APPENDIX A

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/94-37
50-529/94-37
50-530/94-37

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, Arizona

Inspection Conducted: December 1, 1994, through January 14, 1995

Inspectors: K. Johnston Senior Resident Inspector
H. Freeman Resident Inspector
J. Kramer Resident Inspector
A. MacDougall Resident Inspector
D. Garcia Resident Inspector - South Texas Project

Approved: H. Wong, Chief, Reactor Projects Branch F 2/22/95 Date

Inspection Summary

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

Results (Units 1, 2, and 3):

Operations

Inspectors continued to note improvements in the conduct of operations in all three units. For example, an attentive auxiliary operator identified a small crack on an emergency diesel generator (EDG) intake manifold and the licensee appropriately performed an operability evaluation of the manifold leak and concluded that the diesel was operable (Section 2.4). Operations personnel also responded promptly to a leaking pressurizer spray valve (Section 2.6). However, a minor weakness was noted in that Unit 3 operators failed to

independently verify the position of the essential chiller disconnects as required by procedure (Section 2.3).

Maintenance

Overall, inspectors noted improvements in maintenance activities which appear to reflect management attention to work in the field and to plant material condition. For example:

- A test of the essential ventilation system, to develop filter replacement criteria in support of the licensee's implementation of the revised maintenance rule, identified a low flow condition that would not have been identified otherwise (Section 2.2).
- The good maintenance practices and supervision were observed during the troubleshooting, repair, and testing of an atmospheric dump valve (Section 3.3 and 4).
- The licensee has noticeably improved the material condition of the EDGs, but longstanding deficiencies in the nonsafety-related diesel trip system contributed to extended unavailability (Section 3.2).

Continued minor weaknesses in the area of work instruction quality and procedural adherence were noted by the inspectors. In one instance, an unnecessary instruction to check for hydrogen gas when breaching the charging system was ignored by the maintenance personnel. This demonstrated the lack of a thorough work package review by both the maintenance team leader and maintenance worker (Section 3.1).

Engineering

Engineering followup of some issues was very thorough, although some NRC prompting was required to assure timely resolution. Examples of thorough engineering followup included the review of a misassembled snubber in Unit 3 to assure this was an isolated deficiency (Section 6) and the review of NRC Information Notice (IN) 94-60 regarding power limits with inoperable main steam safety valves which identified a weakness in their accident analyses as well as a potentially generic issue (Section 5.1). However, the timeliness of the accident analyses review was left as an unresolved item, pending further review.

Engineering troubleshooting on the Unit 3 turbine-driven auxiliary feedwater pump (TDAFWP) was not well controlled. The success of the troubleshooting effort was largely attributed to the direct involvement of senior engineering management. While this demonstrated an appropriate level of work oversight, it highlighted a weakness in engineering troubleshooting processes (Section 5.2).

Summary of Inspection Findings:

- One inspection followup item was noted in Section 3.2.
- One unresolved item was identified concerning the licensee's evaluation of NRC Information Notice 94-60 addressing power operation with main steam safety valves gagged (Section 5.1).
- Violation 530/9416-04, concerning the bent EDG connecting rod, and Violation 529/9420-05, concerning the failure to follow procedures for a 10 CFR 50.59 evaluation, were closed (Section 7).
- LER 528/94-07, Revision 0, was closed (Section 8). LERs 528/94-08, Revision 0, 529/94-03, Revision 0, and 529/94-04, Revision 0, were closed (Section 9).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - List of Acronyms

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period in Mode 1 at approximately 18 percent power. The unit had completed repairs to a leaking pressurizer vent valve at the end of the previous inspection period and was conducting power ascension to full power. On December 2, 1994, the unit reached 98 percent.

On December 14, there was a major grid disturbance in central California. At approximately 1:30 a.m., the grid frequency lowered to around 59 hertz and resulted in load swings of a maximum of 100 megawatts for about 7 minutes. During the event, control systems responded as designed, no equipment damage occurred, and no other operator actions were required.

On December 19, the licensee implemented a Technical Specification (TS) change, which raised the maximum allowed power from 98.2 percent to 100 percent with one main steam safety relief valve inoperable in each generator, and then raised power to 100 percent. The unit remained at essentially 100 percent power until commencing a downpower on January 14 for steam generator (SG) chemistry hideout return. The unit ended the inspection period at 70 percent. Power was increased to 100 percent the following day.

1.2 Unit 2

Unit 2 operated throughout the inspection period at essentially 100 percent power. On December 10, a partial loss of control room annunciators occurred when a power supply to the annunciator system failed. The annunciators were restored within 15 minutes (Section 2.1). The California grid disturbance affected Unit 2 as in Unit 1.

1.3 Unit 3

Unit 3 began the inspection period in Mode 5 for a SG tube inspection. On December 17, the unit entered Mode 2, and began power ascension to 100 percent power. The unit remained at essentially 100 percent power through the remainder of this inspection period.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Partial Loss of Control Room Annunciators - Unit 2

On December 10, 1994, at about 9:46 a.m., technicians were performing corrective maintenance in one of the power supply cabinets for the control room annunciator system in Unit 2. While removing a circuit card, one of the technicians dropped a flat washer into a power supply inverter. This caused the failure of the inverter and blew the fuse for the inverter backup power supply.

