect the operation of the EDG.

6.4.3 Licensee Actions

The inspector discussed the weaknesses in the operability guidelines with licensee management. The licensee had formed a review group to develop more comprehensive guidelines for operability determinations based on previous NRC concerns (see NRC Inspection Report 50-528/93-12, Paragraphs 13 and 17.b.). At the exit meeting, licensee management recognized that this issue demonstrated a vulnerability in their degraded condition review process and indicated that the lessons learned would be factored into their operability determination guideline development. The inspector will continue to follow the licensee's progress in this area during routine inspection.

6.5 Conclusions

At the exit meeting, the inspector noted that while the problems resulting in unanticipated EDG trips and the degraded condition of the jacket water system in Unit 1 did not appear to be safety significant, they may be precursors of degrading EDG condition. In addition, the inspector noted that each of the EDGs appeared to have numerous minor lube oil, fuel oil, and air system leaks. The inspector recognized a licensee management initiative to assess the EDG trips to determine if there were common problems which could affect EDG reliability. Licensee management noted that in recent years there had been increased emphasis in reducing EDG out-of-service times. This may have raised the threshold for correcting minor system problems. They stated that an assessment of EDG maintenance practices and their affect of EDG reliability would be performed.

7 STEAM GENERATOR INSPECTION, CLEANING AND PLUGGING

7.1 Steam Generator Eddy Current Testing (73753)

7.1.1 Background and Purpose

During this inspection, the licensee conducted extensive eddy current inspections of the Unit 2 steam generators. The licensee's inspections were being performed to comply with commitments made in their letter to the NRC, dated July 18, 1993. The purpose of this inspection was to determine if the licensee and licensee contractors had been performing inspections, data

analysis, and inspection scope changes in accordance with licensee procedures and commitments.

7.1.2 Procedures

The inspector reviewed licensee procedure 73TI-9RC01, "Steam Generator Eddy Current Examinations," Revision 10, dated January 12, 1994. The procedure was reviewed to determine if requirements for bobbin coil and motorized-rotating pancake coil (MRPC) eddy current data analysis and evaluation had been defined. The inspector reviewed the procedure to assess the licensee's criteria for equipment calibration and bobbin coil and MRPC data discrepancy resolution. The procedure was also reviewed to determine if the flaw indications, which were expected by the licensee in certain areas of the steam generator, had been identified.

The inspector found that specific requirements for bobbin coil and motorized-rotating pancake coil eddy current data analysis and discrepancy resolution had been adequately defined in the procedure. The inspector also found that equipment calibration and particular types of flaw indications for each section of each steam generator area had been adequately defined in the procedure.

The inspector concluded that licensee procedure 73TI-9RC01 included requirements for bobbin coil and motorized-rotating pancake coil (MRPC) eddy current data analysis and evaluation. The inspector concluded that the procedure also included equipment calibration criteria, bobbin coil and MRPC data discrepancy resolution criteria, and descriptions of particular flaw indications expected to be found in certain areas of the steam generator tubes.

7.1.4 Observations

Data Analysis

The inspector observed licensee activities at four MRPC and two bobbin coil data acquisition stations to determine if the licensee had been performing and recording data in accordance with licensee procedures. The inspector also reviewed eddy current test equipment calibration records. The inspector found that the licensee had been performing the bobbin coil and MRPC eddy current steam generator tube examinations in accordance with licensee procedure. The inspector also found that the licensee had been recording data on approved data sheets and that eddy current inspection equipment calibrations had been performed and were being checked in accordance with procedure.

The inspector also observed activities at four data analysis stations. The inspector found that each of the four stations had a current technique sheet. The inspector noted that the eddy current operator was utilizing frequencies and mixes specified on the technique sheet for eddy current testing analysis in accordance with procedure 73TI-9RC01. Therefore, the inspector concluded that licensee personnel had been performing steam generator tube eddy current inspections, data recording, and data analysis in accordance with licensee procedures.

Calibration

On January 31, 1994, during the licensee's QA review of eddy current testing work, the licensee identified that 4 of 36 eddy current calibration groups exceeded the four-hour limit for calibration verification. This is a requirement of Procedure 73TI-9RC01, Paragraph 8.3.3. The licensee's root-cause analysis identified several reasons that the calibrations were not done:

- In some cases, the operator was not examining any tubes when the four-hour calibration requirement was required.
- In some cases, the operator was performing activities without problems and simply lost track of the time requirement. There was no mechanism established to remind the operator when the 4-hour limit was approaching.
- In some cases, as the four-hour limit approached, the operator had problems getting the calibration completed. The inspector noted that calibration can often be difficult to obtain.

