ENCLOSURE 1

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/95-21
50-529/95-21
50-530/95-21

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

Inspection Conducted: November 5 through December 16, 1995

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Approved: D. F. Kirsch, Chief, Reactor Projects Branch F — Date 1/10/96

Inspection Summary

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

Results (Units 1, 2, and 3):

Operations

- Operator response to a Unit 1 loss of load transient and subsequent reactor trip and main steam isolation was adequate. However, operations management plans to review expectations and guidance to operators concerning taking manual control of automatic systems and when to initiate manual scrams (Section 2.1)

- An auxiliary operator, attempting to close a pneumatically operated condenser vacuum breaker, did not meet licensee expectations in that he

did not inform the control room prior to taking actions, nor had he previously identified an apparent deficient condition (Section 2.2).

- Operators performed Unit 3 midloop operations in a controlled manner. The use of a designated midloop operating crew was seen as a strength (Section 4.1).

- The licensee's evaluation of previous reactor startup reactivity control weaknesses was found to be an indepth and critical evaluation. The training developed to address these weaknesses was creative and thorough (Section 4.4).

Maintenance/Surveillance

- Although the Unit 2 Train B emergency diesel generator experienced another non-safety related trip during a surveillance test, it was noted that the team established to investigate these problems had made considerable progress and had developed an indepth understanding of the systems which were causing these trips (Section 5.1).

- Mechanical maintenance efforts to investigate and repair the Unit 2 Train A charging pump were seen as a strength (Section 5.2).

- Mechanical maintenance efforts to troubleshoot and repair the Unit 3 turbine driven auxiliary feedwater pump were well planned, well controlled, and provided with appropriate management oversight (Section 5.4).

- The inservice test procedure for the containment spray pump had instrumentation correction factors which were in error. Subsequent licensee investigation determined that several other inservice tests had less significant correction factor errors (Section 6.1).

Engineering and Technical Support

- Problems experienced with refrigerant levels in the essential chillers in Units 1 and 3 did not appear to be well understood. It did not appear that clear and consistent guidance had been provided for both refrigerant levels and oil levels during cold weather operation of the chillers (Section 5.5).

- Management made a conservative decision to perform an on-line test of a Unit 2 letdown isolation valve to resolve remaining operability concerns (Section 9.1).

- The licensee identified that data communicated by maintenance technicians to engineers performing an operability determination for letdown isolation capabilities was in error in a non-conservative direction (Section 9.1).

Plant Support

- The inspectors observed that the Unit 3 containment, following the licensee's containment restart closeout inspection, was not as clean as has been observed in the past, although the size and amount of debris was not sufficient to render any safety systems inoperable (Section 4.2).

Summary of Inspection Findings:

- One unresolved item (529/9521-01) was open concerning problems experienced with the essential chillers in Unit 1 and Unit 3 (Section 5.5).

- One unresolved item (528/9521-02) was opened concerning a condition potentially outside the design basis which could lead to the turbine driven AFW pump tripping on overspeeed (Section 7.2).

- One non-cited violation was identified concerning inadequate inservice testing procedures for the Unit 3 containment spray pump (Section 6.1).

- One non-cited violation was identified concerning the failure of operators to follow procedures when removing the Unit 1 Train N Auxiliary Feedwater pump from service (Section 8.1). This closed Unresolved Item 528/9514-02.

- Unresolved item 528/9431-01 was reviewed and remains open (Section 9.1).

- Licensee Event Reports 528/93-011, Revision 1 and 528/95-001, Revision 0 were closed (Section 10.1).

Attachments:

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

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. On November 26, 1995, a reactor trip occurred following a loss of condenser vacuum (Section 2). The unit was returned to 100 percent power operation on December 1.

On December 7, reactor power was reduced to 40 percent to identify and isolate a potential circulating water leak into Condenser Hotwell 1C. On December 9, a reactor trip occurred after a startup transformer tripped (Section 3). On December 13, the unit was returned to 100 percent power operation and operated at this power for the remainder of the inspection period.

1.2 Unit 2

Unit 2 began the inspection period at 100 percent power and operated at this power for the remainder of the period.

1.3 Unit 3

Unit 3 began the inspection period with the core offloaded to the spent fuel pool. On November 6, the unit began the core reload and entered Mode 6. On November 28 the reactor was taken critical. On November 30, the unit ended a site record 47 day refueling outage and synchronized to the grid. The unit ended the inspection period at 100 percent power.

2 REACTOR TRIP FOLLOWING A LOSS OF CONDENSER VACUUM - UNIT 1 (93702, 71707)

On November 26, Unit 1 experienced a main turbine trip from 100 percent power when a condenser vacuum breaker failed open causing a low vacuum turbine trip. Following a seven minute loss of load transient, a high steam generator level condition initiated a reactor trip and a main steam isolation signal. During the initial loss of load transient, steam bypass control valves to the condenser were only available for the first 13 seconds, due to their closure by condenser vacuum protection logic. After closure of the steam bypass control valves to the condenser, secondary pressure increased and three main steam safety valves lifted. One of the main steam safety valves remained open following the reactor trip and subsequently reopened at approximately five percent below its set pressure. The inspector's review of the licensed operator response to the transient is discussed in Section 2.1.

During the event and during subsequent post-trip recovery, the unit experienced several equipment problems. These included the following:

- The condenser vacuum breaker to the C hotwell spuriously opened (Section 2.2).

- Although Main Steam Safety Valve 561 opened within one percent of its set pressure, it remained open for approximately 11 minutes and reset at a pressure below its expected blowdown range. It subsequently reopened at a pressure approximately five percent below its setpoint (Section 5.3).

- When operators attempted to start the Train N auxiliary feedwater (AFW) pump, it tripped on low suction pressure.

- Unrelated to the trip, the Train B essential chiller tripped on low refrigerant temperature (Section 5.5). The Train B AFW pump was declared inoperable since this essential chiller provided cooling for the AFW pump room. As a result, Technical Specifications required the licensee to enter Mode 4.

- After the licensee removed the Train N AFW pump low suction pressure trip from service, they could not reopen the downcomer isolation valves, which had automatically closed on the main steam isolation signal (Section 2.3).

2.1 Operator Response to the Turbine Trip and Reactor Trip Transients

The licensee initiated an incident investigation team, lead by Nuclear Assurance, to review the cause of the reactor trip and the operator response. The inspector performed an independent review of the event and interviewed the control room supervisor and shift supervisor. The inspector discussed the preliminary results of the licensee's investigation with their team on December 12. The licensee's preliminary conclusion was that operators had performed properly and had met management expectations. The inspector discussed concerns regarding the following issues:

- Operators opened the atmospheric dump valves to control the secondary pressure transient approximately four minutes into the event.

- The slow response of the feedwater control system (FWCS) appeared to contribute to the high steam generator level condition.

- A high level over-ride (HLO) signal, which terminates feedwater flow on high steam generator level, appeared effective in one steam generator and not in the other.

- Instruments indicated that reactor trip setpoints were approached in three instances and operators did not manually trip the reactor.

- Following the reactor trip, it appeared that secondary pressure and primary temperature exceeded emergency operating procedure guidance.

2.1.1 Atmospheric Dump Valve Control

The steam generator atmospheric dump valves (ADVs) used at Palo Verde operate solely on the demand signal manually positioned by the operators. The ADVs do not have an automatic capability to relieve steam generator pressure and take approximately 30 seconds to open after operators position their controller.