When the fault occurred, control room operators received an annunciator power supply trouble alarm and several alarm conditions: emergency safeguards features (ESF) equipment and chemical and volume control system equipment alarm windows; SG and feedwater systems alarm windows were in fast flash; and turbine generator, auxiliary systems, and the turbine trip first out had all alarm windows out. These alarms would not respond to any control board push buttons and were considered inoperable.

About one-half of the control room alarm panels were available to the operators; and the plant monitoring system, safety equipment status system, emergency response data acquisition system, and quality safety parameter display system were operable. The operators implemented the "Loss of Annunciators" abnormal procedure and reviewed the plant TS, event reporting manual, and emergency plan and determined that no event classification was required. At about 10:08 a.m., technicians replaced the blown fuse and restored the control room annunciator system.

The inspector reviewed applicable procedures and determined that the operators appropriately followed plant procedures and that safety-related equipment remained operable. The inspector also met with the maintenance engineer and determined that the system responded as expected when the inverter and backup power supply fuse failed. The maintenance engineer initiated a condition report/disposition request (CRDR) which included a corrective action to install a guard around the inverters to minimize the potential for similar events. The inspector concluded that these actions were appropriate.

2.2 <u>ESF Switchgear Room Essential Ventilation Air Handling Unit Testing - Unit 1</u>

On January 6, 1994, during testing, the licensee found that the ESF switchgear room essential Air Handling Unit (AHU), HJA-Z03, was not supplying the design air flow of 4100 standard cubic feet per minute to the 4160 volt safety-related switchgear rooms. The system engineer had developed a special test to determine the differential pressure across the intake filter that would prevent the AHU (HJA-Z03) from supplying the design basis air flow. This information would then be used as the basis for periodically replacing the filters. When the engineers started the test the indicated flow was only 2900 standard cubic feet per minute without any obstruction across the intake filter.

The shift supervisor immediately declared the AHU inoperable. Although the AHU is not specifically included in the plant TSs, it was required to be operable to support operability of the Train A 4160 volt safety-related load center. The licensee's administrative controls required the AHU to be returned to an operable status within 72 hours or the affected 4160 volt load center be declared inoperable. The inspector reviewed the licensee's procedures and TSs and concluded that the licensee appropriately controlled operability of the AHU.

The licensee conducted a detailed walkdown of the ventilation lineup and found the return supply damper for the AHU only 10 percent open (normal position is 100 percent open). Technicians found that a nut had come loose and allowed the damper to close to the 10 percent open position. The damper was repositioned, the air flow retested, and the AHU was declared operable. The site shift manager verified that the supply damper for the Unit 1 Train B ESF switchgear room essential AHU and both trains of the Unit 2 and 3 ESF switchgear room essential AHUs were in the 100 percent open position.

The licensee initiated a root cause of failure CRDR. The inspector concluded that the licensee appropriately restored operability of the ESF switchgear room essential AHUs and corrected the immediate safety concern. The inspector will review the licensee's investigation of this event during a future inspection.

2.3 Independent Verification - Unit 3

During a review of the essential chill water system on January 13, 1995, the inspector noted that the licensee failed to perform the independent verification of the essential chiller disconnects as required by procedure. The inspector notified the shift supervisor of the problem. The shift supervisor dispatched an operator to verify that the disconnects were closed. Subsequent review identified that an open disconnect situation would have been alarmed in the control room. There were no such alarms at the time.

The licensee performed sections of Procedure 43OP-3EC01/2, "Essential Chilled Water Train A/B," for the chemistry department to draw a weekly sample of the circulating water system. The procedure, in part, required the operators to open the disconnects, start the circulating water pump, close the disconnects, and independently verify the disconnects were closed. The inspector noted in a review of procedure records that on two occasions, Unit 3 operators had failed to perform the independent verification.

The licensee performed several corrective actions. The shift supervisor directed an operator to check the disconnect positions. They were in the appropriate positions. The licensee issued a night order to the operations personnel emphasizing the requirement to perform independent verifications. In addition, the licensee initiated a CRDR to evaluate the problem.

The inspector concluded that the licensee performed adequate corrective actions. The inspector noted that the operators would receive several control room alarms if the disconnects were left open. The lack of alarms provided the operators an indication that the disconnects were closed although an independent verification was not performed. Therefore, the inspector concluded that the failure to follow procedure was of minor significance.

The inspector noted that a recent trend analysis performed by Nuclear Assurance identified that instances of equipment and valve misalignments were substantially greater in Unit 3 than the other two units. In response to these findings, Unit 3 operations management was taking action to improve

performance. The example noted in this section would tend to support the performance trend identified by Nuclear Assurance.

