UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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May 4, 2004

Gregg R. Overbeck, Senior Vice
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Arizona Public Service Company
P.O. Box 52034
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SUBJECT: PALO VERDE NUCLEAR GENERATING STATION, UNIT 2 - NRC SPECIAL INSPECTION REPORT 05000529/2004-009

Dear Mr. Overbeck:

On February 25 through March 3, 2004, the U.S. Nuclear Regulatory Commission (NRC) conducted a special inspection at your Palo Verde Nuclear Generating Station, Unit 2. The purpose of the inspection was to evaluate the impact of an extended period of reduced reactor coolant inventory operation, gas entrainment in the shutdown cooling system, and the primary-to-secondary leakage that caused the need to enter a reduced inventory condition. The inspection effort continued with in-office reviews through April 8, 2004. The enclosed report documents the inspection findings, which were discussed on April 8, 2004, with members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The team reviewed selected procedures and records, observed activities, and interviewed engineers, operators, maintenance personnel, and management representatives.

Overall, the team determined that licensee operated the plant safely during the period of concern. Based on the results of this inspection, the NRC identified two findings that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC also determined that there was a violation associated with each of the findings. These violations are being treated as noncited violations, consistent with Section VI.A of the Enforcement Policy. These noncited violations are described in the subject inspection report. In addition, the NRC identified an apparent violation of Criterion XVI, *Corrective Action*, of Appendix B to 10 CFR Part 50, for failure to promptly identify that steam generator retaining ring slots were inadequately sized for use of standard nozzle dam locking pins. This apparent violation is unresolved because risk significance has not yet been determined. If you contest the violations or significance of the noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Palo Verde Nuclear Generating Station facility.

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Sincerely,

/RA/

Dwight D. Chamberlain, Director
Division of Reactor Safety

Docket: 50-529
License: NPF-51

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Inspection Report 05000529/2004-09

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-529
License:	NPF-51
Report No.:	05000529/2004-009
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	February 25 through March 3, 2004, with In-Office inspection through April 8, 2004
Team Leader:	C. Paulk, Senior Reactor Inspector, Engineering Branch
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Approved By:	C. S. Marschall, Chief Engineering Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000-529/2004009; February 25 through April 8, 2004; Palo Verde Nuclear Generating Station, Unit 2: Special Inspection to evaluate extended period of reduced inventory operation with gas entrainment in the shutdown cooling system and the primary-to-secondary leakage, which resulted in the need to enter reduced inventory.

The report covered an 8-day period (February 25 through March 3) of inspection onsite, with in-office review through April 8, by a special inspection team consisting of two region-based inspectors, one resident inspector, and one senior level specialist from the Office of Nuclear Reactor Regulation. Two noncited violations and an apparent violation were identified. The significance of most findings is indicated by its color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

NRC-Identified and Self Revealing Findings

Cornerstone: Mitigating Systems

- Green. A noncited violation of Technical Specification 5.4.1a. was identified for the failure to correctly implement the venting requirements of Procedure 40OP-9SI01, Appendix D. Specifically, when venting the shutdown cooling system while in reduced inventory, the operators failed to attain a steady stream of air free water from Valve V019 and vented from a location not specified in the procedure.

  This finding was more than minor because the failure to properly vent the shutdown cooling system while in reduced inventory could, if left uncorrected, become a more significant safety concern. The inadequate venting was associated with the operability, availability, and function of the shutdown cooling system while in reduced inventory (i.e., potential loss of long term decay heat removal).

  This performance issue was found to be of very low safety significance (GREEN), because none of the plant conditions met the threshold for performing a Phase 2 analysis. This finding has cross-cutting implications in the human performance area. That is, this violation was the direct result of operators not correctly implementing a procedure.

  The licensee entered this issue into its corrective action program as Condition Report/Discrepancy Request 2686273 (Section 3.1).

- TBD. A violation of Criterion XVI, *Corrective Action,* of Appendix B to 10 CFR Part 50, was identified for the failure of the measures established to assure that conditions adverse to quality are promptly identified and corrected. Specifically, licensee personnel failed to promptly identify that retaining ring slots were not adequately sized to allow the use of the standard lock pins, contributing to the damage to the diaphragms. Subsequent to the identification, licensee personnel failed to correct the condition by not implementing the actions recommended by plant engineers.