The licensee's corrective actions included conducting a stand-down meeting of eddy current personnel, the use of a preset timing device to alert the operator when the four-hour time period is going to expire, and having the primary and secondary data analysts make a report noting the beginning calibration time and the ending calibration time. This finding was licensee-identified and appropriate corrective actions were taken.

Stuck MRPC Probe

During this inspection period, a MRPC probe became lodged in a steam generator tube. This probe was removed by running another probe in from the cold leg and dislodging the struck probe. The root cause of this incident was that the operator was given an incorrect tube number. The programmer incorrectly entered the tube number, resulting in the acquisition operator probing the wrong tube. The operator was moving the MRPC probe quickly to the desired elevation; however, the probe was inserted into the tube's U-bend well before that desired level (for the correct tube) because he was provided with the wrong tube number. As a result, the probe became lodged in the U-bend.

The licensee's root-cause evaluation identified human error in two areas. First, the programmer entered the wrong tube number, and second the person responsible for checking that tube list against the original list, failed to note that an incorrect tube number had been entered. Corrective actions taken included writing a procedure for programming special interest tubes, such as this one. Personnel in data management had a stand down meeting to address attention to details and review the procedures for programming tubes.

7.1.3 Sampling Methodology and Expansion Criteria

The inspector reviewed the licensee's Unit 2 steam generator sampling methodology inspection plan. The inspection plan was reviewed to determine if

the licensee included inspection expansion criteria, historical steam generator data from licensee inspections and other utilities, and loose part monitoring.

The inspector found that the licensee's Unit 2 steam generator (SG) sampling plan included criteria for expanding the inspection scope. The inspector noted that the licensee's inspection plan included:

- a full tube length bobbin coil inspection of 4200 of the approximately 12,000 tubes in the two Unit 2 steam generators,
- an MRPC inspection at the top of the tubesheet for 2283 (in SG 2-1) and 2203 (in SG 2-2) of the hot leg tubes, and
- approximately 1800 tubes in the upper bundle area (in the arc of interest that analysis indicates to be most susceptible to free span cracking) from the first vertical support to the 08H support.

The inspector also found that the licensee's inspection plan included previous tubing indications found in Palo Verde steam generators and problems identified by other utilities, vendors, and the NRC.

The inspector concluded that the sampling methodology used to develop the inspection plan included the areas necessary to provide information needed to ascertain the condition of the steam generators tubes. The inspector found the sample expansion criteria used to be satisfactory.

7.1.5 Inspector and Analyst's Qualification

The inspector reviewed licensee qualification and certification requirements for steam generator eddy current inspectors and data analysts. Licensee requirements for steam generator eddy current inspectors were included in licensee procedure 73TI-9RC01.

The inspector reviewed approximately thirty eddy current and analysis personnel qualifications. The inspector found that licensee and contractor personnel qualification and certification records were up-to-date and that the inspectors or analysts were qualified in accordance with licensee procedure 73TI-9RC01. The inspector also found that the licensee and contractor inspectors were certified level I, II, or III in accordance with American Society for Nondestructive Testing Standard SNT-TC-1A.

7.2 Steam Generator Chemical Cleaning - Unit 2 (37703, 42700, 62700)

The inspector reviewed the licensee's preparations for chemical cleaning the secondary sides of the Unit 2 steam generators. The primary purpose of the chemical cleaning was to remove steam generator tube deposits that could become initiation sites for intergranular stress corrosion cracking. During previous eddy current testing of Unit 2 steam generators, the licensee observed axial cracks in steam generator tubes at locations where deposits

existed. The licensee contracted with B&W Nuclear Technologies (BWNT) to perform the chemical cleaning operation.

The chemical cleaning process used different solvents to remove magnetite and copper deposits from the steam generator internal surfaces. The generic process solvents were developed by the Electric Power Research Institute and the Steam Generator Owners Group (EPRI/SGOG), and the process had been previously used at other nuclear facilities.

