ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/96-02
50-529/96-02
50-530/96-02

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: January 28 through March 9, 1996

Inspectors: J. Kramer, Resident Inspector
D. Garcia, Resident Inspector
D. Acker, Senior Project Inspector
B. Olson, Project Inspector

Approved: D.F. Kirsch, Chief, Reactor Projects Branch F — 3-29-96 Date

Inspection Summary

Areas Inspected (Units 1, 2, and 3): Routine, announced inspection of onsite review of an event, operational safety verification, maintenance and surveillance observations, onsite engineering, plant support activities, inspection followup items (IFI), and review of licensee event reports (LERs).

Results (Units 1, 2, and 3):

Plant Operations

- Unit 2 operations personnel performed a well coordinated downpower and plant stabilization after identification of the main transformer temperature alarm. (Section 2.1).

- Operators effectively responded to the main turbine trips in Units 1 and 3 (Section 2.2 and 2.3).

- Operators exhibited weak board awareness on two separate occasions. Two startup transformers were cross-tied through a 13.8 kV bus for approximately 18 hours and operators from two crews in two different units failed to recognize the abnormal electrical configuration during their control room board walkdowns (Section 2.2). In addition, an annunciator for the main transformer was in alarm for approximately 40 minutes before operators recognized the alarm (Section 2.1).

- An auxiliary operator (AO) exhibited good attention to detail by identifying that bolts were missing or loose on the emergency diesel generator (EDG) starting air manifold during a walkdown of the diesel (Section 3.2).

- Nonlicensed operators demonstrated a strong knowledge of the gas turbine generators (GTG) (Section 8.1).

- The inspector identified that management expectations, to manually trip the reactor when trip setpoints are approached, were not consistently implemented in that feedwater transients in the past 3 years resulted in nine automatic reactor trips, although none were manually initiated. Operations management is evaluating the guidance given to operators for performing manual actions (Section 10.1).

- A noncited violation was identified regarding the operator's failure to maintain control of new locking seals which resulted in an unknown individual repositioning a main steam bypass valve and locking it in a nonneutral position (Section 10.2).

Maintenance

- Maintenance personnel responded promptly and effectively to several EDG problems (Section 3.2).

- Maintenance activities to troubleshoot and repair a reactor trip switchgear breaker (RTSB) were generally completed in an effective and controlled manner (Section 4.1).

- Maintenance personnel used a reactor coolant pump (RCP) seal mockup and static tester to provide effective seal package replacement training (Section 4.2).

Engineering

- Engineering activities to improve the GTG reliability were generally effective (Section 3.1).

- A noncited violation was identified regarding the failure to exercise adequate design control, during construction, resulting in the failure

to detect calculational errors and omissions regarding backup protection for circuits transitioning containment electrical penetrations (Section 10.3).

Plant Support

- The licensee generally responded well to the situation wherein a rail car of toxic gas was inadvertently brought onto the owner controlled area (Section 7.1).

- There was good radiological housekeeping in Unit 2 high radiation areas (Section 7.2).

Summary of Inspection Findings:

Open Items

- Noncited violation regarding the failure to comply with Technical Specification 3.6.3 in that Main Steam Isolation Bypass Valve SGE-UV-169 was not capable of automatic closure for some indeterminate period greater than 4 hours between December 3 and 20, 1995 (Section 10.2).

- Noncited violation regarding the failure to exercise adequate design control, during construction, resulting in the failure to detect calculational errors and omissions regarding backup protection for circuits transitioning containment penetrations (Section 10.3).

Closed Items

- Deviation 528/9506-02 was closed (Section 8.1)
- IFI 530/9420-02 was closed (Section 9.1)
- IFI 528/9426-03 was closed (Section 9.2)
- Deviation 529/9434-02 was closed (Section 9.3)
- Violation 528/9512-01 was closed (Section 9.4)
- LER 529/96-001 was closed (Section 10.1)
- LER 528/95-015 was closed (Section 10.2)
- LER 528; 529; 530/95-004, Revisions 0 and 1 were closed (Section 10.3)
- Unresolved Item 528/9506-01 was closed (Section 10.3)

Attachments:

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

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. On February 25, 1996, the main turbine tripped as a result of a lightning strike to the Main Transformer C and a reactor power cutback automatically initiated (Section 2.2). The unit was subsequently stabilized at 2 percent power for repairs to the main transformer.