This finding was more than minor because it is associated with the mitigating systems cornerstone and affects reactor coolant system boundary performance. Specifically, the plant operated for an extended period in reduced inventory as a result of not correcting the incompatibility between the nozzle dams and the locking ring. This finding has cross-cutting implications in the problem identification and resolution area. That is, this finding was the direct result of licensee personnel's failure to promptly identify and correct a condition adverse to quality. The licensee entered this issue into its corrective action program as Condition Report/Discrepancy Requests 2686201 and 2686271. This apparent violation is unresolved because the significance of this finding is to be determined (Section 3.4).

Cornerstone: Barrier Integrity

- Green. A noncited violation of Criterion XVI, *Corrective Action,* of Appendix B to 10 CFR Part 50, was identified for the failure of the measures established to assure conditions adverse to quality are promptly identified and corrected. Specifically, although a fabricator informed licensee representatives of a tube with damage from a packing crate screw, the licensee representative did not enter the issue into the corrective action program to assure that the adverse condition (i.e., inadequate packing of tubes) was promptly corrected. Additionally, the corrective action program was deficient in that there was no mechanism to ensure that adverse conditions identified by the fabricator were made known to the appropriate licensee personnel. As a result, the potential for a similarly damaged tube to exist in the steam generators installed in the plant was not assessed, nor were actions taken to support detecting such a damaged tube during the pre-service examination by the licensee's eddy current examiners.

  This finding is more than minor because it had actual safety consequences (i.e., a steam generator tube leak). This finding affects the barrier integrity cornerstone because of the potential to release radionuclides through the leaking tube. Reactor coolant system barrier performance was the affected attribute. This finding has cross-cutting implications in the problem identification and resolution area. That is, this finding was the direct result of the engineering staff's failure to properly address and correct a condition adverse to quality. The licensee entered this issue into its corrective action program as Condition Report/Discrepancy Request 2685303 (Section 4.1).

  This finding was found to be of very low safety significance after a Phase 3 evaluation using the Manual Chapter 0609, *Significance Determination Process*.

REPORT DETAILS

SPECIAL INSPECTION ACTIVITIES

1 Inspection Scope

The team conducted a special inspection to evaluate the impact of the Palo Verde Nuclear Generating Station, Unit 2, extended period of reduced reactor coolant inventory operation, gas entrainment in the shutdown cooling system and the primary-to-secondary leakage that resulted in the need to enter reduced inventory. The primary-to-secondary leakage was identified on February 19, 2004, at approximately 3:45 p.m. MST, with licensee management deciding to shut the plant down approximately 2 hours later.

The team used NRC Inspection Procedure 93812, *Special Inspection Procedure*, to perform the scope identified in the inspection charter, dated February 27, 2004. The charter may be found on the NRC's document system (ADAMS) under Accession No. ML040580698. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Reading Room).

2 Sequence of Events

Note: An overview of the sequence of events is provided here. Refer to Attachment 2 for more detail.

On February 19, 2004, Palo Verde Nuclear Generating Station, Unit 2, was at 100 percent reactor power. At 7 a.m. MST, the operations director questioned the indicated primary-to-secondary leak rate (based on Xe-135 concentration), which had increased to 0.75 gallons per day (gpd). At 3:22 p.m. MST, the operators received unexpected alarms on Monitor RU-142 Channels 1 and 2, *Main Steam Line –16 Gamma Radiation Monitor*, and began monitoring reactor coolant system parameters for indications of reactor coolant system leakage and notified their effluents department. At 4 p.m. MST, operations management determined that a unit shutdown was required due to an evaluation by the effluents department that an approximately 11 gpd primary-to-secondary leak was in progress in Steam Generator 21. The operators commenced preparations for shutdown of Unit 2 with assistance from reactor engineering.

At 4:50 p.m. MST, effluent department technicians reported that samples taken from the condenser air removal pump discharge at 4 p.m. MST provided the following results for primary-to-secondary leakage: 2.3 gpd (based on Xe-135 concentration) and 5.2 gpd (based on Xe-133 concentration). At 6:23 p.m. MST, control room operators manually tripped the reactor from 21 percent rated thermal power and entered Mode 4 at 10:48 p.m. MST. On February 20, at 5:25 a.m. MST, operations personnel placed shutdown cooling in service via low pressure Safety Injection Pump B. The reactor entered Mode 5 condition at 5:46 a.m. MST.

