ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/95-12
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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, AZ

Inspection Conducted: May 21 through July 1, 1995

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Approved: _____ 7/26/95
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Inspection Summary

Areas Inspected (Units 1, 2, and 3): Routine, announced inspection of onsite response to plant events, operational safety, maintenance and surveillance activities, onsite engineering, and followup items.

Results (Units 1, 2, and 3):

Operations

Operations performance during the inspection period was generally good, as evidenced by:

- Implementation of revised Emergency Operating Procedures, which were seen as a significant improvement (Section 3.5).

- Good operations management assessment of a Unit 1 reactor trip (Section 2.1).

- Excellent communications and coordination between operations and maintenance personnel in addressing an emergency diesel generator problem which placed Unit 2 in a Technical Specification shutdown action statement (Section 2.2).

- One noted exception involved operator failure to question indication that a Unit 1 emergency diesel generator was not operating at 60 hertz (Section 3.7).

Maintenance/Surveillance

Maintenance performance during the period was mixed. A number of maintenance related issues surfaced at the end of the Unit 1 refueling outage. Examples of inspector identified concerns included:

- Inappropriate use of nonseismically qualified scaffolding in Units 1 and 2 (Section 3.1).

- Inadequate evaluation and resolution of observed problems with the Unit 1 auxiliary feedwater turbine governor valve (Section 4.1).

- Two examples of field work performed without appropriate reference to the applicable work instruction, involving modification of the Unit 3 fuel pool storage racks (Section 4.5), and surveillance testing of safety injection system check valves (Section 5.1). The latter example resulted in a test procedure violation which could have invalidated the test results.

Engineering and Technical Support

The licensee took prompt action in response to an industry event database entry on Target Rock solenoid operated valves which might impact valves installed at Palo Verde (Section 6.4).

However, in some other instances of problems encountered at Palo Verde, although the licensee took appropriate actions for its own equipment, they had not appropriately explored the generic implications of the deficiencies. Examples included problems with cracked Valcor solenoid operated valve bodies (Section 6.2), auxiliary feedwater turbine governor valve packing problems (Section 4.1), and the potential for an auxiliary feedwater turbine trip during an excess steam demand event (Section 6.3).

Although the licensee had initiated a comprehensive program for thermal monitoring of environmentally qualified equipment, in response to a previously identified weakness, appropriate interim action had not been taken to verify

that field temperatures were not significantly different from those required by the qualification reports (Section 6.1).

Management Oversight

The inspectors noted excellent management involvement in the resolution of an emergency diesel generator problem which placed Unit 2 in a Technical Specification shutdown action statement (Section 2.2), the evaluation of scaffolding deficiencies (Section 3.1), and the followup of a Unit 1 reactor trip (Section 2.1).

However, licensee management did not provide appropriate oversight for the evaluation and resolution of Unit 1 auxiliary feedwater turbine governor problems (Section 4.1). As a result, the conclusions of the evaluation were not well supported.

Summary of Inspection Findings:

- One noncited violation was identified (Section 3.1)
- One violation was identified involving failure to comply with a surveillance test procedure (Section 5.1)
- One violation was closed (Section 7.1)
- Three unresolved items were closed (Sections 8.2, 9.1, and 9.2)
- One deviation was closed (Section 9.3)
- One followup item was closed (Section 8.1)

Attachments:

1. Persons Contacted and Exit Meeting
2. List of Acronyms

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 started the inspection period in Mode 3 with a reactor coolant system (RCS) heatup in progress following a refueling outage. On May 25, the unit commenced a startup and was synchronized to the grid on May 27. On May 30, the unit experienced a reactor trip on low steam generator level from 65 percent power after to a feedwater isolation valve closed during maintenance (Section 2.1). On May 31, the unit commenced reactor startup and synchronized to the grid the following day. The unit increased power to 100 percent and operated throughout the inspection period at essentially 100 percent power.

1.2 Unit 2

Unit 2 started and ended the inspection period at 100 percent power.

1.3 Unit 3

Unit 3 started the inspection period at 100 percent power. On June 4, reactor power was reduced to 85 percent to repair tube leaks identified on Feedwater Heat Exchanger 11A. On June 8, following repairs, the unit returned to 100 percent power for the remainder of the inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Reactor Trip Following Feedwater Isolation Valve Closure - Unit 1

On May 30, at 10:22 p.m., Unit 1 tripped from 65 percent power on a low steam generator (SG) level in SG 12. The low SG level resulted from inadvertent closure of feedwater isolation valve SGB-137. Plant systems responded as designed, and the trip was uncomplicated.

Electrical maintenance electricians were in the process of replacing a coil for a solenoid operated valve associated with the hydraulics for the actuator of Valve SGB-137 prior to the reactor trip. The electricians were attempting to terminate the coil leads for solenoid operated Valve D onto a terminal block. Subsequent licensee troubleshooting determined that the electricians had disturbed a loose termination for solenoid operated valve Coil A, which was terminated in the same junction box. As a result, the coil lost power and actuated Valve SGB-137.

The terminal block for solenoid coil A used a compression screw that was loose. The licensee repaired the loose termination and performed a subsequent inspection of the terminations for other valves with similar terminal blocks. This inspection included the other feedwater isolation valves and the main steam isolation valves.

The inspector observed excellent involvement by plant management in the post-trip review. Management took a cautious approach to identifying the cause of

the trip and appropriate actions in assessing the potential impact on other equipment.

2.2 Entry Into Technical Specification (TS) 3.0.3 Following an Emergency Diesel Generator (EDG) Spurious Actuation

On June 13, at approximately 11:20 a.m., control room operators received a high priority trouble and engine trip alarm for the Train B EDG, and an automatic start of the Train B spray pond pump and the Train B EDG building essential fans. Control room operators investigated the alarms and determined that the Train B EDG had not received a valid start signal. The licensee declared the Train B EDG inoperable and began troubleshooting activities.

Control room operators subsequently performed the surveillance test (ST) procedure used to demonstrate operability of the remaining sources of AC power when one EDG was declared inoperable, as required by TS 3.8.1.1. The ST procedure required the licensee to declare both trains of a safety-related component inoperable if the Train A component was unavailable while the Train B EDG was inoperable. The inspector noted that these requirements were more restrictive than the requirements of TS 3.8.1.1.

During performance of the ST, control room operators noted that the Train A essential cooling water (ECW) pump, the Train A auxiliary feedwater (AFW) pump, and the Train A hydrogen recombiner (HR) were out of service for maintenance when the Train B EDG was declared inoperable. The shift supervisor subsequently declared both trains of ECW, HR and AFW inoperable, and entered TS 3.0.3 and Action b of TS 3.7.1.2, as required by the surveillance procedure. The most restrictive action statement required the plant to be in hot standby within 6 hours. The inspector noted good involvement by operations management in the review of the TS and ST requirements.

The inspector asked the shift supervisor and the shift technical advisor when they planned to commence a plant shutdown to ensure that the plant was safely shutdown within the 6-hour time limit. The operators determined that it would take approximately 3 hours to perform a controlled shutdown, and planned to start a shutdown at 2:30 p.m. The inspector concluded that the shift supervisor's actions to initiate a planned shutdown were appropriate.

The licensee restored all the Train A equipment at approximately 2 p.m. and exited TS 3.0.3 and 3.7.4. The inspector observed good coordination between operations and maintenance to promptly restore the Train A components.

The licensee determined that a faulted speed probe for the Train B EDG sent an erroneous signal to the start circuitry that the engine was running which caused the essential fans and spray pond pump to start. The EDG subsequently received a trip signal due to actual low lube oil and cooling water temperatures because the engine was not running. The licensee found a crack in the amphenol connector for the speed probe that caused an electrical short in the circuit. The licensee initiated a condition report/disposition request (CRDR) to determine the cause of the failure and to identify appropriate corrective actions. The inspector observed good troubleshooting efforts and agreed with the licensee's conclusion that the speed probe failure initiated

the event and would not have prevented the EDG from starting during an emergency.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control of Scaffolding Around Safety Related Equipment

During walkdowns of the Unit 2 auxiliary building and the Unit 1 main steam support structure on May 25, the inspectors identified four instances where scaffolding in areas with seismically qualified equipment had tags which indicated that the scaffolding had not been erected to seismic criteria. The examples were as follows:

- Both Unit 1 AFW pump rooms had scaffolding erected to support modifications to the turbine driven AFW pump steam drains.
- Unit 2 ECW pump Train B room had scaffolding erected to support evaluation of the seismic qualification of the ECW process radiation monitors and associated piping.
- Unit 2 120-foot elevation hallway had scaffolding erected.

The inspectors notified the Unit 1 shift supervisor (SS) and the Unit 2 control room supervisor (CRS). The inspector was promptly called by the Civil Engineering Team Lead and informed that CRDR 9-5-560 had been initiated and that walkdowns of scaffolding in all units would be performed. The licensee subsequently found that scaffolding had been erected in the Units 1 and 3 ECW Train B pump rooms which was tagged as nonseismically qualified.