On February 26, operators manually tripped the reactor following the identification of an abnormal offsite power supply lineup. On March 2, the unit entered Mode 2 following restoration of the normal offsite power supply lineup. On March 5, the unit returned to 100 percent power and remained there throughout the inspection period.

1.2 Unit 2

Unit 2 began the inspection period at 100 percent power. On February 14, 1996, all cooling fans to Main Transformer A were lost and the unit reduced power to 85 percent to reduce the heat load on the main transformer (Section 2.1). The cooling fans were restored to service and, on February 15, the unit returned to 100 percent power. On March 5, the unit began its end of core life power coastdown and ended the inspection period at 95 percent power.

1.3 Unit 3

Unit 3 began the inspection period at 100 percent power. On February 25, 1996, the main turbine tripped when Unit 1 Main Transformer C was struck by lightning. A reactor power cutback automatically initiated (Section 2.3). The unit was subsequently stabilized at 35 percent power. On February 26, the unit returned to 100 percent power and remained there throughout the inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Loss of Main Transformer Cooling - Unit 2

On February 14, 1996, the Unit 2 Main Transformer A received a high temperature alarm that was not initially recognized by the operations staff. Once the operators recognized the alarm they determined that all six banks of cooling fans and associated oil pumps had been lost. The licensee subsequently determined that a degraded transfer relay failed to transfer power for the oil pumps and cooling fans from the normal power to the alternate source. Reactor power was reduced to 85 percent to minimize heat input to the transformer. Maintenance personnel responded to the transformer

failure and restored operation of the cooling fans. On February 15, operators returned the unit to full power. The inspector reviewed the event investigation performed by the licensee. The inspector concluded that several operational weaknesses occurred during this event; however, the licensee had recognized these weaknesses and developed appropriate corrective actions.

2.1.1 Event Background

On February 14, at approximately 9:17 a.m., the control room received a main transformer trouble alarm. The reactor operator (RO) directed an AO to inspect the transformer and implemented the alarm response procedure. Operations obtained electrical maintenance engineering assistance and reset the alarm. Within the next 5 minutes, the main transformer trouble alarm actuated and reset approximately 11 times.

Operations decided to monitor the transformer and have electrical maintenance clean the relay contacts. A prejob brief was scheduled for later that afternoon. With main transformer trouble alarm actuating and resetting intermittently, the control room supervisor (CRS) authorized the RO to place the alarm in a fast flash condition which prevented future audible alarms.

At approximately 2:20 p.m., the secondary RO identified a "High Temperature" alarm to Main Transformer A on the computer screen. The AO, dispatched to the transformer, determined that none of the Main Transformer A cooling fans or oil pumps were operating.

The CRS reviewed the alarm response procedure and determined that on a loss of all cooling to the main transformer, all load must be removed within 30 minutes in order to prevent damage to the transformer. The shift technical advisor determined that the "High Temperature" alarm had actually been actuated since 1:42 p.m., approximately 38 minutes.

While electrical maintenance initiated efforts to restore cooling to the transformer, the shift supervisor (SS) began preparations to trip the turbine, and an electrical maintenance engineer manually closed the alternate supply contacts which re-energized two banks of fans. At approximately 2:38 p.m., the thermal overloads were reset, all cooling was restored to the transformer, and the main transformer winding temperature began decreasing. The SS re-evaluated the situation and determined not to trip the turbine, but to reduce reactor power to 85 percent to further assist transformer cooling. The "High Temperature" alarm cleared at approximately 3:18 p.m. The plant stabilized at 85 percent power and the licensee analyzed the transformer oil for damage. The results indicated that no damage had occurred to the transformer.

2.1.2 Licensee Response

The licensee conducted an investigation of the event, generated a condition report/disposition report (CRDR), and a human performance analysis. The

inspector reviewed the investigation and noted that the licensee's investigation identified the following issues.

- Operations response to the initial alarm condition did not meet management's expectations in that increased monitoring of plant equipment with a known degraded condition was not performed.

- A questioning attitude was not maintained by operations personnel after the initial discussion with the electrical maintenance engineer. The trouble alarm had locked in, but operators did not aggressively investigate the change in plant conditions.

- Operator control board awareness did not meet management's expectations for monitoring computer generated alarms since the source of the problem was not aggressively pursued for approximately 38 minutes.

2.1.3 Conclusions

The inspector discussed the concerns and corrective actions with the operations department leader. The inspector reviewed the licensee's corrective actions and determined they were comprehensive. The downpower and plant stabilization was well coordinated by the operations staff.