On February 23 at 2 a.m. MST, operators commenced a drain of the reactor coolant system to the refueling water tank from an initial value of 55 percent indicated pressurizer level. At 11:57 a.m. MST, reactor coolant system level was at less than

111 feet and the unit entered reduced inventory conditions. At 9:40 p.m. MST, the reactor vessel level was less than 103 feet 1 inch and the unit entered midloop conditions. On February 24, at 12:27 a.m. MST, the operators secured the reactor coolant system draindown and stabilized reactor vessel level at 101 feet 9 inches.

At 12:39 a.m. MST, maintenance personnel removed hot- and cold-leg manways from both steam generators and commenced installation of both cold-leg nozzle dams at 5:11 a.m. MST. At 5:53 a.m. MST, cold-leg nozzle dams were installed and pressurized and installation of hot-leg nozzle dams began.

At 5:30 p.m. MST (approximately 19 hours after entering midloop conditions), operations personnel vented the Train B containment spray pump suction at Valve SIB-V019. At ½-turn open, constant gas vented for 7 minutes. At ¼-turn open, an air/water mixture issued for 34 minutes before a solid stream of water flowed from the vent.

At 10:02 p.m. MST, maintenance personnel removed the hot-leg nozzle dam on Steam Generator 22. As of 11:38 p.m. MST, the newly installed nozzle dam on Steam Generator 22 hot-leg would not hold air pressure within the dry seal.

Over the next 12 hours, repeated venting operations were performed on the operating shutdown cooling train (i.e., B Train of low pressure safety injection). During each venting operation, some amount of gas (varying from 30 to 90 seconds) and some amount of gas/water mixture (varying from 15 to 30 minutes) issued from the vent. On February 25, at 1:38 p.m. MST, the hot- and cold-leg nozzle dams were removed on Steam Generator 22 as licensee management personnel decided to exit midloop conditions before correcting the aforementioned problems.

At 4:35 p.m. MST, Steam Generator 22 manways were installed. At 4:56 p.m. MST, operations personnel commenced the fill of the reactor coolant system from an indicated level of 101 feet 9.25 inches to a target of 118 feet using two charging pumps. At 5:55 p.m. MST, reactor vessel level was at greater than 103 feet 1 inch and Unit 2 exited midloop conditions.

At 8:38 p.m. MST, the operators completed the last vent of Train B shutdown cooling with gas free results. At 1:01 a.m. MST, February 26, reactor vessel level had been increased to 118 feet and the operators exited reduced inventory condition.

3 Gas Entrainment in Shutdown Cooling System

3.1 Response to Gas Entrainment

a. Scope

In accordance with the inspection charter, the team reviewed the licensee's response to the gas entrainment in the shutdown cooling system during extended operations in a reduced inventory condition.

b. Observations and Findings

Introduction. The team identified a noncited violation of very low safety significance for failure to implement a procedure.

Description. On February 19, 2003, a primary-to-secondary leak developed in Steam Generator 22. Operations personnel shutdown the reactor the same day, and placed shutdown cooling in service on February 20. During the time period that the plant was in reduced inventory, all safety-related equipment required for mitigating an analyzed event (with the exception of the steam generators) was operable and available. Additionally, while the steam generator manways were open, only one valve would have been required to be opened to provide a gravity feed from the refueling water storage tank to the reactor vessel.

On February 23, at 9:40 p.m. MST, operations personnel lowered reactor vessel to midloop conditions in support of nozzle dam installations for Steam Generator 21 troubleshooting and repairs. Approximately 20 hours later, at 5:30 p.m. MST, on February 24, operations personnel performed the first vent of the operating shutdown cooling train after reaching reduced inventory.

Appendix D, *Periodic Venting of the SDC Header*, of Procedure 40OP-9SI01, *Shutdown Cooling Initiation*, Revision 30, contains directions for periodic venting of the shutdown cooling system. Appendix D states, in part, that "[t]o prevent an excessive buildup of . . . gases from occurring, venting on the operating train **shall be performed** as follows: . . . Once per shift when the RCS is at midloop, vent **only** at the containment spray pump rooms . . ." [emphasis added].