7.2.1 Process Qualification

The inspector reviewed portions of ABB Combustion Engineering and BWNT reports which evaluated steam generator materials, determined corrosion allowances for materials in contact with solvents, and described laboratory tests to determine the effectiveness of the solutions for dissolving deposits. Samples of tubes previously removed from Unit 2 Steam Generator 2-2 were used in portions of the laboratory tests. As a result of the laboratory tests, BWNT modified the generic EPRI/SGOG process to apply to Palo Verde Unit 2 conditions. The inspector discussed the qualification of the process with licensee and BWNT representatives. The reports provided a detailed background of the process qualification and the individuals appeared to be very knowledgeable of corrosion allowances, susceptible materials, and process qualification testing.

The inspector also reviewed two 10 CFR 50.59 evaluations prepared by the licensee for the cleaning evolution. One of the evaluations indicated that there was no plausible accident which would result in the simultaneous failure of more than one chemical container and that a spill of 55 gallons of ammonium hydroxide (one container) would not affect control room habitability. During discussions with BWNT personnel, the inspector learned that up to four containers of ammonium hydroxide could be moved at one time using a forklift. The inspector commented to the licensee that moving four containers at one time could result in dropping and failure of the containers, which was not reviewed in the 10 CFR 50.59 evaluation. The licensee subsequently determined that failure of four ammonium hydroxide containers would not affect control room habitability.

7.2.2 Process Implementation

BWNT supplied the equipment for performing the process, and the inspector walked down the majority of the equipment which was located outside of containment in the radioactive waste yard. The inspector observed that the equipment was in good condition, components were labeled, and there were no indications of leaks from components that would carry chemical solvents. The inspector found that BWNT equipment operators and process engineers were familiar with the operation of the equipment and were familiar with the overall process.

The inspector observed portions of pre-cleaning system operational testing which was performed to verify equipment operation and to ensure that procedures were appropriate. The inspector considered that the pre-cleaning operational testing was beneficial in ensuring successful performance of the

evolution. The inspector reviewed portions of various procedures used for the evolution and found the procedures to be appropriately detailed. The procedures had been approved by the licensee, and procedure changes were made in accordance licensee requirements.

The inspector discussed the implementation of the process with various licensee organizations including Operations, Quality Control, Radiation Protection, Chemistry, Fire Protection, and Quality Assurance. The inspector found that the organizations were adequately involved in preparing for the process; however, it appeared that the licensee's project manager was not receiving all of the comments or concerns generated by the organizations. The licensee intended to conduct pre-evolution briefings for all involved organizations and based on comments from the inspector, the licensee intended to make procedure changes to ensure that licensee organizations were involved in concurring to start the process.

7.2.3 Contingencies

The inspector observed that chemical spill kits, showers, and eyewash stations were staged at various locations and that BWNT personnel appeared to be knowledgeable of chemical hazards. The inspector discussed contingencies with personnel from the Palo Verde Fire Department and found that personnel had been trained to respond to spills or a fire. The inspector found that procedures contained contingency actions if chemistry results or corrosion rates were not in expected parameters.

Licensee representatives were assigned to work with the BWNT personnel during the evolution to provide coordination with licensee organizations for both normal or abnormal operations, and the inspector found these personnel to be knowledgeable of the process and their assigned duties.

The inspector discussed contingencies for handling contaminated solutions with licensee Radiation Protection personnel and with BWNT chemists. The inspector found that while licensee personnel expected the solvents to become contaminated as a result of the previous Unit 2 steam generator tube rupture, the BWNT personnel did not expect contaminated solvents based on past experience at other facilities. The inspector commented that the expectations of the licensee and the contractor appeared to differ and that additional coordination may be needed to ensure that the contractor would be prepared to implement contingencies imposed by Radiation Protection. As a result, the licensee revised the Radiation Exposure Permit for the process, specified Radiation Protection expectations, assigned additional technicians to the job, and worked with contractor personnel to ensure that licensee expectations were understood.

7.2.4 Chemical Cleaning Performance

The inspector observed portions of the chemical cleaning operations and closely followed the licensee's progress. Overall, the inspector observed good operations practices and noted good communications between BWNT and the licensee. However, the inspector noted that some activities had not been adequately controlled. For example,

- During the transfer of equipment inside containment from Steam Generator 2-1 to the Steam Generator 2-2, one person was sprayed with chemical solution on his clothing and another person was sprayed in the face. The leaking connection was immediately reconnected and the leak stopped. The person sprayed in the face used the eye wash station to rinse his face. Both individuals exited containment, and showered. Neither individual experienced side effects from the solution. The licensee re-briefed all chemical cleaning personnel on the requirement to wear face shields and proper protective clothing when working with chemical cleaning systems. Subsequently, BWNT used a large catch basis to collect possible leakage and provided coverage over connection being opened to reduce the possibility of spray.