2.2 Main Transformer Lightening Strike - Unit 1

On February 25, 1996, while Unit 1 was operating at 100 percent power, the main turbine tripped followed by a reactor power cutback. An apparent lightning strike to Main Transformer C caused a generator differential fault current and subsequent main turbine trip.

The licensee declared a Notice of Unusual Event based on the observation of an apparent explosion at the transformer. The AO reported flames from the bushing at the top of the transformer. The flames self-extinguished, and the licensee terminated the Notice of Unusual Event after 14 minutes. The inspector concluded that the licensee's declaration of an Unusual Event was appropriate.

On February 26, a Unit 2 RO identified that the Start-Up Transformers NAN-X01 and NAN X02 were cross-tied, due to both the alternate and normal supply breakers being closed on the Unit 1 13.8 kV bus NAN-S06, and informed the Unit 1 control room of the problem. The Unit 1 operators verified that the alternate Supply Breaker S06F and the normal Supply Breaker S06H were closed. The operators manually tripped the reactor. Subsequent investigations determined that a computer alarm was generated immediately following the main turbine trip that indicated that two sources were paralleled.

The licensee generated a CRDR to evaluate the effects of this condition. Operators performed a shutdown of Unit 1 to Mode 3 to determine the cause of the abnormal condition and to make repairs to the Main Transformer C.

The inspector reviewed the initial investigation and concluded that operator board awareness was weak in that two different crews in two different units did not recognize the abnormal electrical configuration that had existed for approximately 18 hours. In addition, the Unit 1 operators did not recognize a computer generated alarm indicating the abnormal condition.

2.3 Main Turbine Trip - Unit 3

On February 25, the Unit 3 main turbine generator tripped due to a power load unbalance. The grid disturbance resulted from the Unit 1 main turbine trip as a result of the Main Transformer C lightening strike. The reactor power cutback system actuated and the unit stabilized at approximately 35 percent power.

The inspector responded to the main turbine trip and concluded that the operator's response to the event was appropriate and all required safety equipment operated as designed. The licensee determined that the Unit 3 subsychchronous relays were set at a lower threshold than Units 1 or 2 by design, and, therefore, Unit 3 main turbine to tripped while Unit 2 remained at power.

The licensee developed a CRDR to investigate the turbine trip and evaluate plant response. The inspector concluded that the licensee's response to the Unit 3 situation was appropriate.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 GTG Trips and Reliability

On January 23, both GTGs failed to start during a routine test. The GTGs are designed to provide the source of power to the units during a station blackout.

The licensee identified that the GTG 1 root cause of failure was a faulty air pressure regulator for the atomizing air. As an immediate corrective action, the licensee recalibrated the existing regulator and reset the output air pressure to 30 psi. In addition, the air accumulator pressure band for both GTGs was changed from 70-150 psi to 110-150 psi to increase the stability of the air regulator.

The licensee identified that the GTG 2 root cause of failure resulted from condensation in the air accumulator which blew out the flame during the start attempt. As an immediate corrective action, engineering instructed the GTG operators to blow down the GTG accumulator on a nightly basis if temperature drops below 50°F. In addition, the licensee revised the daily preoperational

checklist to include the performance of nightly blow downs of the accumulators and the revised accumulator pressure band.

The inspector reviewed the daily preoperational checklist and noted that the changes were incorporated. The inspector noted that the licensee issued a significant CRDR to evaluate the GTG reliability against target goals and to perform a failure pattern investigation. The inspector concluded that the licensee's corrective actions to address the GTG failures were appropriate.

The inspector discussed the GTG reliability with both the system and maintenance engineers. The engineers indicated that previous start failures were due to fuel setting problems and have been corrected. With the assistance from the vendor, the licensee readjusted the air assist and fuel settings. The adjustments resulted in successful starts of the GTG 2 with outside air temperatures between 34-119°F. The inspector reviewed the licensee's action plan to further increase the GTG system reliability and concluded that the licensee was appropriately addressing the issue.

3.2 EDG Problems

On January 24, 1996, during a maintenance run of EDG 1A, an AO noted fuel leaking from Cylinder 3L delivery valve holder due to a crack in the threads of the holder. The licensee contacted the vendor (Cooper Bessemer) for assistance in the evaluation of the problem. The licensee and vendor planned to further evaluate the problem for potential generic implications. The licensee concluded that there was no EDG operability concern. The inspector agreed with the licensee's operability assessment and concluded that the licensee's corrective actions were appropriate.