The inspector was informed the following day by the Site Shift Manager (SSM) that the Operations Director had established an investigation team. The licensee determined that in all but two instances, the scaffolding had been erected to seismic criteria established in licensee Procedure 30DP-9WP11. The two exceptions were scaffolding in the Unit 1 AFW rooms and the Unit 3 ECW Train B pump room. The scaffolding was modified to meet the procedure specifications. In addition, licensee civil engineers performed calculations of the as-found conditions of the scaffolding and determined that it would not have damaged seismically qualified equipment during a seismic event.

The inspector reviewed the evaluation and agreed with the licensee that the incorrectly installed scaffolding had minimal safety significance. Therefore, the failure to follow the seismic criteria for installing the scaffolding constitutes a violation of minor significance and is being treated as a Noncited Violation, consistent with Section IV of the NRC Enforcement Policy.

3.1.1 Corrective Actions

The licensee performed a cause evaluation and identified several areas of concern:

- In some instances, the carpenters erecting the scaffolding had applied the seismic criteria of the component to be worked on to the

scaffolding. In the case of the scaffolding in the ECW pump rooms, work was to be performed on the non-seismically qualified process radiation monitors (RU3). However, the scaffolding was erected in close proximity to seismically qualified ECW equipment.

- In the case of the Unit 1 AFW rooms, the scaffolding had been erected during the refueling outage when the AFW system was not required to be operable. The modification work order, which included the scaffolding, was being tracked by the control room as a mode change hold. However, after the modifications had been completed and outage management emphasized work order closeout during plant restart to support mode transitions, the carpenters closed the step in the initial work order to remove the scaffolding and opened a new work order to remove the scaffolding.

- Individuals from Nuclear Assurance - Maintenance had used the scaffolding, and operations auxiliary operators (AO) had routinely toured the rooms prior to the identification of concerns by the inspector. Licensee management expectations for both groups was that they should have identified the scaffolding deficiencies.

- The licensee identified several seismic tag deficiencies.

Although the scaffolding issues appeared to be isolated to the practices of one crew, the licensee conducted a "stand-down" with all carpenters to discuss the findings and to clarify expectations. In addition, the licensee has initiated actions to clarify expectations for Nuclear Assurance personnel and AOs.

The inspector concluded that the licensee conducted a timely and thorough investigation of the issue and that the corrective actions were appropriate.

3.2 Radiological Controlled Area Mat Lifted By Wind

On May 22, during a plant walkdown of the Unit 3 yard radiological controlled area, the inspectors observed a large rubber mat become airborne as a result of a sudden burst of wind. The mat traveled 15 to 30 feet and landed on an adjacent radiological controlled boundary fence. The inspector noted that the area was unattended and notified Radiation Protection personnel.

The mat was a rubber sheeting material, approximately 90 by 90 feet in length, used as a temporary chemical cleaning berm. The berm was originally setup by contracting personnel for steam generator chemical cleaning which had been performed during the Unit 3 refueling outage in April 1994. The contractor was in the process of dismantling the berm and was awaiting a radiological survey of the berm before it was removed. They had dismantled portions of the berm which were holding the mats down.

The inspector estimated that the berm was within 100 feet of the essential spray ponds. The mat had been carried north and away from the spray ponds. However, the inspector concluded that the licensee had not been sufficiently

sensitive to the potential that the mat could have been carried into the spray ponds.

The inspector discussed the potential of the mat landing in the spray pond with the contracting supervisor and the system engineer. They stated that during setup and tear down periods, it had been expected that the berm area was not to be left unattended. The system engineer discussed barriers that are set in place to prevent material from entering the spray ponds and the procedure for controlling potential tornado borne missiles in the outside areas.

In response to the inspector's concerns, the licensee's project manager for the steam generator chemical cleaning project conducted meetings with the contractor which had set up the berm area. The licensee discussed its expectations regarding coverage of tear-down activities and the necessity for ensuring that potential hazards are secured. The inspector found these actions to be appropriate.

3.3 Loose Electrical Connections on Safety-Related Equipment in the Auxiliary Building

On May 19, the inspector identified loose connections on conduit pull boxes and motor-operated valves in the Unit 3 west mechanical penetration room. The inspector also identified three conduit pull boxes that had incorrectly installed gaskets and three junctions boxes with missing screws in the Unit 1 auxiliary building. The licensee determined that these conditions did not impact operability of the associated safety related equipment because any moisture that entered the system would go into the junction box and not the end device (e.g., motors, transmitters, solenoids, etc.). However, the licensee concluded that these conditions did not meet the specifications for installed conduit, and initiated work requests to correct the deficiencies.

The inspector concluded that although the loose electrical connections in Unit 3 and the material deficiencies identified in Unit 1 were not operability concerns, they were indications of poor material condition and inattention to detail. The licensee decided to discuss these problems with electricians and emphasize the need to perform detailed walkdowns after an outage to identify and correct these types of deficiencies. The inspector concluded that the licensee's response was appropriate.

3.3.1 High Energy Line Break (HELB) Analysis

The inspector reviewed the licensee's analysis of a HELB in the auxiliary building to verify that the loose electrical connections did not adversely impact the operation of safety related equipment during this event. The inspector noted that the licensee calculated a peak pressure in the mechanical penetration room of less than 3 psig from this event. The inspector reviewed the environmental qualification (EQ) program manual and noted that the licensee had done a study concerning the sealing requirements for electrical connections exposed to a HELB environment and determined that for accident

pressures less than 3 psig the connections do not need to be sealed to preclude moisture intrusion provided:

- The conduit and junction box systems connected to the equipment were designed to facilitate condensate drainage; and,
- The integrity of the equipment enclosure was maintained in accordance with the tested equipment configuration (e.g., use of proper cover torque and cover screw/o-ring and gasket configuration).

The inspector noted that the study included actual tests on various types of electrical enclosures to support the conclusions. The inspector concluded that the licensee's study supported its determination that the loose electrical connections in the auxiliary building were not safety significant.

The inspector conducted walkdown of the mechanical penetration rooms in the Unit 1 auxiliary building to determine if the electrical junction boxes had weep holes to provide for condensate drainage, and if the covers for the electrical devices (e.g., motors, transmitters, solenoids, etc) were appropriately secured and sealed. The inspector verified that the covers for the electrical devices were properly installed and that all the safety-related junction boxes had weep holes to allow for condensate drainage.

The inspector also noted that EQ engineering was conducting field verifications of the installation of electrical conduit in the auxiliary building to verify the assumptions used in the HELB analysis. The inspector concluded that EQ engineering had conducted a thorough, detailed evaluation of the effect of a HELB on the electrical components in the auxiliary building and that the licensee's actions to conduct field verifications were prudent.

3.4 Leaking Air Regulator for Atmospheric Dump Valve - Unit 1

On June 4, the inspector noted a buzzing noise from an air regulator associated with the pneumatic operator for Unit 1 atmospheric dump Valve (ADV) SGB-179. I&C technicians subsequently investigated the noise and determined that the air regulator appeared to have a leak past its diaphragm. The SS declared ADV SGB-179 inoperable and I&C technicians replaced the air regulator. Operators then satisfactorily performed a post-maintenance pressure drop test on the air system for the ADV and declared the ADV operable.

The licensee initiated CRDR 1-5-0145 to determine the cause of the leaking air regulator. The evaluation had not been completed at the end of the inspection. The inspector will review the licensee's evaluation when it is completed.

3.5 Emergency Operation Procedure Training

The licensee implemented its revised emergency operating procedures (EOP) at the end of the inspection period. The EOPs were revised to be consistent with Combustion Engineering owner's group guidance (CEN 152). The inspector observed portions of the "high intensity team" training conducted for each

crew in preparation for the implementation of the EOPs. The inspector observed one crew respond to a steam line break event and a steam generator tube rupture event.

The inspector noted that the EOPs enhanced crew performance and allowed for greater flexibility in responding to events. As an example, during the steam generator tube rupture event, the crew was able to isolate the faulted steam generator within 14 minutes from the start of the event. In contrast, during the March 1993 Unit 2 steam generator tube rupture event, operators isolated the steam generator in approximately three hours, in part due to restrictions in the EOPs used at the time.

The inspector observed good trainer performance in that they closely observed crew performance and performed detailed and critical post-scenario reviews. The inspector also interviewed several crews following the training and found that they were consistently pleased with the new EOPs. They found the procedures to be easier to use and allowed them to concentrate on plant performance.

3.6 Walkdown of EDGs - Units 1 and 2

On June 8, the inspector performed a walkdown of the Units 1 and 2 EDGs. The inspector noted that the housekeeping of the Unit 1 EDGs was adequate and that the housekeeping of the Unit 2 EDGs has greatly improved, especially in the area of the auxiliary skid.

The inspector noted that starting air cross-tie Valve DGN-V238 in Unit 1 on the Train A EDG was not in its normal position as indicated by plant procedures. The valve had been opened to keep both starting air receivers pressurized during air dryer maintenance. The change of the valve's normal position was not documented. The inspector discussed the valve position with the system engineer and determined that the valve was in the nonsafety-related portion of the system and that there was no safety significance in leaving the valve in the open position.