The inspector noted that the main steam safety valves, which first lifted approximately one minute into the event, were open for approximately two minutes before the operators opened the ADVs. The inspector discussed the delay in opening the ADVs with the licensee. The licensee stated that the operators had been trained with an operating philosophy that manual action should only be taken once the transient cause is understood. They noted that during the time the safety valves were open, the operators had focused on reactor coolant system (RCS) pressure, which was also high. In addition, the secondary side operator was evaluating the loss of condenser and the loss of six of the steam bypass control valves. The licensee indicated that although the operator response to open the ADVs was not quick, the licensee determined the operator response had met their expectations. The inspector agreed with this assessment.

2.1.2 Steam Generator Level Control

The inspector reviewed several parameter trends to evaluate the cause of the high steam generator (SG) level reactor trip. The inspector compared feedwater flow to reactor power and noted that the feedwater flow to each SG was approximately 500 gallons per minute (gpm) greater than the amount required for the given reactor power. In addition, the inspector noted a slow SG level increase.

The inspector noted that the operators had not expected a feedwater transient and had not recognized that the SGs were being overfed until late in the transient. Approximately 30 seconds before the reactor trip, the operators closed the SG economizer isolation valves to limit any leakage past the economizer control valves. However, the operators did not take manual control of the feedwater system to control the feedwater flow before the high level trip occurred.

The inspector reviewed the system description manual for the FWCS. The inspector noted that the FWCS has a lag network to effectively delay the complete implementation of a level deviation signal in single element control (power less than 15 percent). The inspector questioned engineering about the response of the single element FWCS during the plant transient. The engineer indicated that the system was not designed to handle the transient that was experienced on November 26. The system was designed to be slow, and not overreact, to allow stable operation during reactor startups. The engineer indicated the FWCS responded as designed.

The inspector discussed the overfeeding observation and FWCS response in single element control with the licensee's incident investigation team. The team reviewed the inspector's findings and evaluated the trends. The licensee subsequently determined that the FWCS was not designed to mitigate this event before the SG water level reached a reactor trip setpoint.

The licensee determined that, in single element control, the FWCS was designed for power changes of up to one percent per minute. Actual power had been changing at approximately two percent per minute. The licensee determined that, in three element control, the FWCS was designed for power changes of five percent per minute. Actual power had been changing at approximately eight percent per minute when in three element control.

The inspector questioned several operators in all three units about their knowledge of the FWCS in single element control. The inspector noted weaknesses in the operators' knowledge of the limitations of the FWCS. The inspector found that operators expected the FWCS to be responsive in single element control and that they were not aware of the limits of the FWCS in single element control. The inspector noted that operator training seldom includes plant operational transients at low power operations. In addition, during plant shutdowns, plant operators manually trip the reactor from approximately 20 percent power and, therefore, single element control is not utilized.

The inspector discussed the operators' knowledge of the FWCS with the licensee. The licensee's investigation team had determined that operators had responded appropriately during the event. They had noted that the event was complex with several parameters in transient conditions throughout the event. They concluded that these conditions would have made it difficult for operators to conclude what manual actions, if any, were appropriate. However, they indicated that they would evaluate the licensed operator knowledge of the FWCS and determine if additional training of the FWCS limitations at low power may enhance operator performance. The licensee also planned to evaluate the current FWCS design and determine if it can be improved or optimized.

2.1.3 Steam Generator High Level Override

The inspector noted that the function of the HLO was to close the feedwater economizer and downcomer valves when the level in the affected SG reached 88 percent to prevent excessive moisture carryover to the main turbine. The reactor trip and main steam isolation signals are set at 91.5 percent level.

The inspector reviewed the post trip sequence of events and noted that approximately two minutes prior to the reactor trip on high level in SG 11, the operators had a high level in SG 12. The inspector found that the HLO isolated feedwater to SG 12 and prevented the reactor trip. The inspector noted that the HLO for SG 11 occurred three seconds before the reactor trip on high level in SG 11. The HLO did not prevent an automatic safety function actuation in the three second time span.

The inspector discussed the HLO response with the licensee's incident investigation team. The incident investigation team indicated that the HLO responded as designed and that the as found setpoint was within the setpoint tolerance. The inspector questioned whether the HLO was nonfunctional since it failed to isolate feedwater flow to the SG 11 before the reactor trip and main steam isolation occurred. The incident investigation team indicated that they would review the setpoint and setpoint tolerance to determine if the setpoints or function could be enhanced to prevent reactor trips. The inspector concluded that the licensee action to further evaluate the HLO design was appropriate.

2.1.4 Manual Operator Actions

The inspector noted that the shift supervisor and control room supervisor discussed manually tripping the reactor three times during the event. The first time occurred when the pressurizer pressure increased to the pretrip setpoint; however, pressure turned and remained under control. The second time occurred when SG 12 high level increased to the high level pretrip; however, the HLO turned the SG level. The third time occurred when SG 11 high level increased to the high level pretrip setpoint; however, the reactor automatically tripped before the operators could manually trip the reactor.

Licensee management stated that operators had appropriately implemented the expectations that manual action not be taken if it appeared that control systems were responding appropriately. The inspector noted that licensee management planned to evaluate management's expectations for taking manual actions including manual control of automatic control systems during plant transients. The inspector concluded that the licensee's corrective actions were appropriate. In addition, the licensee planned to evaluate their guidance to operators on when to initiate a manual trip.

2.1.5 ADV Control Following the Reactor Trip and Main Steam Isolation

The inspector noted that following the reactor trip, the reactor coolant system temperature and steam generator pressure gradually increased for approximately four minutes before the operator reduced the steam generator pressure to allow the open main steam safety valve to close. In addition, RCS temperature and steam generator pressure increased to above the band specified in emergency operating procedures. The inspector discussed the secondary operator's performance in controlling plant parameters with the licensee. The licensee reviewed the post trip trends and discussed the requirements for plant control that training uses to evaluate operator performance on the simulator. The licensee determined that the operator performance was satisfactory, but not optimal. The inspector agreed with the licensee's assessment of the performance.

2.2 <u>Spurious Opening of the Condenser Vacuum Breaker</u>

The condenser has three vacuum breakers. They are air to open, spring to close butterfly valves that can be opened from the control room. Prior to the

event, an auxiliary operator (AO) was touring the turbine building and had just ensured that the vacuum breaker for the C hotwell had an adequate water seal on its upstream side when he heard a "loud sucking noise" from the vacuum breaker. He observed that the vacuum breaker was in the mid-position instead of the required closed position. He took control of instrument valves on the actuator and eventually closed the breaker, although his action caused the vacuum breaker to open slightly farther than it already was for a short period of time.

The inspector reviewed the licensee's evaluation of the AO's performance and the evaluation of the cause of the failure.

2.2.1 Auxiliary Operator Performance

The licensee concluded that the AO should have contacted the control room prior to attempting to close the vacuum breaker. The licensee noted that AOs were not trained in the operation of the vacuum breaker actuator. Operations management stated that it was their expectations that the AO contact the control room prior to taking actions in the field on equipment that the AO did not have either written instructions or had not had specific training.

The licensee's investigation team found that the AO had previously observed that there appeared to be leakage past the solenoid, and that this condition was not observed on the other vacuum breakers. However, the AO had not initiated a work request to have the condition investigated, as expected by management.

The licensee planned to review this event with the AOs and reinforce the appropriate requirements expected of the AOs before and after taking action in the field. In addition, the licensee planned to evaluate the current task analysis and training for AOs and determine whether additional training was warranted to enhance knowledge of air operated valves and actuators similar to the vacuum breaker operator.