On February 6, the EDG 1B experienced a fuel pump pedestal failure. The licensee determined that two of the four mounting bolts holding the pedestal in place experienced fatigue failure. The licensee performed a walkdown of the other EDGs and noted no additional discrepancies. Further evaluation determined that the cause of the failure was due to a manufacturing deficiency; the holes in the engine block were not bottom tapped and, therefore, caused a false indication of bolting torque when mounting the pedestal. The licensee informed the vendor of the problem who indicated that this was the first known failure of this type. The licensee expanded the EDG vibration monitoring program to include the fuel pump and pedestal to provide an earlier warning of pedestal problems. The inspector concluded that the licensee investigation and corrective actions were appropriate.

On February 20, during the performance of a walkdown of the EDG 1A, an AO observed loose and missing bolts on the starting air manifold. Operations subsequently declared the EDG inoperable and informed the other units of the problem. Operators in Unit 3 noted that the EDG 3B also had loose bolts on the air start manifold and declared the EDG 3B inoperable. The licensee performed the Technical Specification (TS) actions for inoperable EDGs while performing an operability determination. Engineering subsequently determined that the EDGs were operable in the as-found condition. The licensee initiated

a CRDR to further evaluate the cause of the loose bolts. The licensee determined that the vendor recommended torque value for the bolts was too low. The licensee indicated that critical components have specific torque values and the remainder (such as the manifold bolts) are torqued based on a generic table. The licensee planned to discuss the issue at the next owner's group meeting and request an increased torque from the vendor. The licensee determined the event was not reportable. The inspector reviewed the justification for operability and agreed with licensee's assessment that the EDGs were never inoperable and the event was not reportable.

The inspector concluded that the licensee aggressively pursued repairs to each of the EDG component problems. In addition, the inspector concluded that the AO exhibited good attention to detail during the walkdown of the EDG.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 RTSB Failure - Unit 3

On March 6, 1996, the Unit 3 operators declared the RTSB D inoperable following the notification by electrical maintenance technicians that the undervoltage device had failed the cold voltage drop test. The purpose of the RTSB is to open upon demand, causing the control rods to be inserted into the reactor core. The electrical maintenance technician initiated a CRDR and quarantined the breaker. The licensee established an investigation team to determine the root cause of failure and develop a breaker testing action plan.

The inspector reviewed the licensee's initial root cause determination plan and the troubleshooting plan. On March 8, troubleshooting efforts concluded that the undervoltage device was experiencing binding on the trip roller. The licensee determined that the undervoltage device did not experience binding during the hot voltage drop test, which simulates actual conditions in the unit. Therefore, the RTSB would have opened if called upon. Operations declared the RTSB D operable after replacement with a spare RTSB. The licensee planned to determine the cause of binding. The inspector concluded that troubleshooting was effective and controlled and the actions taken by the licensee were appropriate.

4.2 RCP Seal Mockup

On February 28, 1996, the inspector observed mechanical maintenance engineering demonstrate the assembly of the newly designed RCP seal package. The licensee plans to perform the design change during the upcoming Unit 2 refueling outage. The newly designed RCP seal packages provide improved installation techniques to reduce personnel exposure and incorporate a passive catastrophic failure design to reduce seal leakage.

The inspectors observed the testing of the seal assembly in the static seal tester. The tester verified that the new seal packages were assembled correctly prior to placing them in the field. The tester also served as a training tool for the upcoming seal installation.

The inspectors concluded that the RCP seal package mockup and the static seal tester exhibited a proactive training effort by the maintenance department. In addition, the inspector noted that the mechanical maintenance engineer exhibited detailed knowledge of the design of the RCP seal package.

5 SURVEILLANCE OBSERVATION (61726)

The inspector observed the Valve Stroke Timing and Position Verification Surveillance test of the safety injection valves in Unit 3 and determined that testing was performed acceptably.

6 ONSITE ENGINEERING (37551)

The inspectors performed inspections of engineering activities in support of the issues related to gas turbine generators, emergency diesel generators, reactor trip switchgear breakers, and backup protection devices for containment penetrations as documented Section 3.1, 3.2, 4.1, and 10.3, respectively.