The inspector informed the Unit 1 operations department leader about the position of DGN-V238 and the inspectors concern for the configuration control of the valve. The operations department leader agreed that there was a configuration control weakness and attached a caution tag to the valve to ensure it was returned to the desired position upon completion of the maintenance. The inspector concluded that the licensee's response was appropriate.

3.7 EDG Governor Control Frequency - Unit 1

On May 23, the inspector observed that the Unit 1 Train A EDG was providing the only source of power to the vital 4160 volt bus, due to insulator repair on the associated startup transformer. The inspector noted that the EDG was operating in the isochronous mode at 60.8 hertz, and questioned the operators about the EDG frequency because the EDG usually operates at 60.0 hertz. The inspector was concerned that the operators had not questioned the EDG frequency and were unable to effectively respond to the inspector's concern that the observed indication may represent a problem or an unfavorable trend.

The inspector noted that a similar concern was raised in February, 1995 (NRC Inspection Report 50-528/95-03; 50-529/95-03; 50-530/95-03), when operators did not demonstrate a questioning attitude when they noted, but failed to investigate, an off-normal indication in safety injection line pressures. The inspector also noted that the licensee procedures being used to operate the EDG, 410P-1DG01, "Emergency Diesel Generator A," and 410P-1PB01, "4.16kV Class 1E Power (PB)," did not specify that the EDG should be operated at 60 hertz.

The inspector informed the EDG system engineer about the inspector's observation and questioned the performance of the woodward governor. The engineer investigated the EDG performance and responded that the governor was performing as designed. The inspector evaluated the engineer's conclusion, agreed that the EDG was performing as designed, and concluded that the engineer had responded quickly and thoroughly to the inspector's concern.

The inspector informed the operations department leader about the EDG observations and the licensed operator response. The operations department leader agreed with the inspector's concern, and issued a memo to all licensed operators emphasizing management's expectation for control board awareness and for the operators to monitor and question any abnormal indication. In addition, the operations department leader issued an instruction change request to change the 4.16kV Class 1E Power procedure in all three units to provide guidance on EDG frequency control. The inspector concluded that the operations department leader's corrective actions were appropriate.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 AFW System Governor Valve - Unit 1

On May 13 and May 15, the Unit 1 steam driven AFW pump turbine tripped on overspeed during uncoupled runs performed as part of postmaintenance testing. The postmaintenance testing was performed following the replacement of the valve stem and packing. The licensee observed that the governor valve failed to properly respond to control signals, resulting in the overspeed trips. The inspectors observed mechanical maintenance engineers disassemble the governor valve, interviewed maintenance personnel, reviewed the licensee's evaluation of cause, and assessed the licensee's planned corrective actions.

The licensee determined that the overspeed trip was caused by binding of the governor valve stem, which prevented the valve from stroking freely. The licensee determined that the binding resulted from deficiencies in the inner packing of the governor valve. The licensee speculated that the stuffing box had not been adequately filled, resulting in broken carbon spacers and cocked stainless steel washers. The licensee concluded that the improper assembly was caused by inattention to detail by the mechanical maintenance technicians.

The inspector concluded that the licensee had not been rigorous in its cause evaluation, and had not performed sufficient review to determine that packing deficiencies caused the valve to stick. Additionally, the inspector concluded that weak work instructions were a significant contributor to the packing deficiencies, and that there had been prior opportunities to enhance the work instructions.

4.1.1 As-Found Condition

The stuffing box for the governor valve contained the inboard and outboard valve packing assembly. The assembly provided a labyrinth seal with the combination of carbon spacers and stainless steel flat washers, followed by the guide bushing and the retaining ring.

Prior to disassembling the governor valve, mechanics attempted to move the valve stem. With the stem in a horizontal orientation (as installed), they could not move the stem. With the stem in a vertical orientation, the stem could be moved easily. Mechanical maintenance personnel subsequently disassembled the governor valve stuffing box on May 17, and found several of the carbon spacers broken in half, chipped and pulverized. In addition, the number of sets of carbon spacers and steel washers removed was determined to be one set less than the amount needed to completely fill the stuffing box.

The licensee measured the stuffing box and determined that 22 sets plus one extra washer was required to completely fill the stuffing box. The licensee repacked the stuffing box accordingly, and noted a gap of 0.025 inches between the guide bushing and the retaining ring. This gap was determined to be acceptable. The postmaintenance test was repeated and the governor valve responded appropriately.

4.1.2 Licensee's Apparent Cause Determination

The licensee determined that the governor valve had failed due to the stuffing box not being completely full. This allowed the packing assembly to have too much free play and the licensee speculated that this allowed the steel washers to become cocked. Additionally, when force was applied to the valve stem, the cocked steel washers placed additional friction on the carbon spacers, causing the carbon spacers to break. The licensee concluded that this would have explained why the valve stem locked up in the horizontal orientation and not the vertical orientation.

Additionally, one mechanical maintenance engineer noted that during a past packing job he had cocked one of the washers. This was discovered when he noted that there were washers and spacers left over when the stuffing box was full. This observation supported the licensee's conclusions that a cocked washer may have contributed to the inadequately full stuffing box.

The licensee determined that inattention to detail by mechanical maintenance personnel was the apparent cause of the failure to completely fill the stuffing box.

4.1.3 Licensee's Planned Corrective Actions

The inspector reviewed the licensee's proposed corrective actions described in the CRDR. The licensee planned to implement the following corrective actions prior to the next refueling outage:

- Enhancements to the master work instructions and preventative maintenance (PM) tasks to include more quantitative instructions on packing the valve.
- Additional training for proper assembly of the governor valve stuffing box using a mockup of the governor valve.

4.1.4 Inspector's Review of Cause Determination

The inspector questioned the state of the carbon spacers found in the past when disassembling the governor valve. Both the mechanical maintenance engineer and the maintenance technicians stated that it was common to find broken carbon spacers during valve disassembly. However, they noted that it had never caused the valve stem to bind. The inspector questioned whether the discovery of broken carbon spacers had ever been evaluated. The licensee determined that it had not.

The technicians also stated that the carbon spacers could be easily chipped or broken when the packing was assembled. The threads on the end of the valve stem may contain tiny burrs that may chip the inside diameter of the spacer during installation or removal. While the installation and removal of the carbon spacers could have resulted in some chipping, the inspector determined that this would not explain the amount of breakage observed during a typical disassembly. The inspector considered that the licensee had not been appropriately sensitive to previously observed carbon spacer deficiencies.

The inspector reviewed the PM task work order which controlled the original replacement of the valve stem and packing, and compared it with the instruction provided in the vendor technical manual (VTM). Both contained instructions for repacking the stuffing box assembly. The work instructions in the PM task, which duplicated the VTM instructions, stated in part:

> "Starting with a carbon spacer, alternate stacking the carbon spacer and flat washer until the stuffing box is full and the guide bushing and retaining ring can be installed. Use additional washers to finish filling the stuffing box. The complete stack should not be tight, some play is required".

The inspector questioned the mechanical engineer as to what the required amount of play was and what does it mean when the stuffing box was full. The engineer stated that it was common maintenance practice to fill the stuffing box until no further carbon spacers (0.125 inch thick) could be added, and then fill the remaining space with additional washers (0.062 inch thick).

As noted previously, the proper as-left gap was 0.025 inches. Using this value, the inspector determined that the as-found gap with one spacer and two

washers missing would be approximately 1/4 inch. The inspector questioned whether a 1/4 gap could be seen by the mechanics as providing a full stuffing box meeting the ". . .not tight, some play. . ." criteria. The mechanical maintenance team leader concluded that it would have been too loose. However, the team leader noted that the gap could have been measured between the last washer and the bushing. During the May reassembly it was noted that the bushing shoulder appeared to have eroded which allowed the bushing to set lower in the stuffing box, reducing the clearance between the bushing and last washer. This also increased the gap between the bushing and the snap ring.

The licensee discussed the various ways to measure the stuffing box gap with the vendor. The vendor noted that the total gap established was the critical dimension. The inspector concluded, however, that had the mechanics measured the gap between the bushing and the last washer, and not considered the gap between the bushing and the snap ring, they could have reasonably concluded that the stuffing box was full with some play.

The technicians stated that they were confident that they had packed the stuffing box in accordance with the work instructions. After the technicians assembled the valve, they checked for valve freedom of movement, as required by the work instructions. However, the technicians pointed out that there was no quantitative acceptance criteria for the valve's length of stroke. If a spacer had been cocked, it would have been possible for the stem to have some movement. The inspector considered that valve stroke length was a significant parameter which should have been included in the work instructions.

4.1.5 Evaluation of Licensee's Cause Evaluation Process

The inspector noted that the licensee considered this problem to be an "Adverse" condition, as identified by its CRDR process. The event was determined to not be "Significant," primarily due to the fact that it was discovered during postmaintenance testing and not while the pump was considered operable. Consistent with its program, mechanical maintenance did not perform a formal root cause evaluation, and planned only to identify an "apparent cause."