- On February 11, a spill of water and corrosion products occurred outside the Unit 2 containment hatch when operators aligned a sludge lancing tank to the chemical cleaning system. The spill had resulted from the improper manipulation of one of the sludge lancing system valves. The BWNT operator did not have specific instructions to manipulate the valve and was not cognizant of the system configuration. The licensee initiated procedure changes to ensure that sludge lancing valves are not re-positioned unless directed by a supervisor.

- The licensee fire captain, the leader of the hazardous material response team, was called to respond to the February 11 spill. He had difficulty determining who was the BWNT contact at the scene and it took several minutes for the captain to find the BWNT contact. As corrective action, BWNT established that the person in charge of the chemical cleaning operation would be required to identify himself to the fire captain upon arrival of the hazardous material response team. (Note: The spill that occurred on February 11 was subsequently determined not to be a hazardous material.)

In addition, the inspector noted that the licensee responded appropriately to level indication problems observed during the chemical cleaning. The steam generator 2-2 level gage was blown down with nitrogen several times in attempts to achieve an accurate level indication. BWNT operators monitored the amount of solution pumped into the steam generator and compared this with the indicated level and used the lower of the two indications as the level. This conservative action ensured that the unanalyzed metal portions of the steam generator would not be exposed to cleaning chemicals. Subsequently, operators determined that the top portion of the tube bundle had not been cleaned. As a result, the cleaning process was increased by 20 hours so that the top of the tube bundle could be cleaned. To resolve the level inaccuracy problems, the licensee planned to use the six-inch hand hole as a tap for an attachment for the level instrument in the upcoming Unit 3 steam generator chemical cleaning.

The inspector concluded that the licensee response to the events that occurred during the chemical cleaning of the steam generators was adequate.

7.2.5 Results

Chemical cleaning removed approximately 5600 pounds of material from Steam Generator (SG) 2-1 and approximately 5000 pounds of material from SG 2-2. The bulk of the material removed was iron. Other material removed included nickel, manganese, and small amounts of copper, zinc, and chromium. Sludge lancing subsequently removed approximately 400 pounds of material from SG 2-1 and approximately 500 pounds of material from SG 2-2.

The licensee found that the levels of chromium in the corrosion products removed resulted in the classification of the material as mixed waste (both hazardous and radioactive waste). At the end of the inspection period, the licensee was evaluating the waste to determine the actions necessary for its disposal.

The photographs of the SG tubes were taken before and after steam generator cleaning. The licensee determined that chemical cleaning successfully removed deposits on the steam generator tube surfaces.

The axial crack indications from eddy current testing (ECT) in SG 2-2 became more prevalent after the chemical cleaning. Steam Generator 2-1 had no appreciable difference in the before and after results of the ECT. At the end of the inspection period, the licensee and the NRC's Office of Nuclear Reactor Regulation (NRR) were reviewing these results.

7.3. Oconee Tube Plugging Problems

The inspector reviewed the possibility of a plug installation error occurring at Palo Verde similar to the one that caused 14 plugs to become dislodged from an steam generator at Oconee Unit 3 in South Carolina. The dislodged plugs were discovered during a refueling outage that commenced on January 2, 1994. These plugs had been improperly installed during the August 1992 outage by the same contractor that performed the tube plugging at Palo Verde.

The contractor explained to the inspector that the plug-rolling tool used at Oconee was an older model than the one used at Palo Verde. This tool used a flow verification assembly to monitor the air flow and air pressure delivered to the air motor which was used to roll the plugs. When the proper amount of air flow and air pressure were reached, the assembly would stop the air flow. However, this method did not measure the actual torque applied to the plug, nor could it detect problems in the rolling process such as a misaligned tool.

The contractor uses the Delta roll expansion tool at Palo Verde. The Delta roll tool provides an on-line feedback of the installation torque. The contractor developed a torque trace method using the Delta tool called a "roll energy" verification. The roll energy verification integrated the area under the torque verses time curve which was proportional to the work applied to the plug. Because the work applied to the plug was proportional to plug wall thinning, it could be used to determine how well the plug was secured to the tube. Additionally, this method could reveal improper lubrication, tool alignment and other problems by changes in the shape of the curve and the amount of time required to roll the plug. The inspector concluded that this

method provided appropriate assurances that the plugs were adequately secured to the tubes.