7 PLANT SUPPORT (71750)

7.1 Toxic Gas Rail Car on Owner Controlled Area

On January 9, 1996, at approximately 2:35 p.m., a rail car containing 180,000 pounds of liquified sulfur dioxide (a highly toxic gas) was brought onto the owner controlled area. On January 10, at approximately 4:45 p.m., after the licensee recognized that the toxic material was onsite, the rail car was moved to a location approximately 4.5 miles from the site. On January 11, at approximately 12:30 a.m., Southern Pacific Railroad retrieved the rail car. The inspector concluded that once the licensee recognized the potential hazard of the rail car, the licensee made aggressive arrangements to remove the rail car from the site.

The licensee identified that the root cause of the problem was that the process for receiving rail cars was not formally documented in water reclamation facility or security procedures. The licensee revised Procedure WROP-8ZZ02, "Conduct of WRF Shift Operations," to include rail car receiving operations. The inspector reviewed the procedure and concluded that the actions were sufficiently thorough to preclude recurrence.

The licensee noted that the transportation of hazardous materials by both railroad and highway may have changed since the original study that was performed in 1978. Therefore, the licensee planned to further evaluate their measures to control the introduction of toxic material into the owner controlled area and to evaluate the potential reportability of the event. The inspector concluded that the licensee responded well to the situation.

7.2 Inspection of High Radiation Areas - Unit 2

On February 15, 1996, the inspector checked the condition of the high radiation areas and locked high radiation areas in Unit 2. The inspector noted that the areas not designated for storage of high radiation materials were clean of equipment, tools, and other debris. The inspector did not observe any leaking containers in the high radiation storage area in the radwaste building. The inspector concluded that the housekeeping in the high radiation storage area was appropriate and noted that the licensee has an action plan in place to further improve the material condition of storage areas.

8 FOLLOWUP - OPERATIONS (92901)

8.1 (Closed) Deviation 528/9506-02: Failure to Follow GTG Procedures

This deviation occurred when nonlicensed operators did not perform a procedure step when operating the GTGs. As a result, a generator output breaker tripped when control room operators attempted to synchronize a GTG with offsite power.

On February 14, 1996, the inspector observed a periodic test of the GTGs and noted that the nonlicensed operators did not complete the prestart checklist specified in Procedure(s) 550P-0GT01(02), "Gas Turbine Generator 1(2) Operating Instructions," Revision 8. When questioned regarding the omission of the checklist, the nonlicensed operators told the inspector that night shift personnel performed a daily walkdown of the GTGs and completed a preoperational checklist. The inspector reviewed the preoperational checklist and found that it was not part of a controlled procedure and did not include all items of the prestart checklist from the operating instruction. The inspector concluded that, for this start, not performing the prestart checklist specified in the operating instruction was not safety significant in that the preoperational checklist covered the important parameters. The inspector noted that the checklist was not required to be performed for emergency generator starts, and the periodic test of the GTG did not involve synchronization with plant electrical systems. Through additional discussion with the nonlicensed operators, observation of their operation of the generators, and an equipment walkdown, the inspector concluded that the nonlicensed operators had a strong knowledge of the GTGs.

The inspector contacted a Water Reclamation Facility manager responsible for operation of the GTGs and expressed concerns about the adequacy of the prestart checklist and the use of the daily preoperational checklist. The manager informed the inspector that the GTG operating instructions were undergoing revision to simplify operations. On February 16, Procedure(s) 550P-0GT01(02), "Gas Turbine Generator 1(2) Operating Instructions," Revision 9, was issued. The revision substituted the daily preoperational checklist for the previous prestart checklist and specified that the checklist needed to be completed within 24 hours of any nonemergency start. The revision to the operating instructions resolved the inspector's concerns.

9 FOLLOWUP - MAINTENANCE (92902)

9.1 (Closed) IFI 530/9420-02: Policy for Entering Safety-Related Equipment

This item was opened after maintenance personnel opened an EDG control cabinet without informing plant operators and caused an alarm to be received in the control room. Following the event, the inspector questioned licensee management about their expectations for entering safety-related equipment. In response to the event, the licensee issued guidance indicating that permission was required from the releasing organization before any equipment was opened. The guidance indicated that operations was responsible for power plant equipment, with Unit 1 operations responsible for common equipment such as the switchyard and auxiliary boiler. During outages, outage control would coordinate with operations if equipment would be opened. The inspector concluded that the licensee's response to this issue was acceptable.

9.2 (Closed) IFI 528/9426-03: Adequacy of Remote Shutdown Panel Channel Checks

This item was opened after the inspector questioned the adequacy of remote shutdown panel channel checks for instruments that typically indicated zero. The licensee initiated CRDR 1-5-0147 in response to the inspector's question and determined that comparing instrument readings of different instruments, even if reading zero, was an appropriate channel check provided that the instrument showed no signs of malfunction. The inspector questioned several operating crews and found that operators looked for signs of instrument malfunction such as instrument needles on the bottom stop. The inspector concluded that the licensee's response to this issue was acceptable.