2.4 EDG Intake Manifold Leak - Unit 1

While performing a routine surveillance test (ST) on EDG 1A on December 27, 1994, an auxiliary operator noted what appeared to be a cracked weld on the number four right cylinder intake manifold. The hairline crack was approximately 3/4 inches long that ran across the weld at the flange. The crack was apparently "through-wall" which caused a barely detectable air leak while the EDG was operating. The licensee conducted an operability evaluation and concluded that the crack did not affect the operability of the EDG.

On December 28, the inspector observed the cracked weld. The inspector noted that the crack was across the weld. This weld joined the cylinder head bolting flange to a square section of pipe (approximately 6 x 6 inches) which provided forced air from the intake plenum. The inspector noted that the weld appeared to be old, due to some oxidation indications in and around the weld. The inspector concluded that the crack did not appear to be propagating and did not appear to affect the structural integrity of the manifold.

The inspector reviewed the licensee's operability determination. The inspector noted that the licensee's inspection of the crack included a certified level III visual weld inspector. The level III inspector, and engineering and maintenance personnel concluded that the crack was insignificant. The licensee also concluded that if the weld failed circumferentially 360 degrees around the pipe (unlikely due to crack orientation), the other nine intake flange welds were sufficient to support the intake plenum and that the EDG would remain operable.

The inspector concluded that the licensee took the appropriate steps to ensure that the deficiency did not affect the operability of the EDG. The inspector agreed with the licensee's conclusion that the crack was insignificant and did not affect the operability of the EDG. Finally, the inspector concluded that the auxiliary operator had done an excellent job in identifying and notifying management of the presence of the crack.

2.5 EDG Material Condition - Units 1, 2 and 3

Throughout the inspection period, the inspectors noted improving material conditions of the EDGs in all three units. The inspectors noted that, in some cases, all of the standing oil and the oil absorbent devices had been removed. In previous inspections, inspectors had noted numerous oil leaks and 30 or more different oil absorbent devices saturated with oil on one diesel alone.

At the exit meeting, the Director of Maintenance mentioned that they had targeted the deficiencies of the diesels and that they would continue to improve the material conditions. The inspectors concluded that the licensee

was making good progress in correcting minor deficiencies, such as oil and cooling water leaks, in an effort to improve the material conditions of the EDGs.

2.6 Pressurizer Spray Valve Leakage - Unit 2

On December 21, 1994, operations determined that one of two pressurizer spray valves in Unit 2 had developed a 6 gallon per minute packing leak. Operators entered the containment and isolated the spray valve which stopped the leak. Repairs were planned for the Unit 2 refueling outage scheduled to begin February 4, 1995. Operations demonstrated prompt response to the leakage indication.

3 MAINTENANCE OBSERVATIONS (62703)

3.1 Charging Pump Packing Replacement - Unit 2

On January 5, 1995, the inspector observed mechanical maintenance technicians install new packing on the plungers of charging Pump A in Unit 2. The work was being performed using model work Procedure 31MT-9CH01, "Charging Pump Disassembly and Assembly." The inspector observed good radiological protection work practices by the mechanics and good oversight of the activity by an RP technician. The inspector noted that the model work instructions were detailed and technically accurate.

The inspector noted that the procedure had a step to perform a hydrogen gas check when the system was breached if directed by the team leader. The inspector determined that the lead mechanic had not received instructions from the team leader concerning the hydrogen check and subsequently did not perform the check when the system was breached. In discussions, the team leader stated that he reviewed the work order, but did not notice the step to perform the hydrogen gas check.

The inspector noted that the licensee did not historically have any problems with excessive hydrogen gas in the charging system and that the failure to perform the step had low safety significance. However, the inspector was concerned that the team leader and the lead mechanic did not thoroughly review the work procedure.

The inspector discussed the problem with the mechanical maintenance department leader who agreed that the prejob briefing did not meet management's expectations. The licensee's corrective actions included reinforcing the need to conduct thorough prejob briefings especially when the team members had not recently worked on a particular system. The licensee also decided that the step to perform the leak check was not necessary and removed the step from the procedure. The inspector concluded that the licensee's response was appropriate.

3.2 Multiple EDG Trips - Unit 2

On December 14, 1994, the Unit 2 EDG B was started in the emergency mode and satisfactorily loaded for a monthly ST. After the EDG was unloaded for the engine cooldown, the surveillance procedure required that the emergency mode interlock defeat switch be placed in the off position which enabled the test mode trip circuitry. When the operator moved the switch to the off position, the incomplete sequence alarm momentarily came in and the EDG tripped. Operators declared the EDG inoperable and the maintenance engineers developed a troubleshooting plan.

The inspector observed electrical maintenance engineering troubleshoot the test mode circuitry. The engineers suspected that some relays must have opened long enough to cause the trip solenoid to deenergize. The technicians removed the most probable relays and found two normally energized relays with open contacts that would not pick up.

On December 15, after replacing the faulty relays, operators started the EDG in the test mode to perform a maintenance run. During the test run, the EDG tripped during the cooldown cycle on an indicated high jacket water temperature alarm. The technicians suspected the problem was in the nonsafety-related pneumatic trip circuitry. The technicians found air leaks in the check valve associated with the high jacket water temperature alarm and the temperature trip valve. These components were replaced and the EDG was again started in the test mode and immediately tripped on incomplete sequence since it did not reach rated speed. The technicians found some minor air leaks and a leaking check valve that was replaced.