The team noted that Section 2.0 of Appendix D was applicable because the Train B shutdown cooling loop was in service. The team noted that the following steps were required:

Step 2.5 **IF** RCS level is less than or equal to 103 foot 1 inch, **THEN** GO TO step 2.10."

Step 2.10 Throttle open SIB-V019. (Located just below the main level grating, Southwest corner of the CS Pump B Room)

Step 2.11 **WHEN** a solid stream of air free water issues from the vent, **THEN** close SIB-V019.

During the venting evolutions, while in reduced inventory, the team noted that the operators did not attain a solid stream of air free water from Valve SIB-V019 on five consecutive vents between 8:29 am MST and 4:32 pm MST on February 25. Additionally, the team noted that the operators also vented the shutdown cooling system from a seal cavity vent. That vent location was not in the containment spray pump rooms as specified in Appendix D to Procedure 40OP-9SI01.

Additionally, the team found that the procedure did not specify additional testing if gas was found during venting, (e.g., sampling of the gas by chemistry technicians to determine the source of the gas, or ultrasonic testing of upstream piping to determine where the gas voids may be accumulating). During the 44 hours that Unit 2 was in midloop condition (from February 23 to February 25), licensee personnel did not evaluate where the gas was accumulating nor analyze the gas.

Analysis. The team determined that the failure to properly vent the shutdown cooling system while in reduced inventory could, if left uncorrected, become a more significant safety concern. The team found that the inadequate venting was associated with the operability, availability, and function of the shutdown cooling system while in reduced inventory (i.e., potential loss of long term decay heat removal).

The team noted that the venting of the operating shutdown cooling train had protected against gas accumulation in amounts sufficient to cause a loss of the operating pump. During the time period of concern, the team noted that the motor current for the Train B low pressure safety injection pump did not fluctuate, indicating that air intrusion was less than 2 percent by volume. The licensee engineers provided information to the team that showed the pump would remain operable with entrained air in an amount of 2 percent by volume.

The team determined that the air equivalent to 2 percent by volume was approximately 8 gpm. From a previous calculation (see Section 3.2, below), the team noted that the ingestion of air into the shutdown cooling system, as a result of vortexing while in reduced inventory, was approximately 1 to 2 quarts per minute, significantly less than the amount calculated to impact operability.

The team found that the operators' actions could have contributed to an increased risk of losing shutdown cooling or inventory control by not correctly implementing the procedure (i.e., not attaining a steady stream of water and venting from a location prohibited by the procedure). However, the failure to implement the procedural requirements had little actual impact on safety under the given situation since there was no loss of shutdown cooling or inventory control.

After evaluation of the failure to correctly implement the venting procedure through the Significance Determination Process, the team found this performance issue to be of very low safety significance (GREEN). The bases for this finding is none of the plant conditions met the threshold for performing a Phase 2 analysis, in accordance with Appendix G, *Shutdown Operations Significance Determination Process,* of NRC Inspection Manual Chapter 0609, *Significance Determination Process*.

The team also found that the operators did not demonstrate a questioning attitude as to how much air was in the system, where the air was accumulating, or if the air was passing through the system.

The team found that this finding has cross-cutting implications in the human performance area. That is, this violation was the direct result of operators not correctly implementing a procedure.

<u>Enforcement</u>. Technical Specification 5.4.1a. requires that "[t]he applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978" shall be implemented. Regulatory Guide 1.33, *Quality Assurance Program Requirements (Operation)*, Appendix A, includes procedures for ". . . Startup Operation and Shutdown of Safety-Related PWR Systems." Further, those procedures are to include "[i]nstructions for energizing, filling, [and] venting . . . [the] [s]hutdown [c]ooling [s]ystem."

Contrary to the above, the operators failed to correctly implement Appendix D of Procedure 40OP-9SI01 by not attaining a solid stream of air free water from Valve SIB-V019 and venting from a location not specified in the procedure.

This finding is being considered a noncited violation (NCV 05000529/2004009-001) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered this issue into its corrective action program as Condition Report/Discrepancy Request 2686273.