The inspector noted that while the classification of "adverse" was consistent with licensee procedures, it did not appear to be prudent, in that the licensee has experienced a significant history of AFW turbine overspeed events. Additionally, there have been several recent industry events highlighting concerns with the governor valve stem and its packing. Given these events and the risk-significance of the turbine driven AFW pump at Palo Verde, the inspector considered that it would have been prudent to have performed an in-depth root cause evaluation.

The inspector met with licensee maintenance personnel and management several times during the inspection period, and noted that maintenance personnel seemed to be learning new information from each other. In addition, the inspector consistently found new and sometimes conflicting information during followup inspection. It also appeared that plant management had a greater expectation of the cause evaluation than those at the working level and that these expectations had not been well communicated.

The inspector concluded that, although the evidence appeared to qualitatively support the licensee's conclusion that the stuffing box had been inadequately packed, these conclusions were not supported by rigorous quantitative evaluation, such as using mockups with a spare governor valve, or specific measurement of how much space was necessary to allow a washer to cock.

At the exit meeting, the Director of Maintenance agreed with the inspector that communications could be improved and that a more rigorous root cause evaluation should have been performed. The licensee also agreed to assess the adequacy of the CRDR process which lead the engineers to only conduct an apparent cause evaluation.

4.2 Leaking Safety Injection System Check Valve - Unit 1

On May 18, a high pressure safety injection (HPSI) system check valve in Unit 1, SIA-V113, failed a postmaintenance reverse flow seat leakage test. SIA-V113 was a 3-inch Borg Warner swing check valve and functioned as the inside containment isolation valve for the HPSI injection line to reactor coolant Loop 2B. The reverse flow seat leakage test was required after the valve was disassembled and inspected on April 13.

The licensee subsequently disassembled SIA-V113 to determine the cause of the excessive seat leakage. The licensee determined that the bonnet assembly was installed too high which resulted in the valve disc not being centered in the valve seat. On May 22, the licensee aligned the valve disc and seat, and SIA-V113 passed the postmaintenance seat leakage test. The licensee initiated a CRDR to determine the cause of the leakage and to identify appropriate corrective actions.

The inspector reviewed the model maintenance procedure for disassembly and reassembly of Borg Warner check valves, reviewed the VTM, and had several discussions with the check valve engineer. The purpose of this inspection was to determine if the model maintenance procedure was adequate to detect and correct a check valve alignment problem.

4.2.1 Vertical Alignment Determination

The inspector noted that the check valve maintenance procedure required the mechanics to measure and record the distance from the top of the seat retaining ring to the valve body prior removing the check valve internals. This measurement was recorded as the as-found Dimension A. When the valve was reassembled, the procedure required the mechanics to thread the seat retainer into the valve body until the as-left Dimension A was the same as the as-found Dimension A. The inspector noted that using this procedure ensured that the valve disc was reinstalled in the same vertical location on the valve seat.

The inspector noted that Appendix D of the procedure included instructions for determining if the valve disc was centered on the valve seat. Using these instructions the mechanics could measure the distance from the top of the valve body to the center of the valve seat and the distance from the top of the valve bonnet to the center of the valve disc, and then calculate an

as-left Dimension A that would ensure the valve disc was centered in the valve seat.

The licensee was required to perform the alignment check in Appendix D if the results of previous seat leakage tests were higher than normal, or if there were abnormal wear marks on the valve seat during the check valve inspection. The licensee did not perform the Appendix D alignment check prior to reassembling SIA-V113 because the last reverse flow test was well within the acceptance criteria and there were not any abnormal wear indications on the valve disc and seat.

The inspector concluded that the licensee had complied with the applicable check valve maintenance procedure. The inspector also concluded that, prior to the observed valve leakage problem, and based on the licensee's previous trouble-free experience with these valves and existing vendor manual guidance, the procedure requirements for ensuring proper valve assembly appeared to have been reasonable. However, based on the observed problem, the inspector concluded that additional procedure guidance to ensure proper valve assembly was warranted.

4.2.2 Corrective Actions

The licensee determined that differences in measuring the Dimension A contributed to the valve bonnet for SIA-V113 being set higher than other similar check valves. The licensee subsequently disassembled SIA-V113 and calculated a new Dimension A using Appendix D. The licensee reassembled the valve and set the vertical alignment using the new Dimension A and the valve successfully passed the reverse flow test.

The licensee initiated an evaluation of whether Appendix D should be performed to verify the proper vertical alignment of the check valves as part of every check valve inspection. The licensee also planned to disassemble a spare check valve and determine an optimum method to measure the dimensions used to center the valve disc and seat.

The inspector concluded that these corrective actions were appropriate. However, the inspector was concerned that the licensee's initial corrective actions did not include an appropriate acceptance criteria for when the vertical alignment of the valve would be adjusted based on the calculated Dimension A using Appendix D. The inspector discussed this concern with the check valve engineer who agreed to include an action to quantify this acceptance criteria. The inspector concluded that the licensee's response was appropriate.

4.3 Instrumentation and Controls (I&C) Technicians Working on Wrong Valve - Unit 1

On March 23, 1995, while in containment to perform work on pressurizer spray Valve 100E, an I&C technician tightened a jam nut on the booster relay for the valve, resulting in spurious closure of the valve. Since spray Valve 100F was the valve in service maintaining RCS pressure, its closure caused RCS pressure to increase to 2274 psia. Operators had been maintaining the spray valve open with pressurizer heaters on to provide boric acid equalization between the RCS

and the pressurizer. Operators were alerted to the condition by a control room alarm and stabilized RCS pressure by turning off pressurizer heaters.

The I&C technicians returned to the control room and were questioned by the operators as to what work they had performed and whether it could have impacted Valve 100F. The I&C technicians stated that they had tightened the jam nut and recognized that an associated adjustment screw may have turned with the nut. I&C technicians returned to containment and readjusted the jam nut, restoring the operation of the spray valve. After the event, the SS initiated CRDR 1-5-133.

The inspector discussed this work with the I&C department leader, section leader and team leader. They noted that there was an open work order for the spray valve covering the proper adjustment of the booster relay. They stated that the technicians had not anticipated that tightening the jam nut would have turned the adjustment screw. However, they concluded that it would have been appropriate for the technicians to inform the control room prior to performing the adjustment and they subsequently counselled the technicians. I&C management also discussed lessons learned from this event with I&C personnel. The inspector found these actions to be appropriate.

4.4 Wrong Torque Values Used on Unit 1 and 2 Spray Valves

During the Unit 1 refueling outage, the actuators of both RCS spray valves were replaced with larger actuators. In addition, the body to bonnet gaskets were replaced. The gasket for RCS spray Valve RCE-PV-100E began to leak as RCS pressure was increased during the Unit restart. Mechanical maintenance increased the body to bonnet bolt torque by 10 percent in an attempt to stop the leakage. When the leakage failed to stop, the licensee discovered that the bolt torque used was significantly lower than the appropriate torque value for valves in this service.

The licensee took concurrent actions to perform calculations to determine appropriate torque values and to contact the vendor, Fisher Controls. The initial torque value had been 130 ft-lbs. The licensee initially calculated a torque value of 345 ft-lbs. The vendor subsequently recommended a torque value of 540 ft-lbs. The licensee applied its calculated torque values to both Unit 1 spray valves. In addition, the licensee entered both Units 2 and 3 containment buildings with the units at full power to retorque the spray valve body-to-bonnet bolts. They noted bolt movement in the Unit 2 valves, which had been modified during a February 1995 refueling outage. However, no bolt movement was noted in Unit 3.

4.4.1 Cause Review

The licensee determined that the following factors contributed to the inadequate torque of the Units 1 and 2 spray valve body to bonnet bolts:

- The licensee index for the Fisher Controls VTMs referenced the wrong manual for the spray valves. The referenced VTM covered a similar valve body model, rated for 600 psi service, which required only 130 ft-lbs torque. The licensee concluded that an error was made when the VTM

index was created. They speculated that a note in the vendor drawing for the valve contributed to confusion in that it indicated the valve weight of 600 lbs.

- Fisher Controls identified during its discussions with the licensee that the spray valves were 4 inch bodies with 3 inch ends. The vendor drawing did not indicate this fact. The licensee subsequently found that a purchase specification did confirm that the spray valves were 4-inch bodies. The vendor body to bonnet torque specification for 4-inch bodies was 540 ft-lbs versus 404 ft-lbs for 3-inch valves. Licensee work records indicated that prior to the development of the VTM index, the valves had been torqued to 404 ft-lbs.

- Fisher Controls identified that the 540 ft-lbs specified for the 4-inch valves was a maximum torque value to use in problem valves. The licensee confirmed this with its own calculations in that torque values this high could produce high bonnet stresses. The licensee determined that optimum bolt torque would be between 350 and 405 ft-lbs.