On December 16, the EDG was successfully started in the test mode. During the cooldown cycle, the EDG tripped on an indicated low turbocharger lube oil pressure alarm. The technicians found a piece of debris in the check valve associated with the low turbocharger lube oil pressure alarm. The debris damaged the seat of the check valve and caused it to leak. The technicians replaced the check valve and successfully started the EDG in the test mode. The EDG would not stop after completion of the cooldown cycle and would not shutdown when the emergency pushbutton was depressed. The EDG was stopped by manually tripping the fuel racks.

The licensee suspected the problem with the EDG not stopping was caused by sluggish operation of the pneumatic control valves. Two control valves were replaced and the EDG was successfully started and shutdown in the test mode. During the evening of December 16, the ST was satisfactorily completed and the EDG was restored to an operable status.

The inspector reviewed the troubleshooting work orders, the EDG logs, the control room logs, and discussed with the system engineer the root cause of failure analysis. Based on this review, the inspector had the following observations:

- All five of the problems would not have prevented the EDG from starting and running in the emergency mode. However, the EDG was unavailable (would not start on an emergency signal) for a total of 20 hours during the troubleshooting activities. The inspector was concerned that having the EDG unavailable for this period of time increased the vulnerability of the plant.

- Engineering had previously developed an action plan to reduce the number of EDG test mode trips. The corrective actions included replacing continuously energized Agastat relays every 10 years and replacing the check valves with an improved check valve that had better seating characteristics and an internal filter. These improvements were scheduled for installation during the Unit 2 refueling outage in February 1995.

- The licensee's performance during the troubleshooting efforts may have been inconsistent. The inspector observed good troubleshooting and work practices during the first problem with the relays. However, one of the leaking checks valves may have been caused by debris introduced into the air system during replacement of an earlier check valve. Additionally, the cause of one event was not fully corrected and may have subsequently caused the problem with not being able to stop the EDG.

- The performance of the 8-hour surveillance requirement to check the offsite power sources with an inoperable EDG were not consistently documented in the unit log. However, the procedure used to perform the ST was correctly completed every 8 hours as required by the plant TS. The licensee issued a night order emphasizing management's expectation that compliance with TS action statements be documented in the unit log. The inspector concluded that these actions were appropriate.

At the same time the inspector was raising questions regarding the cool-down cycle trips, the licensee was also reviewing these events. The licensee initiated a root cause of failure CRDR for the multiple failures. The Director of Engineering also raised the priority of the effort to reduce the number of test mode EDG trips to level 1 action plan (highest priority) to include the experience of the EDGs in all three units. The inspector will review the licensee's formal root cause evaluation and corrective actions during a future inspection (Followup Item 529/9437-01).

3.3 Atmospheric Dump Valve (ADV) Maintenance - Unit 3

During routine ST of the ADV-185 in Unit 3, technicians noticed that the valve was making a "popping" noise in the closed direction. The licensee suspected that the noise was coming from the valve actuator and rebuilt the valve operator. During the retest, the valve continued to make the popping noise and its stroke time placed it in the enhanced monitoring range. The licensee then suspected a problem internal to the valve and disassembled the valve on December 15. On December 19, the valve was reassembled and successfully retested.

The inspector reviewed the vendor technical manual (VTM) and model work Procedure 31MT-9SG04, "ADV Disassembly and Assembly." The inspector noted that all the critical acceptance criteria in the VTM were included in the procedure. The inspector noted that the model procedure used a different type and arrangement of packing rings than described in the VTM. The system engineer stated that engineering had done an evaluation to include the ADVs in the licensee's valve packing program. The inspector noted that the work order had a step to repack the valve per the valve packing installation procedure and referenced the engineering evaluation. The inspector concluded that engineering had a good basis for using a different packing arrangement and that the model work instructions were thorough and technically accurate.

The inspector observed mechanical maintenance personnel disassemble the valve on December 15. The inspector noted good supervision in the field and good work practices by the mechanics. The maintenance engineer conducted a detailed review of the parts and thought that the valve piston may have been periodically hanging up on the piston rings. The piston rings were slightly worn at the split which caused increased friction at the location of the ring split. The engineer suspected that the piston ring wear resulted when the valve was stroked several times during the testing in November 1994. Testing is typically performed with an upstream isolation valve closed, isolating steam which acts to lubricate the rings.

The mechanical maintenance engineer initiated a CRDR to document the root cause of failure. As a corrective action, the engineers were considering putting a caution in the procedure for adjusting the valve positioner that would require water to be injected into the valve bonnet in cases of multiple strokes without steam. The inspector concluded that the licensee's initial corrective actions were appropriate.