3.2 Assessment of the Licensee's Determination of the Cause of the Gas Entrainment

a. <u>Scope</u>

The team reviewed the licensee’s cause determination of the gas entrainment. This included a review of an evaluation of the licensee's response to Generic Letter 97-04, *Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps*, to address the effects of air entrainment in the suction line of the low pressure safety injection pump while in the recirculation mode from the containment sump.

b. <u>Observations and Findings</u>

The team noted that licensee engineers identified the cause of the gas accumulation to be entrainment of air at low levels (on the order of one to two quarts per minute) into the operating shutdown cooling train. While in midloop condition, the licensee engineers postulated that air was being pulled from the surface of the water via vortexing at the location of the shutdown cooling tap in the reactor coolant piping and drawn into the flowpath of the running low pressure safety injection pump. The licensee engineers determined that some of those bubbles could come out of solution and accumulate in the elevated piping adjacent to the low pressure safety injection pump. Because the plant was operated with reduced inventory without a venting operation until approximately 20 hours after reaching midloop, the team and licensee engineers determined that gas accumulated in amounts sufficient to void sections of the high point piping.

The team found that the average time spent in midloop condition for the three Palo Verde Nuclear Generating Station units was approximately 14 hours, a significantly shorter time than during this outage, over the previous 10 refueling outages. The team found the fact that the plant was not normally subjected to such a length of time in reduced inventory to be a contributing factor to the operators not expecting the amount of voiding that occurred.

3.3 Comprehensiveness of the Licensee's Determination of the Extent of Condition and the Adequacy of Planned or Completed Corrective Actions

a. Scope

Through interviews and documentation reviews, the team evaluated the comprehensiveness of the licensee's extent of condition review for the gas entrainment condition that occurred during midloop conditions on Unit 2. The team also reviewed the adequacy of the licensee's corrective actions in response to the gas entrainment condition that occurred during midloop conditions on Unit 2. Specifically, the team assessed whether licensee personnel had previous opportunities to identify and correct the midloop accumulated gas condition.

b. Observations and Findings

The team found that licensee engineers had reviewed previous corrective action documents in order to determine if this condition had occurred before. No previous instances of similar gas voiding were identified by either the licensee engineers or the team. Detailed reviews of external operating experience did not identify this particular condition (i.e., large gas voiding due, in part, to extended operation in midloop condition) occurring at other domestic nuclear power plants.

The team also found that the corrective actions, in response to the identification of air accumulation as a result of vortexing while in reduced inventory, were being applied to all three units. Refer to Section 3.4 for a detailed discussion of the licensee's corrective actions.

The corrective actions planned or completed by the licensee at the end of the Special Inspection included, but were not limited to, the following:

- Reducing shutdown cooling flow to the lower end of the 3780 to 4150 gpm operating band to help preclude vortexing

- Maintaining reactor vessel level at the upper end of the operating band (approximately 101 feet 10 inches elevation) to help preclude vortexing

- Increasing the frequency of venting operations while in midloop conditions from once per shift (i.e., every 12 hours) to once every 2 hours

- Creating a specific acceptance criteria for the amount of entrained gas within licensee Procedure 40OP-9SI01

The team found that the planned corrective actions, being applied to all three units, would address the issue of air ingestion into the shutdown cooling system as a result of vortexing while in reduced inventory. Corrective actions are being tracked via Condition Report/Disposition Request 2686273.

3.4 Degraded Hot-Leg Nozzle Dams

a. Scope

The team reviewed Change Report PV-DCR-10-000075, *DCR for the Nozzle Dam Ring Slot Dimensions*, Revision 0, to understand the corrective actions taken to address the undersized slots. The team also reviewed the activities of the licensee personnel with respect to pre-installation testing and the attempted installation of the nozzle dams during this forced outage.

b. Observations and Findings

Introduction. An apparent violation was identified for the failure to promptly identify and correct a condition adverse to quality. Specifically, licensee personnel failed to identify, prior to putting the Unit 2 steam generators in service, that the nozzle dams used for allowing examination of the tubes would not fit properly in the new locking rings.

Description. During the fabrication of the replacement steam generators, licensee personnel sent a set of nozzle dams to the fabricator for installation testing. These nozzle dams were not the ones that are used in the plant, but were of similar design. The fabricator was not able to successfully engage the locking pins on Steam Generator 21. The cause was determined to be an interference between the lock pins and the locking ring slots. The team learned that the lock pins used during the trial fit were the standard size pins. The corrective action was to grind the slots to increase the opening. This was to be done for both steam generators.