- A chance to identify these problems was missed during the Unit 2 outage. One of the Unit 2 spray valves had initially leaked after having been torqued to 130 ft-lbs. It was subsequently torqued to 143 ft-lbs and stopped leaking.

The inspector discussed the licensee's findings with maintenance engineering and found them to be appropriate.

4.4.2 Safety Significance of As-Found Condition

The licensee identified that Unit 2 had operated for greater than 30 days with the low spray valve body to bonnet bolt torques. They performed an as-found condition calculation to determine whether there had been sufficient preload on the bolts to prevent cyclic stresses during all operational conditions. The calculation, which considered temperature, pressure, and seismic influence, determined that while a substantial amount of preload could be lost, sufficient joint compression remained. Additionally, the licensee evaluated the potential for loss of gasket crush to determine the potential maximum body to bonnet leakage. They calculated that the maximum leak would be a fraction of the makeup capacity for one charging pump.

The inspector reviewed the scope of the calculations and the calculation assumptions and found that they were appropriate.

4.4.3 Corrective Actions

The licensee initiated plans to re-torque all bolts to 375 ft-lbs. This was completed in Units 1 and 3 with plans to torque Unit 2 bolts in early July.

The licensee initiated an action to revise the VTM and appropriate drawings to reflect the results of its investigation. In addition, the licensee had asked the vendor to clarify its conclusion that the torque values for the spray valves as indicated in the VTM were maximum values. This was not clear in the

VTM and could have an impact on the torque applications for other valves. The inspector will follow the licensee's evaluation during routine inspection.

The inspector found that although the licensee had initially missed the opportunity to identify these problems in Unit 2, the subsequent corrective actions were appropriate. The licensee's review of the issue and the response to deficiencies were thorough and prompt.

4.5 Spent Fuel Pool Spacer Removal - Unit 3

On June 13, the inspectors observed refueling and maintenance services (RAMS) personnel remove spent fuel rack blocking plates from the spent fuel pool. This design change would modify the current checkerboard mode of storage to a different storage mode to allow for more fuel assembly storage space.

The inspector noted that the work package was not present at the work site. The inspector questioned one of the RAMS personnel and was told that the work package was back in the RAMS office. The inspector went to the office to review the work package. The inspector noted that the work was being performed in accordance with the work instructions however, not having the work package in the field could lead to procedure noncompliance problems.

The team leader stated that the inspector's observation did not meet management's expectations. The inspector reviewed the "Principles of Maintenance" issued by management and noted that, principle number 2 states, "maintain the work document/procedure at the work site. . ." The inspector noted that a previous example of work being performed without the work package in the field was documented in NRC Inspection Report 50-528/95-10; 50-529/95-10; 50-530/9510, Section 4.2. The inspector was concerned that these examples may indicate a need to emphasize management's expectations for the use of work packages in the field.

The inspector noted that the licensee had initiated an evaluation of procedures to determine the need to emphasize management expectations or to provide appropriate guidance for the use of work orders in the field. The licensee planned to present these expectations to all maintenance personnel. The inspector concluded that the licensee's response was appropriate.

4.6 Feedwater Heat Exchanger Leak Repair - Unit 3

On June 6, the inspector observed mechanical maintenance technicians repair tube leaks identified on Feedwater Heat Exchanger 1A. The inspector noted that the technician did not have an oxygen monitor inside the heat exchanger. Sometime later, another technician obtained the oxygen monitor and gave it to the technician working inside the heat exchanger.

The inspector reviewed the procedure for confined space entry and its requirements for an oxygen monitor and discussed the requirements with the maintenance team leader responsible for the job. The maintenance team leader stated that there was no immediate threat or danger to the technician inside the heat exchanger since there was continuous ventilation provided by a portable blower, but he was unsure of the requirement to have an oxygen monitor.

The inspector discussed the concerns with nuclear assurance and the maintenance section leader. The oxygen monitor was not required because the feedwater heat exchanger was classified as a non-permit required confined space area, however, the maintenance team leader was unsure of the classification. The inspector concluded that although the oxygen monitor was not needed in this case, it was apparent that the confined space requirements were not well understood by the acting team leader when challenged by the inspector. The licensee discussed requirements concerning confined space areas with all of the maintenance crews. The inspector concluded that the licensee's response was appropriate.

5 SURVEILLANCE OBSERVATION (61726)

5.1 Safety Injection System Check Valve Leakage Testing - Unit 1

On May 23, the inspector observed the licensee perform portions of Surveillance Test 73ST-9SI03, "Leak Test of SI/RCS Pressure Isolation Valves". The purpose of the test was to satisfy surveillance Requirement 4.4.5.2.2 of Technical Specifications by verifying that SI/RCS check valve leakage was within limits.

The inspector noted that the licensee did not perform the procedure as written. Specifically, the licensee did not install the drain rigs in accordance with the procedure and did not drain the water from the 3-inch headers upstream of check Valves SIA-V523 and SIB-V533, as directed by the procedure. Instead, the licensee installed the drain rigs with a loop seal to keep the headers full. The failure of the licensee to follow procedures is a violation of TS 6.8.1 (Violation 528/9512-01).

The inspector informed the CRS about the observations. The CRS discussed the procedure performance with the test director. The CRS noted in the surveillance test log that the test director had chosen not to perform the procedure as written due to difficulty in draining and subsequently refilling the header, which did not include a vent valve in that section of pipe. The CRS noted that the test was performed for 10 minutes, no leakage was noted, and, therefore, the one gpm limit was not exceeded.

The inspector questioned the licensee about the performance of the surveillance test. The licensee initiated a CRDR to evaluate the technical adequacy of the method used by the test director. Engineering calculated the volume of the pipe and hose, used worse case conditions by assuming that the piping was initially empty, and calculated that to fill the piping and hose in a 10-minute period, the leak rate past the check valves would be 0.66 gpm. Accordingly the licensee concluded that the check valve leakage did not exceed the TS limit of 1.0 gpm.

The inspector discussed the performance of the test with the test director and reviewed the test director's statement about the event. The inspector noted that the test director thought that the procedure had been changed to place a loop seal in the drain hose and was not aware of the actual requirements of Appendix D.

The licensee discussed with the test director the expectation for procedure use as well as the conduct of complete and accurate prejob briefings. In addition, the licensee submitted an instruction change request to revise the Appendix D leak rate testing method. The licensee indicated that the change would be incorporated prior to the next use of the procedure during the Unit 3 refueling outage.

The inspector concluded that the safety significance of the failure to follow the procedure was low. However, the inspector concluded that the test director did not refer to the procedure prior to or during performance of the test and, as a result, made incorrect assumptions about the requirements of the procedure.

5.2 Other Surveillance Observations

The inspectors observed the following surveillance test and determined that it was performed acceptably:

- EDG A Monthly Surveillance Test - Unit 3.

6 ONSITE ENGINEERING (37551)

6.1 EQ Life of S/G Blowdown Isolation Valves

During a routine tour of the mechanical penetration room of the Unit 2 auxiliary building, the inspector noted that the steam generator blowdown line sample valves were continuously energized Valcor solenoid operated valves (SOVs), and were in contact with hot process fluid. The inspector noted that the licensee had previously identified solenoid valves in similar applications where the service temperatures of the solenoids were higher than the temperatures used in the EQ test report used to qualify the solenoids.

The inspector asked the EQ engineering group to identify the critical components of the Valcor SOVs, the temperatures used in the qualification test report for these components, and the service temperatures of these components. The licensee was aware that these valves were susceptible to potential hot spots, but they had not previously compared actual field conditions to the assumptions in the EQ binder. In response to the inspector's questions, the licensee reviewed the EQ binder, determined the qualified temperatures of the critical components, and took inservice temperature readings of these components. The licensee concluded that the service temperatures of the Valcor SOVs were much lower than the temperatures used in the qualification report and that there was not a safety concern with the valves.

The inspector was concerned that the licensee had not yet determined which EQ components were the most susceptible to hot spots from process fluid heating, and evaluated these components to determine if there was a qualification concern for these components. The inspector reviewed the licensee's thermal monitoring program in NRC Inspection Report 50-528/95-10 and noted that the licensee measured field temperatures of target rock SOVs and Namco limit switches in the main steam support structure, and verified that the qualified life of these components were appropriate.

The inspector discussed this concern with the supervisor of EQ engineering and noted that the licensee had identified five components that were a potential concern during the process of developing the scope of the thermal monitoring program. The licensee had previously taken temperature readings on two of these components, Target Rock SOVs and Namco limit switches, because of actual performance problems. The licensee revised the EQ life of these two components as a result of these reviews. The licensee evaluated the Valcor SOVs in response to the inspectors questions. The licensee had not measured service temperatures to validate the EQ life of the remaining two components, Asco and Skinner solenoids.

The inspector asked the EQ engineering supervisor why they had not performed a preliminary assessment of all the components susceptible to hot spots in the main steam support structure, the auxiliary building, and in the containment building. The EQ supervisor stated that they planned to monitor the temperatures of the Valcor SOVs and the Asco and Skinner solenoids later in 1995, when the formal thermal monitoring program was implemented. The licensee made this decision primarily because there had been no performance problems with these components.