8 REVIEW OF EMPLOYEE CONCERNS PROGRAM (92720)

As of January 26, 1994, the following statistics were noted with regard to the ECP files initiated by the licensee during the last four years:

	1991	1992	1993	1994
Number of ECP concerns submitted:	129	251	199	1
Number of submitters:	94	144	133	1
Number of anonymous submitters:	12	17	14	0
Number of concerns assigned outside ECP:	92	136	113	0
Average length of time to close file (weeks):	5	15	12	2
Longest period file was open (weeks):	19	80	42	2
Number of concerns substantiated:	22	42	23	
Number of files remaining open:	0	20	41	1

The inspector reviewed the licensee's ECP procedures, a random selection of ECP files closed within the last several months, and interviewed several licensee employees who had submitted ECP concerns. The inspector noted that the licensee has recently initiated a comprehensive effort to reduce the backlog of open ECP files. The inspector noted the following concerns in that regard:

- The licensee's ECP procedure (60AC-OQQ22) requires that an ECP file be initiated for every concern received by the ECP group. Historically, this has resulted in a large number of files being opened and independently investigated by the ECP group which were not related to nuclear safety, which would more appropriately be handled by another group. The licensee has implemented a program of screening concerns received by the ECP group, and making a determination as to whether to initiate an ECP file or to refer the concern to another licensee organization for resolution. However, this new screening program and associated new "initial contact form" has not been incorporated into the ECP procedure. As a result the criteria for initiating an ECP file are not clearly or consistently defined, nor are the bases for such determinations clearly or consistently documented or retrievable. In one instance, the inspector noted that a concern received on October 1, 1993, involving inadequate pre-maintenance tailboard meetings and poor ALARA, appeared to warrant opening of an ECP file.

- Many ECP files have been closed without a final closure letter being sent to the concerned employee, as required by the licensee's ECP procedure.

- ECP file 93-130-01, which involved potential discrimination, was closed on the basis that the concerned employee requested that the concern be withdrawn. Based on a review of the employee's concerns and discussion with the employee, the inspector concluded that the licensee failed to properly resolve this concern. As a result, the licensee missed a

significant opportunity to reenforce its stated commitment to a timely and discrimination-free resolution of employee concerns. In particular, the involved employee stated that he would not use the licensee's ECP program in the future because he was convinced that licensee managers had conducted a "witch hunt" to identify him as the alleger. The employee had only withdrawn his employee concern on the basis that he had already gone to his manager and identified himself as the alleger. The concerned employee told the inspector that none of the managers in the employee's reporting chain or from the ECP group had ever sat down with him to resolve his discrimination concern. This failure has the potential to created a "chilling effect" that is likely to reach further than the involved individual, since he continues to interface with other licensee employees with the belief that he was not properly treated.

- The licensee has a long history of a high volume of both technical and discrimination concerns coming into its ECP program, as well as having the highest incidence in Region V of substantiated, employee discrimination concerns submitted to the NRC and the Department of Labor.

- ECP files involving substantiated concerns did not consistently document or reference documents for tracking corrective action followup (e.g. file 93-010-01, and 93-109-05). In the instance of file 93-109-05, it was not clearly documented that the licensee had thoroughly evaluated the impact of failed snubbers.

The licensee acknowledged the inspectors comments and stated that actions would be taken to correct the problems noted by the inspector.

9 TRAINING AND QUALIFICATION EFFECTIVENESS (41500)

In late 1993, the NRC was made aware of concerns that the operators at Palo Verde could be reluctant to take actions in the simulator because adverse actions would be taken against them if they misdiagnosed a problem. In order to address this concern, an NRC inspector interviewed five reactor operators and five senior reactor operators on January 26, 1994. Four individuals were from Unit 1, two from Unit 2, and four from Unit 3.

Eight individuals clearly stated that they would always take appropriate actions in the simulator or in the plant and that they were not influenced by a fear of adverse actions if they misdiagnosed a problem. They all stated they would take the correct actions. One of the eight stated that he had been challenged by personnel from another facility concerning "malicious compliance" during the Palo Verde steam generator tube rupture event, but clearly stated to that individual and to the inspector that no "malicious compliance" was intended or occurred.