2.2.2 Vacuum Breaker Failure

The licensee determined that the apparent cause of the vacuum breaker solenoid failure was attributed to component age. The licensee inspected the solenoid valve and noted that the middle insert gasket (O-ring) within the solenoid appeared degraded and flat. The seating surfaces on the piston/guide subassembly also showed indications of wear.

The licensee checked the other vacuum breaker solenoid valves for leaks and noted two additional solenoid valves in Unit 2. As an interim corrective action, these valves were replaced. Valve Services Engineering planned to perform a root cause analysis of the solenoid valves. Based on the results of the analysis, the licensee planned to make a determination of any preventative maintenance requirements or recommend an alternative corrective action.

2.3 Downcomer Isolation Valves Failed Closed

On the day after the reactor trip, with Unit 1 in Mode 4, the licensee completed actions to disable the low suction pressure trip for the Train N AFW pump and successfully started and ran the pump. Operators proceeded with actions to place the Train N AFW pump inservice.

The Train N AFW pump provides condensate storage tank water to the upstream side of the downcomer feedwater control and isolation valves. The Train A and B AFW pumps provide condensate storage tank water downstream of these valves. For each steam generator, there are two (spring to close, air to open) isolation valves which close on a main steam isolation signal. When operators attempted to open the downcomer isolation valves, they could only get one out of three open and could not establish flow from the Train N AFW pump to either steam generator.

Operators, with the assistance of the shift technical advisor, attempted various combinations of venting the upstream and downstream pressures. After troubleshooting for four hours, they were able to open the remaining three downcomer isolation valves when they established discharge pressure of the Train N AFW pump to the upstream side of the valves.

At the end of the inspection period, the licensee had not established a root cause of the failure to open. The inspector noted that Technical Specification 3.7.1.2 for the AFW system required that the Train N AFW pump and its associated flow path were required to be operable. On December 12, the inspector requested the licensee to explain why they considered the Train N AFW pump flow path operable in light of the problems experienced following the reactor trip.

On December 15, in a conference call with the Region IV management, the Site Shift Manager stated that the flow path was considered operable since the downcomer isolation valves could be opened with the assistance of the discharge head of the Train N AFW pump. The Region IV staff questioned whether this sequence was explicitly covered in operating instructions. The licensee noted that operating procedures allowed this sequence, but did not specifically require it. They stated that a night order would be issued to all units discussing the downcomer event and the success path used by the Unit 1 operators to open the valves.

The inspector subsequently reviewed the night order and found that it discussed the failure of the downcomer valves to open, speculated that it was caused due to pressure binding, and noted that applying pressure from the Train N AFW pump to the downcomer isolation valves had allowed operators to open the valves.

The licensee concluded that they had a high degree of confidence that with or without the night order, plant operators could have opened the downcomer valves in similar circumstances. To assess the validity of this conclusion, the inspector discussed the night order with control room supervisors and

shift supervisors in all three units. The inspector noted that prior to the night order, the supervisors in Units 2 and 3 were aware that there had been problems with the downcomer valves in Unit 1, but were not cognizant of the success path for opening the valves. The inspector found that although the night order did not provide specific instructions, each supervisor appeared to understand its message. Additionally, the supervisors interviewed appeared confident that they would have taken this course of action if the night order had not been provided.

The inspector found that while there appeared to be reasonable basis for the licensee's assertion that other crews could have reopened the downcomer isolation valves in a timely manner, the night order to communicate this issue was prudent.

The inspector noted that the licensee was investigating the cause of the valve failures. At the end of the inspection period, the licensee considered that pressure binding of the flex-wedge gate valves to be a probable cause. Additionally, the licensee was evaluating the design basis for these valves to establish their function to support the Train N AFW flow path. The inspector will review the licensee's root cause evaluation in a future inspection.

2.4 Conclusions

The inspector concluded that the licensee's actions, both completed and planned, to assess this event and its implications were appropriate.

3 REACTOR TRIP FOLLOWING STARTUP TRANSFORMER TRIP - UNIT 1 (93702, 71707)

On December 9, the Unit 1 reactor tripped from 40 percent power on low steam generator level. Two minutes prior to the trip, a ringtail cat (a desert mammal similar to a raccoon) caused a momentary phase to ground path on the startup transformer NAN-X03, which resulted in a loss of power to the Unit 1 bus PBA-S03 (vital Train A 4160 volt) and the Unit 2 bus PBB-S04 (vital Train B 4160 volt). Both the Unit 1 Train A diesel generator and the Unit 2 Train B diesel generator started and operated as expected.

In Unit 1, the 120 volt ac control power bus NNN-D11, which supplies the FWCS and the steam bypass control system, failed to complete an automatic transfer from its "alternate" power supply bus PBA-S03 to a "normal" non-class power supply, causing a loss of power to bus NNN-D11. As a result of the loss of power to the FWCS, the main feedwater pumps went to minimum speed and feedwater control valves closed, causing steam generator levels to decrease. Steam generator 12 level decreased below the reactor trip setpoint, resulting in a reactor trip.

The licensee classified the event as an "uncomplicated trip" and all systems responded as expected. Bus NNN-D11 was re-energized when it automatically transferred back to bus PBA-S03 after its auxiliary transformer powered normal power supply de-energized as a result of the turbine trip. In addition, two reactor coolant pumps and two circulating water pumps tripped following the

turbine trip since they could not fast transfer from the auxiliary transformer to startup transformer NAN-X03. This resulted in a loss of condenser vacuum and the unavailability of six of eight steam bypass control system (SBCS) valves. Secondary side pressure rose to 1246 psia and one main steam safety valve lifted and relieved for approximately two minutes. The licensee subsequently determined that the safety valve lifted and reset within its design margins.

The licensee determined that a mechanical linkage problem prevented bus NNN-D11 from completing its transfer sequence from its alternate power supply to its normal power supply, as explained below. The licensee has had bus NNN-D11 aligned to its alternate power supply since initial startup. During the post-trip review, the licensee determined that it would be preferable to re-align NNN-D11 to its normal power supply and confirmed through testing that it would reliably automatically transfer from its normal to alternate power supply.

On December 11, at 0605, Unit 1 went critical and returned to full power on December 13. Unit 2 remained at 100 percent power throughout the event. The resident inspectors responded to the site following the reactor trip and followed the licensee's initial post-trip review.

On July 17, 1995, Unit 2 experienced a similar event when a breaker operation error resulted in the loss of 13.8 Kv bus NAN-S05. During this event, NNN-D11 transferred correctly from its alternate supply to its normal supply. However, the transfer was designed as break before make and, as a result, during the brief period the bus was de-energized, the FWCS switched to manual with zero demand. This event was discussed in Inspection Report 95-14 and Licensee Event Report (LER) 50-529/95-05.

During the initial post-trip review following the Unit 2 trip, the licensee suspected that bus NNN-D11 had not properly transferred. They subsequently discovered that it had transferred as designed. They concluded that an initial design of the bus transfer did not provide for uninterrupted power to NNN-D11, resulting in an inconsistent transfer of the FWCS and the SBCS. The licensee had established a December 29, 1995, due date for modification recommendations to address this design weakness. At the time of the Unit 1 trip, the licensee had completed most of their review, but had not finalized their recommendations.