The inspector concluded that the licensee was shortsighted by only using known performance problems as the criteria for validating the service temperatures of these components. The inspector based this conclusion on the fact that the absence of known performance problems does not mean that a component with a qualified life will perform adequately during a design basis event. The inspector also concluded that the licensee should have validated the service temperatures used to qualify these components as an interim corrective action, prior to implementation of the formal thermal monitoring program.

The inspector discussed this observation with the EQ section leader who agreed with the inspector that a preliminary assessment of all the susceptible components would have been appropriate and committed to measure the service temperatures of a representative sample of the remaining components and evaluate the adequacy of its qualified life. The inspector concluded that these actions were appropriate.

6.2 Cracking in RCS Sample Valves

In January 1994, the licensee identified internal cracks in the bodies of RCS hot leg sample valves in Unit 2 (NRC Inspection Report 50-529/94-02). The two solenoid operated sample valves, supplied by Valcor, were the inside and outside containment isolation valves for the RCS hot leg sample line. The valves were removed and replaced. The licensee had contracted with the Southwest Research Institute laboratories to perform failure analysis and metallurgical inspection.

The valves are constructed from a 4-inch block of stainless steel with inlet and outlet penetration ports. The valve internals are threaded and seal welded into an approximate 2-inch diameter, 2-inch deep cylindrical bore. The cracks, identified when the internals had been removed for inspection, formed along the base of the cylindrical bore and along the inlet port. The cracks were not through-wall.

The failure analysis indicated that the cracking had resulted from low cycle thermal fatigue. The valves had seen approximately 3000 to 5000 cycles of ambient to 600°F temperature changes. The failure analysis concluded that the valves would have remained functional for over 20 years in that service environment.

The licensee reviewed industry data and discussed the findings with the valve vendor but did not identify any similar instances of cracking. The licensee documented the results of their findings in Nuclear Plant Reliability Data System.

The licensee inspected Units 1 and 3 RCS sample valves during the respective refueling outages, and discovered similar cracking in the hot leg sample valves. In addition, the licensee discovered cracking in the inside containment pressurizer steam space sample valves in both Unit 1 and Unit 3. These valves had been subjected to fewer thermal cycles, and the cracking was less pronounced. The inspection and replacement of the Unit 1 valves was completed in May 1995.

Since the initial finding, the licensee has initiated studies to determine long term corrective actions to eliminate the stresses which cause cracking. The licensee had worked with the vendor to perform postfabrication changes to the valves to reduce thermal stresses, such as reducing the mass of the valves. Additionally, the licensee has explored installing a heat exchanger upstream of the valves to reduce the magnitude of thermal cycling. At the end of this inspection, the licensee had not identified a long-term solution. Currently, the licensee intends to replace existing valves at a frequency consistent with the rate of crack propagation.

Although the licensee's initial survey would indicate that this issue may be isolated to Palo Verde, it would appear that these model valves are used in similar applications at other sites. The licensee informed the inspector that they would issue a notice to other sites on a industry information network.

6.3 Potential for Auxiliary Feedwater Pump Trip Following an Excess Steam Demand Event

In March 1995, the licensee identified, during a modification review of the AFW turbine driven pump, that under certain conditions following an excess steam demand (ESD) event, such as a steam line break, operators could unintentionally cause the pump to trip. In addition, they identified the possibility that during some steam line break events an automatic actuation could cause the pump to trip. The licensee's evaluation was documented in CRDR 9-5-0200.

Following an excess steam demand event, level in the faulted steam generator could drop to the auxiliary feedwater actuation signal (AFAS) level for the generator. For a moderate break, the AFAS in the faulted generator would initiate a start of the AFW turbine driven pump by opening a steam supply from the faulted steam generator. At some point, operators would have to transfer the steam supply from the faulted generator to the intact steam generator to provide continued AFW turbine operations. The licensee determined that it was

likely that if the transfer was done without resetting the AFW turbine governor logic, the AFW turbine would trip on overspeed.

Prior to the transfer, the turbine governor valve would be open wide to allow the relatively low pressure steam of the faulted generator to maintain turbine operation. If the nonfaulted steam supply was opened without resetting the governor valve to maintain a lower speed, the governor valve would not have time to compensate before the turbine reached the overspeed setpoint. The licensee used the operator training simulator to verify the possibility of this event.

The circumstances would not occur on a larger ESD, since a differential pressure lockout of an AFAS would actuate before the AFAS signal. On a smaller ESD, steam line pressure would not degrade to the point a transfer would cause a turbine overspeed event.

The steam supply transfer can be accomplished successfully if the faulted steam supply valve is closed before the nonfaulted steam supply is opened. This sequence causes the governor logic to reset and demand a lower speed. The licensee took action to cover this change in operator training, procedures, and EOP implementation. The inspector observed the implementation of this training during EOP training and found it to be appropriate.

The licensee identified that there was the possibility that a design basis event could cause the failure of the AFW turbine driven pump. The design basis requires that no operator action can be assumed to take place for the first 30 minutes. The ESD would have to be of a magnitude such that the AFAS on the faulted generator occurred before the differential pressure lockout, and an AFAS on the intact generator occurred within 30 minutes. Although considered to be highly unlikely, licensee engineers were able to cause this to occur on the plant simulator for a steam line break of approximately 22.5 percent of full power.

The licensee initiated a more detailed study of the event to determine the probability of the event. The inspector noted that these studies were scheduled to be completed at the end of July 1995 and found this to be appropriate. The inspector will follow the results of the analysis in a future inspection. The inspector discussed this issue with licensee management and noted that they should keep in mind the potential generic aspects of this event.

6.4 Target Rock Valves with Weak Springs

During a routine review of an industry events bulletin, the licensee found that Target Rock Corporation, a vendor of solenoid operated valves, had identified that some valve springs had been provided to Entergy Operations for the River Bend site which did not meet Target Rock's spring force specifications. The licensee contacted Target Rock and determined that the valve springs from the same lot had been delivered to Palo Verde as replacement parts. The valve springs, which assist solenoid valve closure, were provided by a sub-supplier for 1 and 2-inch valves.

Target Rock had performed testing which identified that the lower spring forces did not affect the operation of the solenoid valves at River Bend. However, following discussions with Arizona Public Service, Target Rock initiated site-specific testing to determine whether the lower spring forces would have an impact at Palo Verde. At the end of the inspection period, the study had not been completed; however, the licensee had a high degree of confidence that the lower spring force would be determined to be adequate for the Palo Verde applications.

In the interim, the licensee identified ten safety-related installed valves which could potentially have the suspect springs and performed an operability determination, which concluded that the installed valves had either been satisfactorily tested at design basis pressures, or did not have a design function to close. In addition, replacement springs in the warehouse were quarantined. The inspector reviewed the operability determination and found it to be appropriate. The inspector will review the assessment of the valve springs by the vendor when it becomes available.

7 FOLLOWUP - OPERATIONS (92901)

7.1 Violation 530/9413-02 (CLOSED): Circuit Breakers Not Properly Racked Out

This violation occurred when the inspector observed various circuit breakers which were not racked out in accordance with operating procedures and, as a result, may not have been seismically restrained. The licensee's corrective actions included revising circuit breaker operating and maintenance procedures to define appropriate breaker positions and to require that the control room be informed of final breaker status after racking operations. The licensee's training department also developed job performance measures for breaker racking operations, and this event was reviewed with operators. The inspector reviewed the licensee's root cause evaluation for this violation, the operating and maintenance procedure changes, and the job performance measures. The inspector found the licensee's corrective actions to be adequate. During plant walkdowns, the inspector observed that breakers were properly positioned.

8 FOLLOWUP - MAINTENANCE (92902)

8.1 Follow up Item 529/9437-01 (Closed): Multiple Emergency Diesel Generator Trips

This item involved several nonsafety-related trips of the Unit 2 Train B EDG between December 14 and 16, 1994. The inspector was concerned that inappropriate maintenance may have contributed to some of the trips and that the EDG was unavailable for over 20 hours for repair. This item was opened to review the licensee's root cause evaluation and corrective actions.

The licensee performed a root cause investigation of this event and determined that the EDG tripped twice during the start sequence, twice during the cooldown cycle, and failed to stop once. The licensee determined that one of the trips was caused by a high resistance contact in a continuously energized Agastat relay, two of the trips were caused by leaking check valves, and one of the trips was caused by a leaking temperature control valve. The failure

to stop was caused by the installation of capillary tubing during troubleshooting activities that subsequently restricted air flow to the shutdown valve.

8.1.1 Corrective Actions

The licensee determined that the leaking check valves were caused by pieces of teflon tape that were caught on the valve seat. The licensee determined that the debris was introduced during the troubleshooting efforts. The licensee already had corrective actions in place to replace the check valves with a new design that had an internal filter and a stronger spring to minimize the leakage from the valve. In addition, the licensee conducted a training class on EDG troubleshooting and emphasized the importance of maintaining system cleanliness. The licensee also discussed appropriate precautions when installing test equipment during troubleshooting activities during the training class.