One individual stated he would not hesitate to take the correct actions, both in the simulator and in the plant, but that requirements for strict adherence to procedures in the past had caused him some fear. He went on to state that the manner in which the steam generator tube rupture event was dealt with by procedures was slow. The operators knew they had a steam generator tube

rupture and what they had to do, but were frustrated by the plant procedures. Although there were no safety implications, the delays complicated recovery and cost the utility a lot of money. The individual indicated that the facility now recognizes these problems and it appears they are headed in the correct direction (i.e., to give operators reasonable flexibility). Starting last year senior management has repeatedly asked for operators' inputs and these issues have been identified.

Regarding the delays complicating the recovery from the steam generator tube rupture, the inspector observed that since the steam generator tube rupture event the facility has provided additional guidance and training to ensure operators can complete appropriate emergency steps early. In October 1993, the facility also committed to the NRC to completely review and revise the emergency procedures to make them more usable for the operators. The inspector concluded that these two corrective actions adequately resolved the operator's concern.

One other operator stated that he would make the best decision he could and follow through regardless of what others would do to him. He did not have any specific problems in mind, but was concerned about the constant emphasis on accidents and training far beyond the design-basis events described in the Final Safety Analysis Report. He felt that operators may cause problems because they were looking too hard for problems during an uncomplicated trip when there were no problems.

The inspector discussed this issue with the operator, but did not identify any significant safety concerns. The inspector agreed that the scenarios used for training or testing are often beyond the plant design basis, but this provides a safety margin for operators, training, and plant procedures. The operator did identify two procedure steps in emergency operating procedures which, to be useful, almost always had to be completed early. These step directed the sampling of the steam generators, and restoration of power to non-vital 480 Volt AC busses. The inspector found that the planned revision of the licensee's emergency operating procedures should help this problem, and that operators had been trained to complete steps early when necessary. The inspector concluded that there was no need to correct existing training.

The inspector determined that all the individuals interviewed understood the facility policy for following procedures and were confident they were implementing these procedures. The operators did not identify any safety problems and were aware of the emergency provisions of 10 CFR 50.54(x).

At the conclusion of the inspection the inspector discussed the findings with the Manager of Operations Training and the Vice President, Nuclear Generation to ensure they were aware of the issues raised by the operators.

10 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS (92702)

10.1 (Closed) Violation 50-529/93-04-02: Fire Protection Test Procedure not Followed - Unit 2

This violation was issued after a fire protection technician failed to perform a surveillance test in accordance with the procedure. The technician performed procedure steps out-of-order, did not establish and maintain communications, and signed off restoration steps prior to completing the procedure.

The licensee reviewed the incident and determined that the violation was caused by personnel error. The technician believed that the requirement to perform steps sequentially was general guidance and that steps could be performed in a different sequence if the objectives of the test were still being met. The licensee counseled the technician regarding procedural compliance. Additionally, the licensee briefed the entire fire department on the incident and the need for procedural compliance. The inspector concluded that these steps were appropriate for this violation.

10.2 (Closed) Violation 50-529/93-35-02: Failure of Offsite Safety Review Group to Review Abnormal Indication - Unit 2

This violation was issued because the Offsite Safety Review Group (OSRC) failed to review abnormal indications obtained during the third Unit 2 refueling outage in 1991. The licensee had discovered one axial mid-span crack and six axial cracks at the first tube support. Technical Specification 6.5.3.4f required the OSRC (formerly the Nuclear Safety Group) to review abnormalities or deviations from normal. The inspector reviewed the licensee's response to the violation and determined that they were appropriate.

The licensee acknowledged that the abnormal indications should have been reviewed by the OSRC. Following the tube rupture in Unit 2, the licensee formed a steam generator task force, consisting of senior managers and engineers, to evaluate the failure. The licensee intended to develop the task force into a permanent group whose mission was to identify and predict failure modes and determine and implement strategies to minimize steam generator problems. The licensee stated that steam generator group would make a presentation to the OSRC if steam generator testing revealed a significant deviation or abnormality, or the necessity for a reduced operating cycle.

The inspector concluded that the licensee's level of management involvement in the site's steam generators and the formation of a permanent steam generator group should ensure that future steam generator problems are addressed by the appropriate level of management.