In their review of the bus NNN-D11 transfer logic, the licensee determined that the original design required the bus be supplied by the auxiliary transformer, through bus NAN-S01. However, during initial plant startup, the licensee had established a practice of lining up the bus to its alternate source, from bus PBA-S03. This change was apparently made after reliability problems with the automatic fast bus transfer, between bus NAN-S01 (supplied by the auxiliary transformer) and bus NAN-S03 (supplied by the startup transformer), caused frequent challenges to the bus NNN-D11 transfer. At the time, the alternate supply was considered a more reliable power source.

On December 9, the licensee determined that aligning bus NNN-D11 with its normal supply was preferable to aligning it with its alternate supply. They noted that in recent years power had been interrupted on the startup transformers more frequently than on the auxiliary transformers. Additionally, the fast transfer of the 13.8 Kv buses had worked reliably. The licensee also noted that further efforts to address the reliability of power to sensitive non-vital AC instrument and control loads were still in progress.

4 OPERATIONAL SAFETY VERIFICATION (71707)

4.1 Midloop Operations - Unit 3

On November 15, the inspector observed several aspects of the midloop performance. The inspector observed that the control room staff maintained positive control of the evolution. The inspector noted that the licensee had again used two control room supervisors from another unit, who had been involved in recent midloop operations, to supervise midloop operations in Unit 3. The continuity established appeared to be effective.

The inspector reviewed the refueling water level indicating system (RWLIS) instrumentation calibration and noted no discrepancies. The inspector performed a walkdown of the RWLIS inside containment and noted that the system was properly aligned.

The inspector noted one of the RWLIS instrument tubing supports was loose. The inspector informed the licensee of the problem. The licensee promptly corrected the deficiency. In addition, the inspector noted that the condition of work areas and the general housekeeping in containment were not as good as the inspector observed in previous outages. The inspector informed the licensee about the observations. Maintenance management determined the major contributor to the problem was contract workers and took actions to correct the work practices. The inspector concluded that the licensee's response to the deficiencies was appropriate.

4.2 Containment Closeout Inspection - Unit 3

On November 22, the inspector performed a containment closeout inspection. The inspector found several small debris items and noted that the containment cleanliness was not as good as it has been observed in the past. The inspector noted that the reactor coolant pump bays contained the majority of the debris. The items discovered in containment included: tape, plastic, tie wraps, and leather gloves. The inspector concluded that the size and volume of the items would not impact the containment sumps and, therefore, the debris items did not constitute a safety concern.

The inspector discussed the observation with the licensee. The licensee performed additional walkdowns prior to startup. The licensee planned to evaluate the inspector's walkdown findings prior to the next refueling outage.

4.3 Use of Computer to Monitor Changing Plant Conditions - Unit 3

On November 17, the inspector observed a start of a reactor coolant pump in a solid plant condition. The inspector noted that the operators reviewed the reactor coolant pump operating procedure and discussed when the pump should be manually tripped before RCS pressure decreased below the minimum net positive suction head (NPSH) pressure requirement. The inspector noted that the operator used the emergency response facility data acquisition display system (ERFDADS) to monitor a single suction pressure value. The inspector monitored the pressure transient on the four safety channels of pressurizer pressure. During the pump start, the inspector noted that the pressure dropped below the minimum NPSH pressure for the pump before the pump tripped on an unrelated speed sensor failure. The inspector noted that the ERFDADS pressure monitored by the operator still indicated adequate NPSH pressure when the pump tripped.

The inspector questioned the ERFDADS response with the system engineer. The system engineer indicated that the ERFDADS has a minimum of a 1.5 second delay compared to the analog safety channel indication. The inspector informed the operations department leader of the observations and expressed a concern that the operator used a time delayed indication in a transient condition. The operations department leader agreed with the inspector and issued a night order to all operators indicating that ERFDADS should not be solely used for indication during a transient condition. The inspector concluded that the use of the ERFDADS in this instance had no safety impact on the plant and that the licensee's corrective actions were appropriate.

4.4 Approach to Criticality Process Review

The inspector reviewed the licensee's corrective actions in response to inspector identified weaknesses in the licensee's performance of 1/m plots for monitoring the approach to criticality during a Unit 2 reactor startup (Inspection Report 95-14). The inspector noted that the licensee evaluated crew performance, including the shift technical advisor and reactor engineering, during several plant startups on the simulator. The licensee identified performance and knowledge weaknesses of both the crew and the training staff. The licensee initiated a condition report/disposition request (CRDR) to evaluate and correct the weaknesses. The inspector concluded that the licensee performed an extremely thorough and indepth assessment of the weaknesses in both the performance of personnel and the startup process.

At the exit meeting, the inspector noted that the licensee's review of the startup process identified a need for continued training on complex evolutions that are performed infrequently. The licensee agreed with the inspector's statement and planned to continue evaluating operator training requirements.

5 MAINTENANCE OBSERVATIONS (62703)

5.1 Emergency Diesel Generator Trips - Unit 2

On November 16, the Unit 2 Train B diesel generator experienced a non-emergency trip during an operability surveillance test. This trip was similar to the previous three trips that had recently occurred on this diesel

generator. During the last inspection period, a multi-discipline diesel generator task force team was established by management to determine the root cause of failure of the recent trips. The inspector documented this effort in Inspection Report 95-18.

The inspector observed troubleshooting efforts by the electrical technicians. The task force team leader developed an extensive four stage action plan to determine the cause of the trips, verify proper restoration of the diesel generator following maintenance activities, monitor diesel generator performance for spurious trips, and obtain additional data for assessment.

The diesel generator was returned to service on November 18, following maintenance activities and a satisfactory operability surveillance test. The inspector concluded that the task force team appeared thorough in their review and the troubleshooting efforts observed were adequate.

5.2 Charging Pump Power End Replacement - Unit 2

On November 21, the inspector observed some portions of the work that mechanical maintenance technicians were performing on the Train A charging pump. The technicians were replacing the power end of the pump. The inspector concluded that the work performed was adequate and well controlled.

In September, an auxiliary operator identified a low lube oil pressure condition on the Train A charging pump. The pump was declared inoperable and mechanical maintenance engineering was notified. The power end internals were inspected and found to have significant damage. The licensee initiated a CRDR and a formal root cause investigation.

The inspector attended meetings with the maintenance engineering staff to discuss the status of the investigation. The inspector noted that maintenance engineering had developed an extensive action plan to troubleshoot and investigate the cause of the power end internal damage.

The main contributor to the problem was an alignment problem that existed between the pump block and power end of the pump, as a result of maintenance performed several years ago. The shifted alignment was caused by defective power end studs and installation errors on this pump which do not appear to be applicable to the other pumps. Maintenance engineering management decided to replace the power end of the pump.

The inspector concluded that appropriate actions were taken by mechanical engineering. The investigation effort was extensive and thorough. The pump was placed in service and has since maintained oil pressure in the acceptable ranges.

5.3 Main Steam Safety Valve Response Following Reactor Trip - Unit 1

During the secondary plant pressure transient following the November 26 reactor trip (Section 2), three main steam safety valves (MSSVs) lifted. All

three safety valves were set to lift at 1250 psig ± 3 percent. Plant recorders indicated that the three valves lifted within tolerances and that pressures had not exceeded 1250 psig + 3 percent, indicating that the fourth valve, set at 1250 psig, could have remained seated and still been within setpoint tolerances.

Although two of the safety valves reseated within three minutes, MSSV 561 appeared to continue to modulate open and closed until pressure dropped below 1130 psig. Plant recorder data indicated that the reseat pressure would have been approximately 10 percent below the lift pressure. The licensee concluded that the blowdown could be expected to vary between three and nine percent. Additionally, they noted that the valve had been open for approximately 11 minutes when it reseated and considered that the heating of the valve could have lowered the reset pressure.