3.4 Other Maintenance Observed

- Maintenance of medium voltage circuit breakers Type AM-4.16-250 - Unit 1
- Electrical design change on the 4.16 kV bus breakers - Unit 1
- New fuel receipt - Unit 2
- Installation of new AC input supply circuit breaker for the "D" battery charger - Unit 2

4 SURVEILLANCE OBSERVATIONS (61726)

ADV Testing - Unit 3

On December 19, 1994, the inspector observed a 100 percent stroke test of an ADV from the control room. The licensee performed ST 43ST-3SG04, "Testing ADV's in Mode 1," Section 8.7. The inspector observed good command and control of the evolution by the control room staff. The inspector noted good

communications between the control room operators and the operators at the ADV. The inspector noted the coordination between the control room operators minimized plant perturbations during the stroke test. The test was conducted successfully. The inspector concluded operations exhibited a strong performance throughout the test.

5 ONSITE ENGINEERING (37551)

5.1 NRC IN 94-60: Power Operation with Main Steam Safety Valves (MSSV) Gagged

The inspector conducted a review to determine if the licensee had evaluated NRC IN 94-60, "Potential Overpressurization of Main Steam System," issued on August 22, 1994. IN 94-60 discussed a potential for overpressurizing the main steam system during previously evaluated accident scenarios when one or more MSSV was inoperable. The inspector selected this IN to review because Unit 1 was operating at 98 percent power in compliance with TS due to having two inoperable MSSVs.

The IN discussed that most plant TS allow power operation with inoperable MSSVs at a power level that was equivalent to the capacity of the remaining MSSVs. The basis of this TS assumes that the maximum allowable initial power level is a linear function of MSSV capacity. However, Westinghouse determined that the linear assumption for reducing power levels with inoperable MSSVs was nonconservative and may result in overpressurizing the secondary system during accident scenarios with inoperable MSSVs.

The licensee's operational experience review (OER) group screened the IN as applicable in September 1994 since the basis for the TS for power operation with inoperable MSSVs also assumed a linear reduction of power with MSSV capacity. The inspector noted that the licensee conducted a preliminary review of the condition addressed in the IN in October 1994. The licensee noted that the original safety evaluations of the loss of condenser vacuum (LOCV) accident concurrent with a total loss of feedwater were performed with all the MSSVs operable and did consider the potential of overpressurizing the secondary system when operating at the reduced power levels with inoperable MSSVs.

The safety analysis engineers used the previously licensed Combustion Engineering (CE) simulation of the LOCV accident and ran the program with up to two inoperable MSSVs in each SG and determined that there was no significant increase in main steam pressures with inoperable MSSVs. The licensee believed the condition in Unit 1 with two inoperable MSSVs was acceptable based on this initial review. The OER group scheduled a detailed review of the IN to be completed by March 31, 1995.

The inspector noted that the licensee had submitted a TS amendment to allow Unit 1 to operate at 100 percent power with the two inoperable MSSVs. The inspector questioned the licensee's decision to not complete a detailed, formal evaluation of the concerns in the IN prior to completing the TS

amendment. Based on the inspector's concerns, the OER group moved up the review date for the IN to December 31, 1994. On December 14, the TS amendment for raising power to 100 percent was issued by the Nuclear Reactor Regulation and Unit 1 returned to 100 percent.

In December 1994, after Unit 1 had increased power to 100 percent, safety analysis engineers determined that although the previous LOCV analysis assumed initial plant conditions and parameters that would generate the most limiting primary pressure, these conditions did not assure maximum secondary pressure. Additionally, the engineers determined that CE had not previously formally evaluated the secondary overpressurization condition discussed in the IN.

As a result, the safety analysis group changed the initial plant conditions and parameters used in the LOCV accident to increase the heat transfer to the SGs and make the secondary side pressure more limiting. The analysis was performed for the condition in Unit 1 with two inoperable MSSVs and was found to be acceptable. However, preliminary runs were performed for additional inoperable MSSVs and the potential for overpressurizing the main steam system may occur at lower power levels with the maximum of four MSSVs in each SG inoperable (as allowed by TS).

The inspector reviewed the IN and had numerous discussion with the safety analysis engineers, licensing engineers, and the OER group. Based on these discussions the inspector concluded that the licensee had conducted an appropriate initial review of the concerns addressed in the IN. Additionally, the inspector agreed with the licensee that operation in Unit 1 at 100 percent power with two inoperable MSSVs was not a safety concern. However, the inspector was concerned that the licensee had not identified the incorrect assumptions with the LOCV accident during the development of the TS submittal for returning to 100 percent power with two inoperable MSSVs.

The licensee initiated a CRDR to perform the detailed analysis of the condition and determine if any changes to the TS for inoperable MSSVs was required. The inspector will review the CRDR during a future inspection to determine if the licensee should have discovered the incorrect assumptions in the LOCV accident simulation during the development of the TS amendment submittal and confirm whether a generic safety concern exists for secondary overpressurization events (Unresolved Item 528/9437-02).