9.3 (Closed) Deviation 529/9434-02: Failure to Meet Commitments from a TS Amendment Request

The inspector reviewed the licensee's response to the Notice of Deviation, dated February 16, 1995, and verified that the corrective actions were acceptably implemented. In addition, the inspector confirmed that Unit 1 operations personnel were still responsible for coordination of work inside the switchyard.

9.4 (Closed) Violation 528/9512-01: Failure to Follow Valve Leak Test Procedure

The inspector reviewed the licensee's response to the Notice of Violation, dated August 25, 1995, and verified that the corrective actions were acceptably implemented. In addition, the inspector reviewed Procedure 73ST-9SI03, "Leak Test of SI/RCS Pressure Isolation Valves," Revision 11, dated October 11, 1995, and found that the revision appropriately changed the methodology for certain valve leak tests to what was actually being used in the plant.

10 ON-SITE REVIEW OF LICENSEE EVENT REPORTS (LERs) (92700)

10.1 (Closed) LER 529/96-001: Improper Venting of Condensate Pump Results in Loss of Feedwater Flow and Reactor Trip

The event and shutdown margin issue were discussed in NRC Inspection Report 50-528/95-25; 50-529/95-25; 50-530/95-25. The inspector further evaluated the LER and trip investigation report.

The licensee determined the loss of feedwater flow was due to improper filling and venting of the condensate pump being restored to service. The licensee identified that the operators utilized a prejob briefing and a hand written step-by-step action plan to restore the pump to service. The licensee proceduralized the filling and venting of a condensate pump with the unit at power.

The licensee identified other corrective actions and planned to review and evaluate the process of capturing critical lessons learned. In addition, the licensee planned to review the process of removal and restoration of equipment in order to determine when additional planning would be required.

The inspector reviewed the feedwater and condensate procedure and concluded that the changes to the procedure and additional corrective actions were appropriate.

The licensee identified that the operators were unaware of the loss of the second feedwater pump and the decrease in steam generator water level which subsequently led to a reactor trip. The licensee concluded that improvements were needed in the area of board monitoring during plant transients. In addition, the licensee noted that management's expectations were to trip the reactor when plant protection setpoints are trending towards trip values. The inspector reviewed the trip investigation and noted that the corrective actions for board monitoring and manually tripping of the reactor were not addressed.

The inspector discussed operator board monitoring with the operations director. The operations director indicated that he is evaluating the corrective actions for the board monitoring issue through an Executive Vice-President, Nuclear, Level 1 action item. The inspector concluded that the corrective action was appropriate.

The inspector reviewed the previous feedwater transients that resulted in a unit trip. The inspector noted that in the past 3 years, nine reactor trips occurred due to feedwater transients. The inspector identified that all the trips were automatic and none were manually initiated by the operators. The inspector noted that management's expectations and Procedure Guidance 40AC-90P02, "Conduct of Shift Operations," directs the CRS to order a manual reactor trip when the trip setpoints are approached and it is unlikely that manual intervention by an operator or automatic system operation will prevent exceeding the setpoint.

The inspector discussed the observation that operators are not manually tripping the unit when trip setpoints are approached with the operations director. The operations director indicated that an evaluation of management's expectations for providing specific guidance on taking manual control of automatic functions and manual tripping of the reactor is an ongoing corrective action from the November 26, 1995, Unit 1 reactor trip. In addition, management has been reviewing operator performance on the simulator in situations requiring a reactor trip.

The inspector concluded that the licensee's actions to evaluate and clarify management's expectations for tripping the unit were appropriate.

10.2 (Closed) LER 528/95-015: Main Steam Isolation Bypass Valve Manual Actuator Found Locked in a Nonneutral Position

On December 20, 1995, the main steam isolation valve Bypass Valve SGE-UV-169 failed to fully close during surveillance testing. The licensee declared the bypass valve inoperable and entered the TS action statement. The licensee discovered that the manual operator for the bypass valve was locked in a nonneutral position, preventing the full automatic closure of the valve. Licensee personnel restored the bypass valve manual operator to a neutral position and demonstrated operability of the bypass valve.