Following the reactor trip, operators allowed secondary pressure to increase (Section 2.1.5). MSSV 561 reopened at a pressure between 1155 psig and 1181 psig (5.5 to 7.6 percent below its setpoint). The valve was subsequently declared inoperable and gagged closed. While the unit was in Mode 3 and prior to restart, a licensee contractor, Furmanite, performed on-line testing using their Trevitest method. MSSV 561 was tested 11 times, with a total of five separate adjustments. The licensee ultimately was able to meet their criteria of three successive tests within one percent of 1250 psig.

The inspector reviewed the test results with the inservice testing engineering staff. They stated that MSSV 561 had initially lifted at 1197 psig. The inspector noted that this was considerably lower that its initial set pressure, as well as the pressure it appeared to lift at during the plant transient, considering that no adjustments had been made to the valve. The licensee could not explain the change in the setpoint.

After the first test lift, the valve nut was turned three flats of the nut. Although historical trends indicate that this adjustment should have raised the lift point approximately 30 psi, the next two tests were at 1194 and 1192 psig. The licensee could not explain why this had occurred, except that the safety valves do not respond consistently to nut adjustments. Subsequently, the valve appeared to lift at a consistent pressure after each adjustment.

The licensee noted that this safety valve had been placed in service in November, 1993 after having been refurbished. The inspector observed that in November, 1993 a similar valve in Unit 1 had lifted approximately 40 psi lower than its setpoint. As documented in LER 528/93-011, Revision 1, MSSV 572 was gagged closed for the remainder of the operating cycle when a review of test data had indicated that it had not responded consistently to adjustments made during testing. The inspector questioned how the performance of MSSV 561 was different than the November 1993 performance of MSSV 572. The licensee noted that MSSV 572 had behaved more erratically during testing than MSSV 561. The inspector reviewed documentation of the evaluation for MSSV 572 and concurred with this assessment.

5.4 Auxiliary Feedwater Pump Governor Valve Deficiencies - Unit 3

On November 23, the licensee entered Mode 3 following the refueling outage and began to perform testing on the turbine driven AFW pump. Technical Specifications require that the pump be tested within the first 12 hours of establishing normal operating temperature and pressure conditions. During the testing, the licensee observed that, after operating for extended periods, the governor had a tendency to lock up at speeds between 2000 and 3000 rpm.

The licensee developed an action plan and began investigating the problem. The troubleshooting and repair took over 70 hours of the 72 hours allowed outage time. The licensee ultimately discovered that the governor valve bonnet had been rotated approximately 1/4 inch, as indicated by match marks, when it was reinstalled during the refueling outage. This resulted in a misalignment of the linkage between the hydraulic servo and the governor stem, which caused the linkage to bind. The binding appeared to be enhanced as the turbine heated up and thermally shifted.

The licensee subsequently performed minor adjustments to the mounting of the hydraulic servo and the linkage to align them with the rotation of the governor valve bonnet. They performed subsequent testing which demonstrated that the linkage operated smoothly. In addition, in the following week, the licensee tested the Units 1 and 2 turbine driven AFW pumps to ensure that similar binding was not occurring.

The inspector observed portions of the troubleshooting and repairs and determined that they were well controlled. The inspector discussed the troubleshooting effort with maintenance management. They had determined during the troubleshooting that there was additional data which could be gathered during the setup of the governor valve which would aid in future maintenance and troubleshooting efforts. This included establishing a baseline of the electronic signal into the governor module and the hydraulic pressure output as speed demands are changed. In addition, maintenance management stated that they planned to address the misalignment of the governor valve bonnet as a maintenance performance error and initiate corresponding corrective actions.

5.5 Essential Chiller Problems - Units 1 and 3

During the inspection period, the inspector observed portions of troubleshooting efforts by the heating, ventilation and air conditioning (HVAC) team to resolve problems experienced by the Unit 1 Train B essential chiller and the Unit 3 Train A essential chiller. The HVAC team was comprised of representatives from design engineering, system engineering, maintenance engineering, and the maintenance staff.

The essential chilled water system supplies chilled water to the essential air cooling units and air handling units in the Control Building and the Auxiliary Building during essential equipment operation. The essential chiller system consists of two separate, redundant, safety-related flow trains. The

essential chiller system starts automatically when essential equipment operation is required.

5.5.1 Essential Chiller Trip - Unit 1

On November 27, the Unit 1 operators were recovering from a reactor trip (Section 2) and had started the Train B essential chiller to support room cooling to the Train B auxiliary feedwater pump. Approximately 30 minutes into the run, the chiller tripped due to low refrigerant temperature. Operators complied with Technical Specification action statements, initiated a CRDR, and contacted HVAC personnel.

The HVAC team initiated an evaluation of the chiller trip. The system engineer stated that the "low refrigerant temperature" trip appeared to have been caused by a low refrigerant level in the cooler. The cooler is a shell and tube heat exchanger. Low pressure, liquid refrigerant on the shell side absorbs heat from chilled water flowing through the tubes as the refrigerant flashes to vapor. The refrigerant level prior to the trip was approximately 3.5 inches.

The HVAC technicians identified some minor freon leaks and restored the refrigerant level to approximately 6 inches. The chiller was tested and returned to service. The leaks were subsequently repaired during an on-line outage of the chiller.

The inspector discussed the chiller trip with the system engineer. The system engineer stated that during cold weather conditions the refrigerant experiences a "stacking" phenomena. During normal operation, vapor refrigerant should condense to a liquid in the condenser and flow to the cooler. However, when essential cooling water, which flows through the condenser, is colder, a low pressure condition exists which causes the liquid refrigerant to stay in the condenser. It appeared that a high level of refrigerant in the cooler was necessary to ensure that the stacking phenomenon would not result in a chiller trip.

The inspector discussed the issue of refrigerant level with the system engineer. It appeared that there was competing guidance on the appropriate levels of refrigerant in the chillers.

- Engineering evaluation request (EER) 88-EC-003, determined the recommended refrigerant levels required during shutdown conditions. The Unit 1 Train B essential chiller refrigerant levels were 4.88 inches minimum and 6.0 inches maximum.

- EER 90-EC-031, which apparently superseded EER 88-EC-003, specified a shutdown refrigerant level band for each chiller of 3.0 inches minimum and 7.0 inches maximum. This level band was incorporated in the weekly preventive maintenance task.

- During the Unit 1 fifth refueling outage, HVAC technicians identified pitting on the compressor first stage impeller. Design engineering speculated that the pitting was caused by liquid refrigerant carryover. The compressor is a two-stage, centrifugal type. It takes suction on the cooler shell, increases the refrigerant gas pressure, and discharges the refrigerant gas to the chiller condenser. The design engineer recommended that refrigerant levels be maintained in the lower region of the level band to prevent impeller damage by liquid refrigerant carryover.

- During discussions with the system engineer on December 21, the engineer could not conclude that a chiller could be considered operable with a level of 3.5 inches.

- On December 21, the inspector identified that one of the chillers in Unit 3 had a level of about 3/8 of an inch above the 7 inch maximum. This level did not appear to be consistent with any of the guidance provided. The inspector noted that the weekly preventative maintenance task still specified a level from 3 inches to 7 inches. The licensee immediately lowered the level to 6 inches and initiated a CRDR to document and resolve the problem.