5.2 TDAFWP Failure - Unit 3

On December 20, 1994, the inspector observed licensee personnel perform portions of the work activity associated with the investigation of an overspeed trip of the Unit 3 TDAFWP. On December 19, operators noted low TDAFWP steam supply line temperatures and started the pump to raise the temperature in the line. This action was taken in response to the licensee's analysis of previous TDAFWP trips caused by condensation which had formed in cold steam supply lines. In accordance with operating procedures, operators started the TDAFWP by opening valves in one steam supply. The pump started as

designed, and operators opened valves in the second steam supply line. The TDAFWP began to overspeed, and subsequently tripped.

Operators declared the TDAFWP inoperable, the unit entered a 72-hour TS action statement, and a CRDR was initiated. An investigation team assembled to determine the root cause of the TDAFWP trip. The team was led by system engineering personnel. On December 20, the inspector observed the team members as they participated in collecting and verifying data and facts. The inspector observed good communication techniques between the different organizations.

The investigation team developed an action plan to recreate the scenario of December 19. The steam piping low points were purged of condensation, and initial testing revealed that previous condensation buildup in the horizontal section just upstream of a check Valve (SG-V43) upstream of the steam supply line header was the cause for the turbine to trip on overspeed. However, the performance of the governor valve remained in question and the team determined that further testing in the presence of a representative from the governor valve vendor was warranted.

On December 21, another action plan was developed to start the TDAFWP in the same valve configuration with established atmospheric conditions. Test instrumentation and strip chart recorders were installed to record the turbine responses.

An initial run of the TDAFWP was aborted due to an instrument fitting leak. The horizontal section upstream of the check Valve (SG-V43) had higher steam line temperatures and, therefore, the decision was to remove some of the insulation to allow the piping to cool down.

The inspector noted that the Director of System Engineering and a system engineering team leader were present during this testing and was involved in ensuring that questions regarding personnel overtime limits, approved work orders for removing the insulation, and action plans for testing the TDAFWP were properly addressed.

The system engineering team leader discussed his hand written instructions for resuming the test with the relief test coordinator who had been involved with the earlier testing. A prejob briefing was held in the control room with all the personnel involved in the testing of the TDAFWP. The prejob briefing was presented by the Director of System Engineering using the handwritten instructions to discuss the evolutions that were going to take place.

While the inspector found that the involvement of the director of site engineering indicated appropriate management attention to this testing, the inspector observed that considerable direct involvement appeared necessary to ensure that the troubleshooting effort was conducted properly. The inspector noted that the action plan lacked prerequisites, precautions, limitations, and contingency plans to insure that issues such as temperature changes, communications between organizations, and shift turnover were adequately

addressed. In addition, the licensee did not have instructions to provide documentation of test parameters or results.

The inspector discussed these findings with the Director of System Engineering who concurred that the testing was not conducted consistent with his expectations. The Director concluded that a special test procedure was not appropriate for this test. While the inspector agreed that this testing did not require the rigor of a special test procedure, the testing involved several disciplines, extended through shifts, and involved configuration control issues which warrant sufficient formality to assure effective communication of the testing process. A CRDR was initiated by site engineering to review guidance for engineering troubleshooting. The inspector will review the guidance in a future inspection.

6 FOLLOWUP - MAINTENANCE (92902)

Misassembled Mechanical Snubber - Unit 3

In July 1994, an NRC inspector questioned the performance of a mechanical snubber installed on a Unit 3 auxiliary feedwater pump steam trap line after he found the snubber would not rotate on its pins. Although an engineer initially confirmed that the snubber would not rotate, during a subsequent inspection, the snubber was found to rotate as expected.

On December 14, 1994, with Unit 3 transitioning from Mode 5 to Mode 4, a licensee engineer performed a followup inspection and noted that the cold position of the snubber was the same as the hot position he had previously observed. The licensee subsequently discovered that the snubber had been inappropriately reworked and misassembled. The snubber, which was supposed to be a 1/4 thousand-inch-pound (kip) snubber, had been assembled with both 1/4 kip and 1/2 kip snubber parts. The net result was that the snubber had a shorter stroke than design. The licensee replaced the snubber.

The licensee determined, based on documentation of testing during the 1992 Unit 3 refueling outage, that this snubber had been intact when it was removed from the system and had been tested satisfactorily. However, a comparison of the as-found and as-left pin-to-pin dimensions indicated that the reinstalled snubber did not match the snubber which had been removed. This indicated that the snubber had been modified after testing and prior to reinstallation. There was no documentation of a modification to the snubber and the licensee stated that it was not their practice to rework small snubbers.

The inspector determined that the snubber deficiency could not have been readily identified with the plant in Mode 1 and that the licensee's initial review in response to the July 1994 inspection finding has been reasonable.

The inspector questioned whether the licensee had assurance that this was an isolated case. The licensee performed walkdowns of a large sample of 1/4 kip snubbers and performed a complete review of test documentation. They

concluded that this had been an isolated case. The inspector reviewed the licensee's efforts and found them to be appropriate.