10.3 (Closed) Violation 50-529/93-40-04: Surveillance Test (ST) Administrative Procedure Not Followed - Unit 2

This item involved operations personnel in Unit 2 not following the administrative controls for surveillance testing documentation. Specifically,

contrary to the administrative procedure governing surveillance testing, operators did not mark a step unsatisfactory during the performance of a charging pump surveillance or make a test log entry documenting the problem. The item also noted that the Unit 1 Operations personnel did not understand when the administrative requirements for surveillance tests were applicable. This had resulted in a previous violation (Violation 50-528/93-26-01).

The inspector reviewed the licensee's response to the previous violation in NRC Inspection Report 93-43 and noted that the licensee's corrective actions included forming a focus group to improve the overall surveillance testing administrative procedure. The inspector noted that an extensive revision to the surveillance testing administrative procedure was issued in December 1993. The inspector reviewed the revision and noted that Step 3.6.1 stated that "...any failed step or out of tolerance data shall be identified by circling the initialled space or data entry." The step also has specific instructions for notifying the operation's shift supervisor, making a test log entry, and initiating a work order or CRDR. The inspector concluded that the revision to the procedure clarified management's expectations for documenting problems during surveillance tests. The inspector also noted examples in the field (see Section 5.2 of this inspection report) where problems noted during surveillance tests were properly documented.

11 FOLLOWUP (92701)

11.1 (Closed) Inspection Followup Item 50-530/93-11-05: Magne-Blast Breaker Inoperability - Close Latch Spring Interference

This item involved the inoperability of a safety-related General Electric (GE) Magne-Blast breaker due to interference of the close-latch spring with the close-latch monitoring switch. This item was left open to review the licensee's actions regarding several recommendations listed in Condition Report/Disposition Request (CRDR) 3-3-0152.

The licensee's first recommendation was to issue a plant change request to annunciate any failure of the breaker closing springs to charge in the control room. Plant engineering initiated Plant Change Request PCR 93-13-PB-001 in July 1993. The PCR was approved by the plant modification committee on January 24, 1994. The modification will be prioritized and scheduled for installation.

The licensee's second recommendation was to issue an engineering evaluation request (EER) to permit the use of torsion type close latch springs on Magne-Blast Breakers. EER 93-PB-004 was written to allow using the torsion springs as a design equivalent change and directed the replacement of the older style springs during scheduled breaker overhauls.

The licensee's third recommendation was for the licensee to obtain service advice letters (SALs) and other information regarding the spring changes from the vendor, General Electric (GE). The licensee determined that GE had not issued any SALs concerning the new-style, close-latch springs or any problems with the springs that would prevent the charging of the closing springs.

The licensee's last recommendation was to revise all the applicable maintenance and surveillance procedures to ensure there was sufficient clearance between the spring and the closing mechanism. The inspector reviewed the overhaul procedures for the various types of GE magne-blast breakers (32MT-9ZZ37 through 32MT-9ZZ39) and noted that steps were included to ensure a minimum of 1/8-inch clearance existed between the spring and the closing mechanism.

On January 4, 1994, NRC Information Notice 94-02 was issued describing this event and the potential impact on breaker operation. The inspector concluded that the licensee's recommended corrective actions were appropriately implemented.

11.2 (Closed) Inspection Followup Item 50-529/93-55-01: Reactor Coolant System Flow Anomaly

This followup item involved a review of the licensee's analysis of reactor coolant system (RCS) flow anomalies. On the evening of January 6, 1994, with Unit 2 at 85 percent power, operators noted that RCS flow had dropped approximately 2 percent over the previous 12 hours, as indicated by the flow instruments for all four reactor coolant pumps (RCPs). The operators also noted increases in the differential pressure across the RCPs (approximately 2 percent) and across the core (approximately 1 percent), and increases in RCP amperes (approximately 5 percent) for all four RCPs. These RCS parameters appeared to have gradually changed over a 12-hour period and then stabilized. Reactor power and the RCS hot leg and cold leg temperatures did not change appreciably.

The licensee concluded that change in RCS flow resulted from the build-up of a thin, rough layer of corrosion products on the fuel rods. The deposit of corrosion products appeared to result from the planned reduction of RCS lithium concentrations. This reduced RCS pH and apparently caused corrosion products in colder parts of the system to go into solution and plate out on the relatively hotter fuel rods. The licensee calculated that a layer of corrosion products approximately 0.0003 inches thick could result in the flow decrease observed.