The inspector concluded that the licensee did not have a good understanding of the appropriate levels for the chillers and had not implemented sufficient measures to assure that chiller refrigerant levels were properly maintained.

5.5.2 Train A Essential Chiller Low Lube Oil - Unit 3

On October 2, the Unit 3 Train A essential chiller was removed from service for a maintenance outage. During this outage, the rear motor bearing seal to the compressor was inspected and the O-ring seals were replaced. The technicians had problems with the replacement of the rear seal and the O-ring had to be replaced again.

The compressor and motor are refrigerant cooled and oil lubricated. A motor driven, compressor lubricating oil pump and reservoir are located in the compressor base. There are two sight glasses, an upper and lower bulls-eye, that represent the minimum and maximum oil levels. The licensee has established that the chiller should not be operated with the oil level below the lower sightglass, which corresponds to approximately 7.5 gallons of oil, or with an oil level in excess of 25 gallons.

On October 29, the chiller was returned to service following the maintenance outage with an initial volume of 15 gallons of oil. On November 27, the Train A essential chiller was declared inoperable after an AO noted that the oil pump appeared to be cavitating due to low reservoir level. HVAC technicians added more oil and retested the chiller. The chiller was then returned to service.

The licensee subsequently determined that from November 10, through November 27, 17 gallons of oil had been added to the system to maintain the minimum oil level requirements. Operations initiated a CRDR and the HVAC personnel developed an action plan to resolve the apparent loss of oil.

The HVAC system engineer explained to the inspector that during cold weather conditions the oil tends to migrate with the refrigerant. Once the chiller is operated under loaded conditions, the oil will heat up and return back to the oil sump. The guidance given to operations by the HVAC engineer was to have an operator present during any start of the essential chiller. Since there was a total of 32 gallons of oil in the system, once the chiller is fully loaded the oil would migrate back through the oil return system and the operator would need to drain the oil. If the reservoir becomes too full of oil, a "high bearing temperature trip" could result.

On December 5, the inspector observed HVAC technicians perform maintenance activities on the Train A essential chiller. The oil was removed from the system. The technicians removed and replaced the rear motor bearing seal. The technician added 12 gallons of oil and the chiller was tested. After a successful four hour run, the chiller was returned to service. The repairs appeared to have addressed the oil migration problem.

The inspector was concerned that the repair performed during the refueling outage may have caused the oil migration problem. Additionally, the inspector was concerned that the licensee had not established an appropriate basis for considering the chiller operable after it was identified on November 27 to have excessive oil.

5.5.3 Summary

The licensee initiated CRDRs to address both the Units 1 and 3 problems. Additionally, the Executive Vice President initiated a Level 1 action item to resolve these issues. The licensee initiated measures to determine the refrigerant level required to assure chiller operability and resolve the inconsistent guidance. The inspector considered this to be an Unresolved Item (528/9521-01).

6 SURVEILLANCE OBSERVATION (61726)

6.1 Containment Spray Pump Testing - Unit 3

On November 5, while Unit 3 was in an outage, operations personnel performed surveillance test 73ST-9SI15, "Containment Spray Pump Full Flow Inservice Test," on the Unit 3 Train A containment spray (CS) pump. The CS pump failed both the ASME Code Section XI and design basis full flow tests. The licensee checked the test instrumentation and, although they were able to demonstrate some improvement, the pump again failed its design basis flow test. The licensee disassembled the pump and was unable to identify significant degradation or wear. Mechanical maintenance technicians replaced the impeller with another impeller to improve performance. The licensee performed a

Section XI test to establish the new pump curve and found that the pump had improved performance.

The inspector observed portions of the corrective maintenance and surveillance testing, reviewed inservice testing procedures and performance history, and discussed the cause of the apparent degradation with inservice testing engineers, maintenance engineers, and system engineers.

6.1.1 Testing Methodology

The licensee performed several inservice tests of the CS pumps. The two Section XI tests, a monthly test performed on mini-flow recirculation and a refueling outage test at 3525 gpm, were to verify that the pump performed to its baseline pump curve. A design basis flow test to establish that the pump could develop a minimum differential pressure at 4000 gpm was added in 1994 and was being performed on the Train A CS pump for the first time. The acceptance criteria for the full flow Section XI test, at 3525 gpm, was differential pressure between 219 psid and 233.6 psid. The acceptance criteria for the design basis test, at 4000 gpm, was a differential pressure of greater than 211 psid. The Section XI November 5 test result was 217.3 psid and the design basis test result was 198.3 psid.

During their investigation, the licensee identified that the correction factor used in both tests to compensate for instrument gauge location was incorrect. The correction factor used in the surveillance test procedure was 1.3 psid. This correction factor failed to properly compensate for gauge elevation differences and the pressure drop across a flow orifice between the pump discharge and the discharge pressure gauge. The licensee determined that the correction factor should have been 11.7 psid for the Section XI test and 12.1 psid for the design basis test.

With the new correction factor the Train A CS pump would have passed its Section XI test with a differential pressure of 227.7 psid, but would not have passed the design basis flow test, which was being performed for the first time.

6.1.2 Correction Factors for Section XI Tests

The licensee was unable to determine the basis for the 1.3 psid correction factor used in the Train A CS pump full flow tests. They did discover that the correction factor used in the mini-flow recirculation test was correct. They found that the correction factor for the full flow tests had been established in 1989 when full flow testing was initiated. The error in the correction factor had not been identified when the procedure was revised in 1994 to add the design basis flow test.

The licensee subsequently reviewed all other CS pump tests and found similar errors in the full flow test correction factors. However, the licensee determined that these differences had not impacted the conclusions of these

tests. Additionally, the licensee found minor discrepancies with the correction factors of other Section XI tests.

At the end of the inspection period, the licensee was establishing the basis for the correction factors used in all Section XI tests with the intent of maintaining the basis. The inspector found these actions to be appropriate.

6.1.3 Motor Replacement

In 1987, the licensee replaced the Train A CS pump motor with a motor having a lower nameplate speed (1757 versus 1779 rpm). The licensee did not rebaseline the CS pump curve with the new motor. This change would have had a greater effect on the pump at higher loads. The licensee stated that the design basis full flow test loaded the motor to two-thirds of its capacity and would not have had a significant impact on the pump curve.

The inspector discussed some uncertainties that may exist with the system engineer concerning the design basis surveillance test. He stated that in addition to using the appropriate correction factor, if additional uncertainties were removed, for example, taking credit for the miniflow valve that does not come full open and using a more accurate flow instrument, it would be expected that the CS pump would have marginally passed its design basis full flow test.

6.1.4 Conclusions

10 CFR 50, Appendix B, Criterion V requires that procedures shall include appropriate acceptance criteria. The CS full flow test procedure did not have appropriate acceptance criteria in that the instrument correction factors used to determine differential pressures were in error and this constituted a violation of more than minor safety significance. The inspector reviewed the licensee evaluation, discussed the corrective actions with management, and concluded that the corrective actions were appropriate. Additionally, the inspector noted that the problem was identified by the licensee and that there were no similar violations identified by either the inspectors or by the licensee which could have reasonably prevented this occurrence. This licensee identified and corrected violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy.

7 ONSITE ENGINEERING (37551)

7.1 Steam Generator Modifications - Unit 3

The licensee performed modifications to the Unit 3 steam generators during the refueling outage to reduce the dryout region in the upper portion of the tube bundle. The modifications included extending and lowering the elevation of the downcomer feedring, removing orifices in the moisture separators on the hotleg side, and cutting 45 three inch diameter holes in the shroud between the downcomer and the tube bundle.