The licensee subsequently interviewed maintenance personnel involved in the removal and testing of the snubber in the 1992 refueling outage. However, personnel involved in the outage could not recall a modification having been performed and reiterated the practice of discarding 1/4 and 1/2 kip snubbers with deficiencies. The licensee was not able to contact some contract maintenance workers which are no longer working for the licensee. The inspector determined that the licensee had performed a reasonable investigation of this matter.

The inspector questioned whether an evaluation should be performed to determine the impact of the as-found condition of this snubber on system performance during a design basis event. The snubber, which was in its fully extended position when installed with the steam line cold, would not have allowed pipe movement as the system heated up. The licensee evaluated the configuration and found that the loading on the line would not have exceeded the design basis. The inspector noted that the line was relatively long and small in diameter, providing considerable flexibility, which supports the licensee's analysis.

Although the licensee could not identify how the snubber was misassembled, corrective action was taken to inform craft involved in snubber testing of the misassembled snubber and to reiterate the expectation that snubbers of this size are not to be reworked. The inspector found this action to be appropriate.

7 FOLLOWUP - ENGINEERING (92903)

7.1 (Closed) Violation 530/9416-04: Bent EDG Connecting Rod - Unit 3

This violation was issued for failure to promptly identify and correct a bent connecting rod in Cylinder 6-L of Unit 3 EDG B which occurred during a rocker arm failure on July 28, 1993. The licensee noted symptoms of the bent connecting rod on October 20, 1993, but failed to identify the problem until March 23, 1994.

The inspector reviewed the licensee's investigation and corrective actions regarding the violation. The licensee concluded that the violation was caused by failing to promptly validate assumptions used in analyzing the indications obtained on October 20, 1993, and compounded by poor communications between and within organizations. Additionally, the licensee concluded:

- Some of management's expectations were not clearly communicated (i.e., to challenge assumptions and follow issues to closure),

- Communications problems existed within and between organizational departments leading to poor interaction or coordination of evaluation findings,
- Issues were not followed to closure in a timely manner, and
- A self-critical attitude did not exist at all levels which led to a less aggressive approach to the problem.

The inspector noted that the licensee's findings of the root cause of the violation were very similar to the NRC findings related to this event documented in NRC Special Inspection 50-530/94-16.

The inspector reviewed the licensee's corrective actions of which the most significant action involved the licensee's reengineered organization which was implemented in August 1994. Two of the contributing factors to the violation were poor communications and a lack of management involvement. The reengineered organization now consists of teams for each system that include engineering, maintenance, and planning personnel. The closer working relationship was intended to foster freer communications, especially between the maintenance engineers and the maintenance craft. NRC Inspection Report 50-530/94-16 noted that the maintenance craft and planner suggested to remove the crank case inspection cover in December 1993, but did not pursue the suggestion.

Additionally, the licensee has implemented a daily meeting between department leaders and other senior managers to discuss plant status, emerging issues, daily maintenance plans, and other issues. Engineering issues/concerns are specifically addressed once per week at these meetings. Also, important issues that are identified by the licensee's condition reporting system are discussed at the daily meeting. By effectively using this meeting, important issues can be identified, prioritized and tracked by senior management. The inspector noted improved communications and more management involvement since implementation of the reengineered organization.

Another change that was not specifically implemented in response to the violation was the operability determination Procedure (40DP-90P26). The inspector reviewed the procedure and noted that it stated that, "whenever the ability of a structure, system or component (SSC) to perform its specified function is called into question by an indication of a potential deficiency . . . then the operability of the SSC shall be determined . . . Otherwise, the SSC should be declared inoperable." In this case, the licensee concluded that the EDG was operable; however, the system engineer was concerned about the long term reliability caused by a potential deficiency. The operability procedure would require deliberate and timely actions to resolve the engineer's concern.

Finally, NRC Inspection Report 50-530/94-16 noted that the retest, following the rocker arm rework in July 1993, consisted only of a simple surveillance

run and failed to identify the degraded condition caused by the bent connecting rod. The licensee decided that to ensure that pertinent data are available for EDG operability determinations following extensive rework, that a leak-down check and an engine analysis would be required. The inspector reviewed the licensee's postmaintenance retest development procedure and verified that the procedure required the inclusion of the specified tests.

The inspector concluded that the actions taken by the licensee were appropriate.

7.2 (Closed) Violation 50-529/9420-05: Failure to Follow Procedures for a 10 CFR 50.59 Evaluation

This violation involved the failure to follow procedures when a 10 CFR 50.59 screening identified that TSs were affected by a design change. In this instance, the design change was implemented before a TS change was submitted and approved by the NRC. The design change rerouted the location of the condenser vacuum exhaust and the affected TS depicted the location of the condenser vacuum exhaust.

As corrective action, licensee management clarified expectations regarding changes to Tss and the need for timeliness in processing change requests. Also, on November 2, 1994, the licensee submitted a TS amendment request which depicted the new location for the condenser vacuum exhaust.

The inspector concluded that the actions taken by the licensee were appropriate.