A fabricator initiated Change Report PV-DCR-10-000075 to document the required change in the dimension of the locking ring slots. The team noted that the change in dimensions was to be applied to both steam generators. However, the fabricator did not provide as-built drawings to show the actual dimensions for the locking ring slots.

The team noted that, during the installation of the steam generators, licensee personnel did not perform a test fit of the actual set of nozzle dams that would be used during an outage. The core was off-loaded at the time of installation of the steam generators.

On February 24, 2004, during the installation of the Steam Generator 22 hot-leg nozzle dam, the maintenance personnel experienced difficulties inserting the lock pins. The maintenance personnel noted that more force was needed to insert the pins than was used for the installation of the other nozzle dams.

After the installation of the hot-leg nozzle dam in Steam Generator 22, operators received a *SG 2 Hot Leg Nozzle Dam Pressure High* alarm. The alarm remained after maintenance personnel adjusted the appropriate pressure regulator. Maintenance personnel performed a pressure drop test and determined that the dry seal was leaking instrument air into the annulus area, resulting in the high pressure alarm. These activities were occurring approximately 7 hours after entering reduced inventory.

The team learned that the nozzle dam was qualified for approximately 22 psid across the passive seal. If there was a loss of shutdown cooling during a station blackout (worst-case scenario) there could be up to 50 psid across the nozzle dam. Since the nozzle dams had been qualified to approximately 22 psid across the passive seal, licensee engineers determined not to use the nozzle dam on the passive seal alone. The licensee engineers informed the team that there was information available to support the use of the passive seal alone, but that information had not been validated. Therefore, the licensee engineers decided to be conservative and replace the diaphragm.

After the installation of the second diaphragm, the maintenance personnel noted that it too had an air leak. This was noted after being in reduced inventory for approximately 30 hours.

The team noted that the maintenance personnel had identified that significant force was also required to install the replacement diaphragm. The team learned that plant engineering personnel had identified the need to use a set of "shaved" pins for the installation of the replacement diaphragm. However, maintenance personnel installing the replacement did not use the "shaved" pins.

The team noted that the "shaved" pins were approximately 0.120 inches thinner at the end where the pin entered the locking ring slots, reducing any interference fit concerns. The "shaved" pins were available to be installed, but maintenance personnel decided that it would take too long to replace the standard pins and they did not understand the need for the "shaved" pins. Therefore, the maintenance personnel proceeded with the standard pins.

Subsequently, another replacement diaphragm was obtained and was successfully installed with the "shaved" pins. The operators refilled the primary and exited reduced inventory after approximately 44 hours.

Analysis. The team found several missed opportunities associated with the problems encountered during the installation of the nozzle dams. First, the licensee did not require as-built drawings or measurements for the locking ring slots and lock pins. Second, licensee personnel did not perform any measurements or test fits to ensure that the nozzle dams would fit in the actual steam generators during the installation process. Third, the mechanical maintenance leader modified the directions of the engineering staff without obtaining an agreement that such modification was acceptable.

The team determined that the failure to identify the incompatibility of the nozzle dams and the locking rings prior to placing the steam generators into service was a failure to promptly identify an adverse condition. The team further found that the failure to use the "shaved" pins was a failure to promptly correct an adverse condition. The team found these to be a violation of Criterion XVI, *Corrective Action,* of Appendix B to 10 CFR Part 50.

The team attempted to assess this finding through the use of the guidance of Appendix G of NRC Inspection Manual Chapter 0609. Appendix G is to be used during forced outages when the plant has met the entry conditions for shutdown cooling and shutdown cooling has been initiated. The purpose of Appendix G is to assess the potential for an inspection finding to be risk-significant. If the plant conditions during the time period the finding occurred meet the threshold in the checklist, then more detailed risk analysis is needed. This is similar to the Phase 1 screening for findings at power operations.

The team found that, when the checklist of Appendix G was developed, the authors did not consider that the length of time a plant operated in reduced inventory could result in increased risk, requiring a more detailed risk analysis. The team found that the failure to promptly identify and correct the nozzle dam fit issue resulted in an increase in the time the plant was vulnerable to a loss of shutdown cooling or a loss of inventory control. However, Appendix G was not adequate to reach a determination of the risk. A feedback form will be generated for the Office of Nuclear Reactor Regulation to review, assess, and revise the procedure, as necessary. A detailed risk analysis will be performed by NRC risk analysts to determine the final significance.