10.2.1 Event Description Background

On May 5, 1995, the licensee checked the proper position of the bypass valve during locked valve verification following the refueling outage. On June 17, the licensee identified a packing leak on the bypass valve. On July 13, the operators successfully reduced the steam leak by placing the normally closed bypass valve on the open backseat. On November 26, the unit tripped, received a main steam isolation signal, and the bypass valve automatically closed as designed. The licensee reopened the bypass valve during the subsequent unit startup. On December 3, the bypass valve properly closed during surveillance testing. On December 20, the valve failed to fully close during surveillance testing. The licensee concluded that the valve manual operator was repositioned between December 3 and December 20. Upon review of the sequence of events, the inspector agreed with the licensee's conclusion regarding when the valve was repositioned.

10.2.2 Investigation and Corrective Actions

The licensee inspected other valves with similar manual operators and verified that they were all in their proper position. The licensee initiated an investigation team to evaluate the cause of the event. The investigation team reviewed records and interviewed operations and maintenance personnel having access to the bypass valve. The investigation team could not validate the use of the manual operator to reposition the bypass valve.

On December 28, 1995, the licensee disassembled and inspected the manual operator to identify any defective components or possible cause of failure

that could lead to the repositioning. The licensee did not identify any deficiency or potential failure mechanism that would result in the manual operator moving to the as-found position of the bypass valve.

The licensee noted that new locking seals were normally kept in the control room under the control of the SS or the CRS. The licensee indicated that personnel stated that new seals have been seen unattended outside the control room in the past. The investigation team did not locate any unattended seals. The inspector questioned operators and they indicated that the AOs have possessed new seals in the past. The licensee issued a night order to reemphasize the requirement for shift supervision to control a working inventory of new locking seals and that extra seals would be kept in locked storage. The inspector noted that a working inventory of new seals was kept in the control room with spares locked in a cabinet.

10.2.3 Assessment of the Safety Consequences of the Event

The licensee performed an assessment to determine the safety consequences and implications of the event and determined that the event did not result in any challenges to the fission product barriers or result in any release of radioactivity. The licensee concluded that there were no adverse safety consequences as a result of the event.

The inspector reviewed the licensee's safety analysis evaluation and discussed the analysis with licensee personnel. The inspector reviewed the emergency operating procedures and noted that the procedures address the failure of the bypass valve to close in both the excessive steam demand procedure and a steam generator tube rupture procedure. The inspector concluded that the event had minimal safety significance.

10.2.4 Conclusions

The inspector concluded that the licensee's investigation and subsequent corrective actions were effective in addressing the issue. The licensee failed to comply with Technical Specification 3.6.3 in that Main Steam Isolation Bypass Valve SGE-UR-169 was not capable of automatic closure for some indeterminate period of time greater than 4 hours between the dates of December 3 and 20, 1995. This licensee identified and corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy (528/9602-01).

10.3 <u>(Closed) LER 528; 529; 530/95-004, Revisions 0 and 1: Containment Electrical Penetration Overcurrent Protective Devices Outside Design Basis; and (Closed) Unresolved Item 528/9506-01: Notice of Enforcement Discretion for Penetration Overcurrent Protection - Units 1, 2, and 3</u>

10.3.1 Overview

On March 30, 1995, the licensee requested that the NRC grant two Notices of Enforcement Discretion (NOEDs): one for Units 2 and 3 TS 3.6.3, "Containment Isolation Valves," and one for Unit 1 TS 3.8.4 "Containment Penetration Conductor Overcurrent Protective Devices." The request was granted by the NRC Region IV office the same day.

10.3.2 Notice of Enforcement Discretion

Design engineering had determined that 34 containment electrical penetration circuits in each unit did not meet Regulatory Guide 1.63 and Institute of Electrical and Electronics Engineers Standard 317-1976. These standards required that two protective devices be installed in electrical circuits penetrating containment if the maximum fault current exceeds the thermal rating of the penetration. One protective device was considered adequate for those circuits in which the maximum fault current did not exceed the thermal rating of the penetration. During a design review, design engineering discovered that errors had been made in the original design calculations for maximum fault current. The engineers determined that 34 containment penetrations which had been installed with only one protective device had recalculated maximum fault currents that exceeded the penetration ratings. Based on engineering's findings, the licensee concluded that these 34 containment penetration circuits were inoperable.

While the licensee added a second protective device to most of the circuits within the action times of the TS requirements, a few circuits could not be modified within the action times. Because Unit 1 was in the process of shutting down for a refueling outage, TS compliance was different for this unit.