Due to unanticipated problems associated with the modification:

- The licensee cut only 27 holes in one steam generator shroud and no holes in the other generator due to problems experienced with the cutting tool.

- The licensee discovered that a cyclic low energy water hammer developed in the new downcomer feedring when low steam generator levels and AFW flow below 200 gpm were established.

- Operators noted that the feedwater level control system developed oscillations of approximately 10 percent level peak to peak with reactor power between 25 and 45 percent.

7.1.1 Steam Generator Shroud Holes

The licensee attempted to cut 45 holes in the shroud between the downcomer and the tube bundle using a three inch diameter electrical discharge machining (EDM) tool. The job was performed remotely by lowering the EDM tool on the downcomer side of the shroud. Each cut was expected to take up to 11 hours to perform.

The licensee found that each cut was taking substantially longer than expected to perform. In addition, the EDM tools, which were expected to last for up to three holes were eroding after one hole and in one instance an EDM tool head fell off the EDM tool into the area between the shroud and the tube bundle. The majority of the head was retrieved and a safety evaluation was performed for the remainder which concluded that it could not damage the steam generator.

The licensee had previously mocked up the modification process at a vendor's facility. They determined that the conductivity of the water in the steam generator was greater than the conductivity at the mock up facility and that this difference had contributed to the problems in the rate of cutting and the life of the EDM tool. The licensee was evaluating the cause of the differences in conductivity.

The licensee completed only 27 holes in steam generator 32 and elected not to cut holes in steam generator 31. They revised the 10 CFR 50.59 evaluation to disposition this interim condition. The inspector reviewed the evaluation and noted no discrepancies. The licensee concluded that the condition was bounded by the evaluations performed for the original design and for the completion of the entire modification. Additional calculations were performed by the vendor to address flow velocities at the tube bundle and found that the new flow velocities would be acceptable.

7.1.2 Feedring Water Hammer

After the licensee had entered Mode 3, they lowered level in one steam generator as part of a chemistry control evolution. Engineers working on the turbine driven AFW pump noted a cyclic banging in the AFW discharge lines. Engineers subsequently determined that the water hammer condition had been established in the modified feed ring under certain flow conditions.

The downcomer feed line rises up the outside of the steam generator to the nozzle. On the inside of the generator there is a slip fit between the nozzle and the feedring. The line has a 90 degree bend as it turns downward and tees into the lines that form the feed ring. The licensee determined that with no flow to the downcomer line, a 40 inch section at the nozzle dries out. At low flow conditions, this portion did not completely fill. As a result, the vapor in this space would condense in the environment of the cold AFW water causing the water hammer.

The inspector observed the licensee evaluate the problem and establish a special test to determine the conditions where the water hammer developed. In addition, the inspector observed portions of the testing. The inspector noted that although the testing was performed over a holiday weekend, appropriate levels of licensee management were involved. The testing determined that the water hammer was occurring with steam generator levels below 25 percent of the narrow range instruments and at flows less than 200 gpm. Additionally, they monitored pipe movement, installed an accelerometer, and inspected the insulation around pipe hangers and determined that there was no discernable movement in the piping. Based on these observations, they concluded that the water hammer was of low energy and would not damage the steam generators.

The licensee initiated a CRDR and planned to take action to revise operating instructions to restrict AFW flows to above 200 gpm when below 25 percent SG level.

7.1.3 Flow Oscillations At Low Reactor Power

During reactor startup, with reactor power between 25 and 45 percent, feedwater flow oscillations would cause steam generator level swings of up to 10 percent peak to peak. Engineers obtained data to evaluate the cause of the oscillations and to establish if changes to the FWCS could be made to reduce the oscillations. The licensee also provided guidance to operators on actions to take in this region if power is reduced.

7.2 <u>Potential Loss of Two AFW Pumps Following a Steam Line Break</u>

On December 1, the licensee made a four hour non-emergency report to the NRC in accordance with the requirements of 10 CFR 50.72 for a condition outside of their design basis. The licensee had identified that, following a steam line break of a specific size and a loss of offsite power, a sequence of events could occur with design basis assumptions that could lead to the turbine driven AFW pump tripping on overspeed. The licensee postulated that with the coincident single failure of the motor driven AFW pump and with no credit for

operator actions within the first 30 minutes of the event, that emergency feedwater would be lost to the intact steam generator.

The licensee planned to describe the details of the event in Licensee Event Report 50-528/95-013. The inspector had discussed the potential for this sequence of events with the licensee in Inspection Report 95-12. At the time, the licensee had not determined if there was a break size that could lead to the event.

The licensee has noted that the sequence of events did not consider operator action and assumed some conservative initial conditions outside of normal operating parameters. The inspector reviewed the initial conditions and operating procedures and found that they provided reasonable assurance that emergency auxiliary feedwater would be available following a steam line break. This is an Unresolved Item (528/9521-02).

8 FOLLOWUP - OPERATIONS (92901)

8.1 Unresolved Item 528/9514-02 (Closed): Two Auxiliary Feedwater Pumps Inoperable

This unresolved item involved the failure of Unit 1 operators to recognize that one auxiliary feedwater pump was already inoperable when they prepared to remove a second auxiliary feedwater pump from service to perform a breaker modification. Technical Specification 3.7.1.2 required that, with two auxiliary feedwater pumps inoperable, the unit be in hot standby within six hours. Both AFW pumps were inoperable for approximately 5.5 hours.

On August 9 at 6:00 a.m., the night shift removed the Train A spray pond from service prior to shift change. Operators entered the action statement for Technical Specification 3.7.1.2 for the Train A AFW pump (the turbine driven pump) since without the spray pond, the essential ventilation for the Train A was inoperable. Around 9:15 a.m. the day shift crew removed the Train N AFW pump to perform a modification on its breaker. They did not recognize that this placed them in the six hour action statement. At approximately 3:00 p.m., operators racked in the breaker for the Train A spray pond which subsequently tested satisfactorily.

Operators on the subsequent night shift recognized that the day shift had removed both AFW pumps from service. They returned the Train N AFW pump to service at around 8:00 p.m. and initiated a CRDR. The licensee designated the CRDR as significant and established an investigation team to review the event. The licensee subsequently determined that they had met the Technical Specification requirement in that they had established operability within the six hours allowed.

The inspector reviewed the licensee's investigation. The inspector concurred that the licensee had not exceeded the six hour shutdown requirement. The inspector noted that the investigation had identified that the work on both the Train A spray pond and the Train N AFW pump were pre-planned for the same

day. While the work on the Train A spray pond was reviewed as a significant job, the Train N AFW pump had not been considered significant work. The investigation focused on the work control process weaknesses which had resulted in this oversight. The inspector reviewed this evaluation and the proposed corrective actions and found them to be thorough.

The licensee also noted that a contributor to the scheduling problem was the inappropriate application of the recently implemented probabilistic risk assessment matrix. The matrix provided risk insights to operators for emergent work. The matrix established that combinations of equipment which place the plant in Technical Specification 3.0.3 are not allowed regardless of the risk significance. However, the matrix did allow the more restrictive Technical Specification requirement for two AFW trains inoperable, in that it suggested that removing the Train N AFW with the Train A spray pond had provided no additional risk. The control room supervisor had referred to the matrix prior to removing the Train N AFW pump from service. One of the corrective actions was to reinforce with operators that the matrix was a tool to be used in conjunction with Technical Specifications and did not include all restrictions. The inspector found this to be appropriate.