Prior to the flow anomaly, operators had been reducing RCS lithium concentration in preparation for the mid-cycle outage. This process is used to initiate a "crud burst" during RCS cooldown that allows operators to remove RCS corrosion products through the chemical and volume control system. This reduces the radiation levels in the RCS, particularly the steam generator bowls. The licensee concluded that they had maintained RCS chemistry within industry established guidelines. However, the RCS lithium concentration, which is proportional to boron concentration, was high since the Unit was early in its operating cycle. Therefore, the net change in lithium concentration and, subsequently RCS pH, was significantly greater than has been typically experienced during a plant shutdown at the end of an operating cycle.

The licensee concluded that the change in RCS flow did not impact plant safety. Throughout the anomaly, core flow remained above design flow as well

as Technical Specifications minimum flow requirements (95 percent of design flow). Additionally, the licensee determined that core physics parameters had not been affected. The licensee expects that normal RCS chemistry controls following plant restart will remove the layer of corrosion products from the fuel rods and that RCS flows should return to normal.

The licensee discussed their analysis with the resident inspectors and the staffs of Region V, and the NRC's Offices of Nuclear Reactor Regulation, and Analysis & Evaluation of Operational Data during a conference call on January 31, 1994. Their analysis was determined to be acceptable.

12 ONSITE REVIEW OF LICENSEE EVENT REPORTS (92700)

12.1 (Closed) Licensee Event Report 50-530/93-03, Revision 0: Emergency Diesel Generator (EDG) Unable to Start and Run in the Manual Test Mode

This LER reported an event where the "B" EDG in Unit 3 was not capable of being manually started from the control room from July 3-10, 1993. As a result, the licensee determined that the EDG was inoperable since the Technical Specifications (TS) requirement to start the EDG in the manual test mode could not have been performed during this period. The inspector conducted a review of the event to determine the safety significance of not being able to manually start the EDG from the control room.

The manual test method of starting the EDG is primarily used to verify the engine is functional following maintenance on the EDG. When the EDG is started in this mode, additional protective shutdowns are provided in case the maintenance introduced a condition adverse to the safe operation of the EDG.

The inspector determined that the EDG could have been started manually using the simulated loss of offsite power (LOOP) and simulated emergency safeguards features (ESF) manual start buttons at the local EDG control panel. These methods of starting are used to test the design features described in the safety analysis for the EDG to start on a LOOP or ESF actuation. Additionally, the EDG was able to automatically start in the event of an actual LOOP or ESF actuation.

The inspector concluded that the safety significance of this event was low since the EDG would have automatically started as designed and also could have been manually started from the local control panel.

13 IN OFFICE REVIEW OF LICENSE EVENT REPORTS (90712)

LER 50-528/93-04, Revision 1, "ASME Section XI Testing of Charging Pumps not in Compliance with Code Requirements" was closed based on in-office review.

ATTACHMENT

1 PERSONS CONTACTED

Arizona Public Service Company (APS)

*R. Adney, Plant Manager, Unit 3
*K. Akers, Quality Assurance
*W. Chapin, Manager, Refueling and Maintenance Services
*R. Cherba, Manager, Quality Audits
R. Flood, Plant Manager, Unit 2
*R. Fountain, Supervisor, Quality Audits and Monitoring
*B. Grabo, Supervisor, Nuclear Regulatory Affairs
*W. Ide, Plant Manager, Unit 1
*J. Levine, Vice President, Nuclear Production
D. Mauldin, Director, Site Maintenance and Modifications
J. Minnicks, Manager, ECP Program
J. Ong, ECP Investigator
*G. Overbeck, Director, Site Technical Support
F. Riedel, Manager, Operations, Unit 1
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*K. Roberson, Senior Engineer, Nuclear Regulatory Affairs
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*C. Russo, Manager, Quality Control
*J. Scott, Assistant Plant Manager, Unit 3
*C. Seaman, Director, Quality Assurance and Control
M. Searcy, ECP Investigator
*M. Shea, Manager, Radiation Protection
*R. Stevens, Director, Nuclear Regulatory & Industry Affairs
R. Stroud, ECP Investigator
P. Wiley, Manager, Operations, Unit 2

Others

*R. Henry, Site Representative, Salt River Project
*P. Luther, Site Representative, Public Services New Mexico

* Denotes personnel in attendance at the Exit meeting held with the NRC resident inspectors on February 16, 1994.

2 EXIT MEETING

An exit meeting was conducted on February 16, 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 inspectors acknowledged that the licensee had provided various proprietary steam generator chemical cleaning reports for NRC review. The proprietary information was subsequently returned to the licensee.