The licensee requested two NOEDs (Tracking 95-4-002 and 95-4-003) to allow additional time to add backup protection to the remaining circuits. Details of these NOEDs and the circuits covered were discussed in NRC Inspection Report 50-528/95-06; 50-529/95-06; 50-530/95-06. The NRC approved both NOED requests based on the minimal safety significance and the compensatory measures implemented by the licensee.

10.3.3 Licensee Reports

The licensee issued LER 95-004, Revisions 0 and 1, to describe the problem in detail and document corrective actions. During subsequent reviews, the licensee identified six circuits that had backup protection for containment penetrations; but, the protective devices were not being tested per TS 4.8.4.1 due to their omission from the TS during either initial TS preparation or old design changes. The licensee subsequently tested these six circuits.

The licensee added backup protection to all required circuits or deenergized and tagged the circuits, pending the addition of backup protection. The

licensee reported that they would continue to review original design calculations.

10.3.4 Inspector Review

The inspector reviewed LER 95-004, CRDR 9-5-0189, and portions of Calculation 13-EC-NA-222, Revision 1, "Electrical Penetration Protection." The inspector also compared a sample of the calculations to licensee design drawings to verify that the calculation assumptions for circuit configurations were consistent with the drawings.

The inspector reviewed the calculations and noted that they were based on very conservative assumptions. For example, maximum fault current for 120 volt alternating current circuits were originally calculated using minimum circuit resistances. The new calculations noted that, for a line to ground fault, the ground leg could have a lower resistance than the normal return circuit. So for new calculation purposes, the ground leg resistance was considered to be 0 ohms. With this change, circuits with previously calculated maximum fault current slightly below a penetration rating now had calculated maximum fault current slightly above the rating.

10.3.5 Conclusion

The inspector concluded that:

- All the circuits originally had at least one properly coordinated containment penetration protective device.
- The new calculations, which indicated a need for backup penetration protection, were based on very conservative assumptions.
- The calculation circuit design assumptions matched the design drawings.
- The calculations were correctly performed using industry standards for fault current calculations.
- For the six circuits that had backup protection, but were not adequately tested, only one protective device in each circuit required additional testing.

Based on the above information, the inspector considered that there was little safety significance for the lack of backup overcurrent protection and that the licensee's corrective actions were appropriate. The inspector concluded that the root cause of the problems was a lack of adequate design control oversight of old design documents, resulting in the failure to detect calculation errors and TS omissions. The inspector also concluded that the calculation errors and TS omissions, which were discovered by the licensee's voluntary calculation reverification program, would not have been discovered by routine licensee activities. Therefore, this licensee identified and corrected

violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," which would have been classified as a Severity Level IV violation, is being treated as a noncited violation, consistent with Section VII.B.3 of the NRC Enforcement Policy (528, 529, 530/9602-02).

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Arizona Public Service Company

*J. Bailey, Vice President, Nuclear Engineering
*B. Chapin, Department Leader, Mechanical Maintenance
*R. Flood, Department Leader, System Engineering
*B. Grabo, Section Leader, Nuclear Regulatory Affairs
*R. Hazelwood, Engineer, Nuclear Regulatory Affairs
*R. Henry, Site Representative, Salt River Project
*A. Krainik, Department Leader, Nuclear Regulatory Affairs
*D. Mauldin, Director, Maintenance
*W. Montefour, Senior Representative, Strategic Communications
*G. Overbeck, Vice President, Nuclear Support
*C. Seaman, Director, Nuclear Assurance
*M. Shea, Director, Radiation Protection
*J. Taylor, Department Leader, Unit 3 Operations
*J. Velota, Director, Training

1.2 NRC Personnel

*D. Kirsch, Chief, Reactor Projects Branch F
*D. Garcia, Resident Inspector

1.3 Others

*F. Gowers, Site Representative, El Paso Electric
*R. Henry, Site Representative

The personnel listed above attended the exit meeting. In addition to these personnel, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

The inspectors conducted an exit meeting on March 6, 1996. 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 inspection report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

LIST OF ACRONYMS

AO	auxiliary operator
CRDR	condition report/disposition report
CRS	control room supervisor
EDG	emergency diesel generator
GTG	gas turbine generator
IFI	inspector followup item
LER	licensee event report
NOED	Notices of Enforcement Discretion
RCP	reactor coolant pump
RO	reactor operator
RTSB	reactor trip switchgear breaker
SS	shift supervisor
TS	Technical Specification