7.3 Engineering Response to Overspeed of Turbine-Driven Pumps Caused by Governor Valve Stem Binding

NRC IN 94-66 documented recent problems regarding binding of governor valves for turbine-driven pumps that have resulted in overspeed trips. On December 21, 1994, the inspector reviewed internal licensee memorandum addressing this issue for all three units. The inspector interviewed the system engineer and determined that the licensee has taken appropriate action to address the concern.

The inspector was concerned with the recent overspeed trip of the Unit 3 TDAFWP that occurred on December 19 (Section 5.2). The investigation determined that the overspeed trip did not occur as a result of governor valve stem binding. As part of the investigation, the linkage to the governor valve had been disconnected from the servo motor and determined to have full freedom of motion. In addition, the vendor representative inspected the components and found no discrepancies. The governor valve stem had just been replaced in the Unit 3 TDAFWP during the previous outage.

The inspector noted that the licensee's investigation to determine whether stem binding was occurring was thorough and exhaustive.

8 ONSITE REVIEW OF LER (92700)

(Closed) LER 528/94-07, Revision 0: Missed Surveillance Requirement for Containment Purge Isolation Valves

This LER was submitted when the licensee identified that the thermal overload protection circuits had never been verified to be bypassed continuously or under accident conditions per TS Surveillance Requirement 4.8.4.2.1. Two containment purge isolation valves each isolate the intake and the exhaust lines for the containment purge system. The licensee had discovered this omission on November 3, 1994, during a design basis validation review.

The inspector reviewed the actuation signals to these four isolation valves. The inspector noted that the valves receive a containment isolation actuation signal and a containment purge isolation actuation signal (CPIAS). The licensee's design basis review had revealed that the 18-month ST that had been performed for Surveillance Requirement 4.8.4.2.1 had ensured that the thermal overloads were bypassed for a containment isolation actuation signal, but had not ensured this feature for a CPIAS (a different section of the same circuit).

The inspector reviewed the Updated Final Safety Analysis Report for the consequences of the containment purge isolation valves not being operable. The containment purge system was designed to operate only while shutdown, and the CPIAS was intended to terminate the purge which would substantially reduce potential offsite radiological exposures in the event of a fuel handling accident in containment. However, the radiological consequences of a fuel handling accident have been calculated without assuming CPIAS operation, and the offsite doses are still a small fraction of 10 CFR Part 100 limits. Therefore, the inspector concluded that the licensee's failure to test the thermal overload bypass feature for the CPIAS was of low safety significance.

The inspector reviewed the licensee's corrective actions. The inspector noted that the licensee intended to include steps in an operations procedure to ensure that the thermal overload was bypassed during a CPIAS. The licensee concluded that this would meet the once per 18-month requirement. The inspector concluded that the intended corrective actions were appropriate.

9 IN OFFICE REVIEW OF LERS (90712)

The following LER was closed following an in-office review in accordance with inspection module 90712:

- LER 528/94-08, Revision 0, TS Required Shutdown to Repair Leaking Pressurizer Vent Path Valves.

- LER 529/94-03, Revision 0, Missed TS LCO Action for Monitoring Reactor Coolant System Boron Concentration

- LER 529/94-04, Revision 0, Class 1E Batteries in a Degraded Condition

10 MISPOSITIONED LAMP COVERS ON REMOTE SHUTDOWN PANEL

Inspection Report 528/94-34 identified that the inspector found lamp covers mispositioned on the remote shutdown panel in Unit 2. As a corrective action, the licensee initially considered installing security card reading doors at the entry of the remote shutdown panels in all units. Subsequently, the licensee revised their planned preventive actions. They preliminarily propose to install plexiglass covers over the panels with some type of securing tag. The inspector found this planned action to be acceptable.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

J. Bailey, Vice President, Nuclear Engineering & Projects
P. Crawley, Director, Nuclear Fuel
J. Dennis, Section Leader, Operations Support
A. Fakhar, Manager, Site Mechanical Engineering
B. Grabo, Section Leader Compliance, Nuclear Regulatory Affairs
A. Krainik, Manager, Nuclear Regulatory Affairs
D. Mauldin, Director, Site Maintenance and Modifications
J. Scott, Director, Chemistry
M. Sharp, Instructor, Operations Training
W. Stewart, Executive Vice President
R. Stroud, Regulatory Consultant, NRA

1.2 NRC Personnel

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

1.3 Others

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

All personnel listed above attended the Exit meeting held on January 18, 1995.

2 EXIT MEETING

An exit meeting was conducted on January 18, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by the inspectors.

ATTACHMENT 2

ACRONYMS

ADV	atmospheric dump valve
AHU	air handling unit
CFR	Code of Federal Regulation
CPIAS	containment purge isolation actuation signal
CRDR	condition report/disposition request
EDG	emergency diesel generator
ESF	emergency safeguards features
IN	Information Notice
kip	thousand inch pound
LER	licensee event report
LOCV	loss of condenser vacuum
MSSV	main steam safety valve
NRR	Nuclear Reactor Regulation
OER	operating experience review
SG	steam generator
SSC	structure, system or component
ST	surveillance test
TDAFWP	turbine-driven auxiliary feedwater pump
TS	Technical Specification
VTM	vendor technical manual