The inspector noted that ultimately it was the operating crews responsibility to recognize that removing the Train N AFW pump from service was not appropriate. The licensee's investigation identified that the control room supervisor, who had authorized the work, had not discussed the decision with either the shift supervisor or the shift technical advisor. When he subsequently discussed it with the shift supervisor, the shift supervisor had not recognized that two trains of AFW were inoperable.

Additionally, the shift technical advisor was responsible for maintaining the technical specification component condition record log to track equipment out of service. The procedure governing this log required that equipment that is out of service through a shift change be logged. While the Train N AFW pump was not expected to be out of service through the shift change, it ultimately was. The inspector considered that this was a failure to follow procedure. The Operations Department Leader discussed this weakness and the expectations on communications with all licensed operators during the subsequent training cycle. The licensee also counselled members of the crew involved.

The inspector considered that the failure of operators to follow procedure 40DP-90P23, "Technical Specification Component Condition Record Sims Procedure," and log the Train N AFW pump to be a violation of Technical Specification 6.8.1 of more than minor safety significance. The inspector found that the licensee's actions were appropriate. Additionally, the inspector noted that the problem was identified by the licensee and that there were no similar violations identified by either the inspectors or by the licensee which could have reasonably prevented this occurrence. This licensee identified and corrected violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy.

9 FOLLOWUP - ENGINEERING/TECHNICAL SUPPORT (92903)

9.1 Unresolved Item 528/9431-01 (OPEN): Letdown Isolation Valve Leakage

On December 8, the licensee closed Unit 2 letdown isolation valve CHA-516 and determined that it did not leak with approximately 2000 psi differential pressure across it. This test supported the licensee's analysis which concluded that the three letdown isolation valves in Unit 2 could close against pressures established during a letdown line break and prevent downstream flow from exceeding calculated limits. The letdown isolation valve operators in Units 1 and 3 were replaced during the past refueling outages to resolve the concern that they were undersized.

Earlier in the inspection period, the licensee identified that, in April 1995, the as-found condition of Unit 1 letdown isolation valve CHB-515 had not been accurately described to engineers performing an operability determination. Upon recognizing the flawed Unit 1 operability determination, the licensee reperformed the operability determination and developed a reasonable assurance that the Unit 2 valves were operable. Subsequently, they determined that an online test would establish conclusively that all three Unit 2 valves were operable. The inspector concluded that the decision to perform the test demonstrated conservative engineering and found that the licensee had performed substantial reviews and exercised proper caution in performing the test.

The inspector noted that the failure to properly characterize the as-found condition of Unit 1 CHB-515 was another example of weak engineering.

10 ONSITE REVIEW OF LERs (92700)

10.1 (Closed) LER 528, 529, 530/93-011, Revision 1: Potential Safety-Related Equipment Problems Due to Degraded Grid Voltage and (Closed) LER 528/95-001, Revision 0: Entry Into TS 3.0.3 Due to Degraded Voltage

10.1.1 Licensee Reports

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

The licensee stated if grid voltage were kept above an administrative limit, their calculations indicated that the double sequencing would not occur. The licensee also discussed long term corrective actions and stated that pending completion of these actions the grid would be kept above 100 percent.

However, on February 15, 1995, the licensee entered Technical Specification 3.0.3, due to grid voltage falling below 100 percent during planned switchyard evolutions. The licensee issued LER 95-001, Revision 0, on March 15, 1995, to report the February 15, 1995, occurrence.

10.1.2 Licensee Actions

The licensee issued a new procedure specifying operator actions in response to a degraded grid and added degraded grid voltage to the Unit 1 Plant Monitoring System displays. The licensee stated that the following long term corrective actions would make all three units operable above 98 percent grid voltage, the design lower limit.

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

10.1.3 Summary of Inspector Actions During Inspection Report 95-12

The inspector reviewed both LERs, the licensee's procedure for response to degraded grid voltage, the licensee's review of the potential for further occurrences of degraded grid voltage, the licensee's long term corrective actions, and the requirements the licensee provided to grid operators.

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

The inspector reviewed licensee Letter File 95-005-419.8, "PVNGS Expectations Regarding Evaluations Potentially Affecting Grid Voltage Range Limits," dated February 23, 1995, and noted that grid operational expectations were clearly stated.

The inspector noted that the licensee had used the site main generators to raise grid voltage during the February 15 event and questioned the licensee as to whether grid operators could have raised this voltage external to the site on February 15, or during future occurrences when there was no site generation. The licensee provided the inspector a grid study titled, "PVNGS

525 Kv Voltage Regulation Study Report." This report concluded that the grid could reliably be maintained above 98 percent, without site generation support.

10.1.4 Inspector Actions During This Inspection and Conclusions

The inspector reviewed licensee progress on the long term corrective actions and determined that the licensee was still within their internal schedule for completion of these actions. The inspector questioned control room personnel in Unit 1 and determined that they were familiar with offsite power requirements and procedure 41AO-1ZZ57. The inspector reviewed updated licensee calculations. Based on this review and the more detailed review described in Inspection Report 50-528/95-12, the inspector concluded that the licensee had taken corrective actions to identify when a low voltage condition existed on the grid, and specified proper actions to take to ensure that Palo Verde units remained operable and complied with Technical Specification shutdown criteria. The inspector also noted that the licensee had provided reasonable assurance of their intent to complete the long term corrective actions discussed above.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Arizona Public Service Company

*T. Cannon, Department Leader, Nuclear Engineering and Projects
B. Chapin, Department Leader, Mechanical Maintenance
*R. Flood, Department Leader, System Engineering
*R. Fullmer, Department Leader, Nuclear Assurance
*B. Grabo, Section Leader, Nuclear Regulatory Affairs
*R. Hazelwood, Engineer, Nuclear Regulatory Affairs
*W. Ide, Director, Operations
*A. Krainik, Department Leader, Nuclear Regulatory Affairs
J. Levine, Vice President, Nuclear Production
*D. Mauldin, Director, Maintenance
*W. Montefour, Senior Representative, Strategic Communications
*G. Overbeck, Vice President, Nuclear Support
*C. Seaman, Director, Nuclear Assurance
*J. Vellota, Director, Training
M. Winsor, Section Leader, Mechanical Maintenance Engineering

1.2 NRC Personnel

*D. Kirsch, Chief, Region IV Reactor Projects Branch F
*K. Johnston, Senior Resident Inspector
*D. Garcia, Resident Inspector
*J. Kramer, Resident Inspector

1.3 Others

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

*Denotes those present at the exit interview meeting held on December 20, 1995.

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

2 EXIT MEETING

An exit meeting was conducted on December 20, 1995. During this meeting, the inspectors summarized the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

LIST OF ACRONYMS

ADV	Atmospheric Dump Valves
AFW	Auxiliary Feedwater
AO	Auxiliary Operator
CRDR	Condition Report/Disposition Request
CS	Containment Spray
EDM	Electrical Discharge Machining
EER	Engineering Evaluation Request
ERFDADS	Emergency Response Facility Data Acquisition Display System
FWCS	Feedwater Control System
gpm	Gallons Per Minute
HLO	High Level Over-ride
HVAC	Heating, Ventilation and Air Conditioning
LER	Licensee Event Report
MSSV	Main Steam Safety Valve
NPSH	Net Positive Suction Head
RCS	Reactor Coolant System
RWLIS	Refueling Water Level Indicating System
SBCS	Steam Bypass Control System
SG	Steam Generator