The licensee determined that the leaking temperature control valve was not identified during installation because the procedure did not require the valve to be leak tested after the valve was calibrated. The licensee updated the calibration procedures to require the valves to be leak tested. The licensee also had corrective actions in place to replace all continuously energized Agastat relays during the Unit 2 outage in March 1995.

The inspector concluded that the licensee conducted a thorough root cause evaluation and identified appropriate corrective actions to reduce the amount of nonsafety-related EDG trips.

8.1.2 Additional EDG Trips

On June 7, the Unit 2 Train B EDG tripped during a surveillance test run due to a faulty low turbocharger lube oil pressure relay. This relay was replaced during the last outage in March 1995 as part of the corrective actions listed above and was found to have an internal fault which caused the relay to open. On June 8, the Train B EDG tripped during a postmaintenance test run after installation of a new low turbocharger lube oil pressure relay. The licensee initially suspected an intermittent problem with some of the continuously energized relays in the shutdown circuit. The technicians checked three of the most probable relays and did not identify any high resistance contacts. The inspector observed the troubleshooting efforts and verified that the relays had been replaced during the last outage in March 1995. The inspector also noted effective interaction between the technicians, the maintenance engineer, and nuclear assurance evaluator during the troubleshooting activities, and that the procedure specified appropriate acceptance criteria for replacing the relays.

The licensee determined that the June 8, EDG trip was caused by a broken contact on the base of the low turbocharger lube oil pressure relay. The licensee determined that when the new relay was installed it was inserted and removed several times into the relay base until good contact was made. The relay base also needed to be filed to allow good contact between the relay and the base. The licensee believed that during these repairs the base of the

relay was damaged. The licensee subsequently replaced the relay base and the Train B EDG was satisfactorily tested.

The inspector concluded that although the licensee had reduced the number of nonsafety related EDG trips, the problems with relay bases highlighted the need for continued attention to the maintenance of the nonsafety related EDG control system. The licensee initiated another CRDR to evaluate the cause of the relay problems. The inspector will monitor the adequacy of the licensee's corrective actions.

8.2 Unresolved Item 528/9434-03 (Closed): Poor Work Orders on Target Rock Valves

This item involved the adequacy of a work order used to disassemble, reassemble, and set the stroke of certain Target Rock solenoid-operating valves. Specifically, the inspector questioned the quality of the work order in that mechanics had to rely heavily on the vendor technical manual instructions for setting the stroke of the valve. The inspector's observations were similar to earlier observations documented in NRC Inspection Report 50-530/94-26, for which the licensee had initiated an action to revise the work order.

The inspector reviewed Model Work Order 002002 for the disassembly, rework, and reassembly of Target Rock Model 76HH-008 solenoid-operating valves. The inspector found that the revised work order included more vendor technical manual information for setting the valve stroke than the previous work order. However, the inspector noted that mechanics would still need to refer to the vendor technical manual for the adjustment of disc-to-bonnet Clearance A, as the work order did not define the clearance, and earlier work order steps defined a different Dimension A. The inspector also found that partial disassembly of the valve internals was required to obtain a disc-to-body Measurement B, although the work order steps did not specify disassembly, and previous work order steps completed the assembly of the internals. Finally, the inspector found that one work step did not list part reassembly in a logical sequence, and that some work order steps referred to valve part numbers specified in drawings while other steps did not identify the part numbers. The inspector concluded that the revised work order was usable but could still be improved.

The inspector discussed the work order comments with a valve services engineer, who acknowledged the comments and indicated that valve services was working with mechanics to review and revise the model work order.

9 FOLLOWUP - ENGINEERING/TECHNICAL SUPPORT (92903)

9.1 Unresolved Item 530/9503-01 (CLOSED): Operability Evaluation of Essential Cooling Water

Inspection Report 50-530/95-03 identified that the licensee had not completed an evaluation of the operability of the ECW system during a period between 1992 and April 1994 for the impact of a seismic qualification deficiency.

The ECW system was initially designed to rely on the seismically qualified condensate transfer (CT) system to provide makeup from the condensate storage tank. The ECW process radiation monitors and associated instrumentation were not seismically qualified. Initial design calculations demonstrated that the CT system would provide sufficient makeup to the ECW system following a seismic event which ruptured the instrument lines.

In 1992, for a number of reasons discussed in NRC Inspection Report 50-530/95-03, the licensee disabled the CT system makeup to the ECW system. However, until April 1994, the licensee left the ECW radiation monitors in service. Therefore, during this period, if the nonseismically qualified instrument tubing had failed following a seismic event, the ECW surge tanks for both trains could have drained and the ECW pumps could have lost net positive suction head.

The licensee recognized in April 1994 that the condition was potentially reportable under 10 CFR 50.73. However, at the time of IR 50-530/95-03, the licensee's evaluation had not been completed. The evaluation was dependent on an assessment of the ability of the nonseismically qualified radiation monitor instrument tubing to withstand a seismic event.

The licensee made a 4-hour nonemergency report to the NRC in accordance with 10 CFR 50.72 on June 22, concluding that the system was not seismically qualified. However, this conclusion was made based on field walkdowns that indicated that the installed configuration of the radiation monitor instrumentation did not meet installation specification. The licensee subsequently performed computer modeling of the as-found configuration of the instrumentation, which demonstrated that actual stresses would have been significantly lower than code allowable stresses. The 10 CFR 50.72 report was retracted on June 29, after computer modeling was completed. The inspector reviewed the bases of the licensee's evaluation and found them to be appropriate.

9.2 Unresolved Item 528/9437-02 (Closed): Main Steam Safety Valve (MSSV) Information Notice

This item involved the licensee's response to information notice (IN) 94-61, "Potential Overpressurization of Main Steam System", issued on August 22, 1994. Unit 1 was operating at 98 percent power with two MSSVs inoperable, as allowed by TS 3.7.2, when the licensee received IN 94-60. The licensee did an initial review of the IN as part of a TS submittal to allow Unit 1 to return to 100 percent power with the two inoperable MSSVs. The licensee concluded that the concerns identified in the IN did not affect the amendment request, and on December 14, the TS amendment was approved and Unit 1 returned to 100 percent power.

The inspector reviewed the licensee's evaluation and had additional discussions with nuclear fuels engineering personnel. Based on these discussions, the inspector had the following observations:

- The licensee reviewed the specific concern discussed in the IN and found that Combustion Engineering, Inc. (CE) made the same assumption of a

linear reduction in power with inoperable MSSVs. The licensee subsequently used the existing CE simulation and modeled the specific core conditions in Unit 1 with one MSSV inoperable per SG and found the peak secondary pressures were acceptable.

- The IN stated that the potential for problems was greater at lower power levels, since there was more time to add heat to the secondary before a reactor trip occurred. The licensee reasoned that since Unit 1 was returning to 100 percent power, the concerns in the IN were not applicable to the TS amendment.

The inspector subsequently concluded that the licensee adequately addressed the concerns in the IN prior to the Unit 1 TS submittal for raising power to 100 percent.

In December 1994, the licensee conducted a preliminary analysis of the concerns in 94-60 and determined that operating with one or more MSSVs inoperable may cause overpressurization of the secondary system. The licensee also determined that CE's analysis of the loss of condenser vacuum accident, used to allow operation at 100 percent power with one inoperable MSSV, did not explicitly analyze the secondary side pressure with the most conservative parameters of the TS.

The licensee subsequently performed a detailed evaluation of the secondary pressure overpressurization event using the actual core conditions in Unit 1 at 100 percent power with one inoperable MSSV in both SGs. The licensee determined that the actual conditions in Unit 1 did not result in exceeding 110 percent of the design maximum secondary pressure. The inspector concluded that the licensee had performed an adequate evaluation to determine the potential problem with the CE simulation.

The inspector noted that the licensee conducted additional calculations of all the possible combinations of inoperable MSSVs and the actual and projected core conditions of all three units and found that the peak secondary pressures were acceptable. However, the licensee determined that a modification to the TS for inoperable MSSVs was required to ensure that the actual core moderator temperature coefficient was negative. The inspector concluded that the licensee's corrective actions were appropriate.

9.3 Deviation 528/9431-07 (CLOSED): Boric Acid Program Commitments Not Followed

This deviation occurred when the licensee's boric acid prevention program did not incorporate Generic Letter 88-05 commitments to list potential leak locations in procedures. The inspector reviewed Revision 8 to Procedure 73TI-9ZZ13, "Visual Examination for Leakage," and found that the licensee added Appendix B to the procedure to provide a boric acid walkdown checklist with walkdown attributes and specific locations where leakage could cause degradation of the reactor coolant system pressure boundary. Subsequently, the licensee issued Procedure 70TI-9ZC01, "Boric Acid Corrosion Prevention Program," which further defined program requirements and the list

of potential leak locations. The inspector concluded that the licensee's corrective actions were appropriate.

10 ONSITE REVIEW OF LICENSEE EVENT REPORTS (LERs) (92700)

10.1 (Open) LER 528, 529, 530/93-011, Revision 1: Potential Safety-Related Equipment Problems Due to Degraded Grid Voltage and (Open) LER 528/95-01, Revision 0: Entry Into TS 3.0.3 Due to Degraded Voltage

10.1.1 Licensee's Reports

LER 93-011, Revision 1, was issued February 6, 1995, and noted that a previously unanalyzed condition could occur due to low grid voltage. The unanalyzed condition involved double sequencing of safety-related pumps during an accident. Following an emergency safety features actuation, the licensee noted that the potential existed to not only start sequencing safety-related equipment onto preferred offsite power, but also to initiate load shedding due to the Class 1E 4.16kV undervoltage relays dropping out and not resetting, and then resequencing the equipment onto the emergency diesel generator.

The licensee stated in LER 93-011, Revision 1, that if grid voltage was kept above 99.5 percent, its calculations indicated that the double sequencing would not occur. The licensee also discussed long term corrective actions and stated that pending completion of these actions the grid would be kept above 100 percent. However, on February 15, 1995, the licensee entered TS 3.0.3, due to grid voltage falling below 100 percent during planned switchyard evolutions. The licensee and Energy Control Center (ECC) personnel restored the voltage by increasing the reactive voltampere (VAR) output of the main generators at the site. The licensee issued LER 95-001, Revision 0, on March 15, 1995, to report the February 15, 1995, occurrence.

10.1.2 Licensee's Actions

The licensee determined that its corrective actions for LER 93-011, Revision 1, had not been effective to maintain grid voltage above 100 percent. The licensee provided further instructions and guidance to its control room operators and to personnel in the ECC in Phoenix, who control the Palo Verde grid. The licensee also issued a new procedure for operator actions in response to a degraded grid and added degraded grid voltage to the Unit 1 Plant Monitoring System displays. The licensee stated that the following long term corrective actions would make all three units operable above 98 percent grid voltage.

- Removal of loads from Unit 1, the most heavily loaded unit
- Addition of an accurate grid voltmeter in Unit 1, so licensed operators will have ability to routinely monitor grid voltage
- Transformer upgrades and sequencer changes
- Automatic block of fast bus transfer

10.1.3 Inspector's Actions During the Present Inspection

The inspector reviewed both LERs, the licensee's procedure for response to degraded grid voltage, the licensee's review of the potential for further occurrences for degraded grid voltage, the licensee's long term corrective actions, and the requirements the licensee provided to the ECC. In addition, the inspector toured the ECC, reviewed the grid information available at the ECC and discussed the Palo Verde site voltage requirements with ECC personnel. The inspector also reviewed use of site VARs to restore grid voltage, in that during a future event, none of the site main generators may be operating.

The inspector noted that the Palo Verde site did not have accurate on-line capability to monitor grid voltage. Unit 1 has a meter, but it was not accurate enough to detect small changes in grid voltage. The inspector had taken part in discussions between the licensee and regional and Office of Nuclear Reactor Regulation (NRR) staff personnel subsequent to the February 15, 1995, TS 3.0.3 entry. NRR personnel reported they were reviewing a licensee request to change the TS degraded grid voltage relay setpoint and range.

The inspector reviewed Procedure 41AO-1ZZ57, "Degraded Grid Voltage," Revision 4. This procedure provided operator guidance for all three units for response to degraded grid voltage in various plant modes. The basic action was to restore one emergency bus in each unit by blocking the fast bus transfer of nonsafety-related loads to the startup transformers which supplied the safety-related loads. The inspector reviewed the affect of blocking the fast bus transfer and determined that licensee calculations indicated this block would allow safety-related voltage to remain above the degraded voltage relay setpoint.

The inspector determined that grid voltage, current, and VAR information were readily available in the ECC. The inspector discussed the February 15, 1995, event with ECC personnel. ECC personnel indicated that operators were aware that their actions could lower grid voltage and they were prepared to raise the voltage as necessary. Based on discussions with the licensee, ECC personnel stated that in the future they would raise grid voltage first before taking actions similar to those of February 15. The inspector reviewed licensee letter File 95-005-419.8, "PVNGS Expectations Regarding Evaluations Potentially Affecting Grid Voltage Range Limits," dated February 23, 1995, and ECC internal instructions, and noted that operational expectations were clearly stated. In addition, the inspector noted that the ECC had in place an audible alarm for when grid voltage at the site approached 100 percent.

The inspector noted that the licensee had used the site main generators to raise grid voltage during the February 15, event and questioned the licensee as to whether ECC personnel could have raised this voltage external to the site on February 15, or during future occurrences when there was no site generation. The licensee provided the inspector a grid study titled, "PVNGS 525kV Voltage Regulation Study Report." This report concluded that the grid could reliably be maintained above 98 percent, without site generation support.

Based on the discussion above, the inspector concluded that the licensee had taken reasonable corrective actions to identify when a low voltage condition existed on the grid, and what actions to take to ensure that Palo Verde units remained operable and complied with TS shutdown criteria. The inspector also noted that most of the calculations associated with these LERs were based upon a new TS setpoint and range of operation of the degraded grid relays which were currently under review by the NRC staff.

These LERs will remain open, pending NRC staff approval of the degraded grid relay TS change, inspector review of associated calculations, and review of completed or committed long term corrective actions.

11 IN-OFFICE REVIEW OF LERs (90712)

The following LERs were reviewed in-office and determined to be acceptable:

- LER 528/95-05: EDG inoperable due to debris in cooling water heat exchanger. This issue was reviewed in detail in NRC Inspection Report 50-528/95-06; 50-529/95-06; 50-530/95-06.

- LER 528/95-08: Reactor Trip on low SG level due to the inadvertent closing of a feedwater isolation valve (Section 2.1).

ATTACHMENT 1

1 Persons Contacted

1.1 Arizona Public Service Company

*T. Cannon, Acting for Director, System Engineering
*B. Grabo, Section Leader, Nuclear Regulatory Affairs
*J. Hesser, Director, Design & Projects Engineering
*W. Ide, Director, Operations
*A. Krainik, Department Leader, Nuclear Regulatory Affairs
J. Levine, Vice-President, Nuclear Production
R. Lucero, Department Leader, Electrical Maintenance
*D. Mauldin, Director, Maintenance
J. Minnicks, Department Leader, Maintenance Valve Services
*W. Montefour, Senior Representative, Strategic Communications
M. Muhs, Section Leader, System Engineering
*G. Overbeck, Vice-President, Nuclear Support
M. Radspinner, Section Leader, Design Engineering
F. Riedel, Department Leader, Operations Unit 2
M. Salazar, Section Leader, Maintenance Valve Services
*C. Seaman, Director, Nuclear Assurance
D. Smith, Department Leader, Operations Unit 1
W. Stewart, Executive Vice-President, Nuclear
*R. Stroud, Regulatory Consultant, Nuclear Regulatory Affairs
J. Taylor, Department Leader, Operations Unit 3
P. Wiley, Department Leader, Operations

1.2 NRC Personnel

*K. Johnston, Senior Resident Inspector
*D. Garcia, Resident Inspector
*A. MacDougall, Resident Inspector

1.3 Others

*J. Draper, Site Representative, Southern California Edison
*F. Gowers, Site Representative, El Paso Electric
*R. Henry, Site Representative, Salt River Project

*Denotes those present at the exit interview meeting held on June 29, 1995.

The inspector also held discussions with and observed the actions of other members of the licensee's staff during the course of the inspection.

2 EXIT MEETING

An exit meeting was conducted on June 29, 1995. 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

LIST OF ACRONYMS

ADV	atmospheric dump valve
AFAS	auxiliary feedwater actuation signal
AFW	auxiliary feedwater
AO	auxiliary operator
APS	Arizona Public Service
CE	Combustion Engineering, Inc.
CRDR	condition report/disposition request
CRS	control room supervisor
CT	condensate transfer
ECC	energy control center
EDG	emergency diesel generators
EOP	emergency operating procedure
EQ	equipment qualification
ESD	excess steam demand
ECW	essential cooling water
gpm	gallons per minute
HELB	high energy line break
HPSI	high pressure safety injection
HR	hydrogen recombiner
I&C	instrumentation and controls
IN	NRC Information Notice
Kv	kilovolt
LER	licensee event report
LOCV	loss of condenser vacuum
MOV	motor operated valve
MSSV	main steam safety valve
MSSS	main steam support structure
NPRDS	Nuclear Plant Reliability Data System
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PDR	public document room
PM	preventive maintenance
PVNGS	Palo Verde Nuclear Generating Station
RAMS	refueling and maintenance services
RCA	radiological controlled area
RCS	reactor coolant system
SG	steam generator
SOV	solenoid operated valve
SS	shift supervisor
SSM	site shift manager
ST	surveillance test
TS	Technical Specification
VAR	reactive voltampere
VTM	vendor technical manual
WO	work order