The team found that this finding has cross-cutting implications in the problem identification and resolution area. That is, this finding was the direct result of licensee personnel's failure to promptly identify and correct a condition adverse to quality.

Enforcement. Criterion XVI, *Corrective Action,* of Appendix B to 10 CFR Part 50, requires, in part, that measures shall be established to assure conditions adverse to quality are promptly identified and corrected.

Contrary to the above, the established measures did not assure that conditions adverse to quality were promptly identified and corrected. Specifically, licensee personnel failed to identify that the locking ring slots were not adequately sized to allow the use of the standard lock pins, contributing to the damage to the diaphragms. After plant engineers assessed the cause of the damage to the diaphragm, licensee personnel failed to correct the condition by not implementing the actions recommended by plant engineers.

This finding is an apparent violation (AV 05000529/2004009-002) pending a risk determination by the NRC. An apparent violation is a noncompliance with a regulatory requirement, regardless of possible significance or severity level, that has not been formally dispositioned by the NRC. The licensee entered this issue into its corrective action program as Condition Report/Discrepancy Requests 2686201 and 2686271.

4 Primary-to-Secondary Leak

4.1 Effectiveness of Tube Pre-Service Examination Methods

a. Scope

The team reviewed the examinations and inspections performed during manufacturing of the tubing and steam generators.

b. Observations and Findings

Introduction. A noncited violation of very low safety significance was identified for the failure of the corrective action process to identify and correct a condition adverse to quality.

Description. The steam generator tubes at Palo Verde Nuclear Generating Station, Unit 2, were produced by Sandvik to American Society of Mechanical Engineers (ASME) Specification SB-163. Ultrasonic testing and eddy current techniques were used to examine the tubing at Sandvik. Hydrostatic testing at a pressure of 3150 psi was also performed after bending the tubes. The pressure was held for 5 seconds with the requirement that there be no leakage and no pressure drop. After fabrication and testing, the tubes were crated and shipped to Ansaldo, the steam generator manufacturer.

At Ansaldo, the tubing was removed from the packing crates and inserted into the steam generator tubesheet. Receipt inspection of the tubes, identified in the tube installation procedure, consisted of inspection after removal from the storage box for contamination such as discoloration, pitting, damage, etc., and the tubes were to be continually observed during handling and insertion for damage. A nonconformity report was written in October 2001 at the steam generator manufacturer’s site identifying a tube that had been punctured by a packaging crate screw. This condition was noticed during fabrication of Steam Generator 22. Steam Generator 21, the affected (leaking) steam generator, had all of the tubes installed at that time. The team was informed that the section of damaged tube was sent back to the tube manufacturer. The team did not identify any other corrective actions taken by either the licensee's quality assurance inspector or the fabricator's personnel to ascertain whether the tubes already installed in Steam Generator 21 or 22 could similarly be affected. Licensee representatives reported that no procedure changes regarding receipt inspection were made to address potential tube damage from the crating process at the time of discovery. However, a licensee employee stated that licensee's onsite quality control inspector was shown the damaged tube to alert him to the potential for this type of damage.

In response to the nonconformity report, written at the steam generator manufacturer’s site, the licensee representatives determined that the tube manufacturer took corrective actions in June 2002. Those corrective actions included changing to a different type of screw and altering the screw location in the spacer. Personnel involved with packaging the tubes were also briefed at that time.

A helium leak check and hydrostatic pressure test were performed after construction of the steam generators. The helium leak test was performed at 30 psi. The helium leak test was followed by the hydrostatic pressure test, which was performed at 125 percent of design pressure. Both Palo Verde Nuclear Generating Station Unit 2 steam generators satisfactorily passed the two tests.

After being shipped to the Palo Verde Nuclear Generating Station site, a preservice examination was performed by licensee personnel prior to installation of the steam generators into the plant. The preservice examination was performed in accordance with *EPRI Pressurized Water Steam Generator Examination Guidelines*, Revision 5, and included bobbin coil examination of the tubes from tube-end to tube-end. Rotating probe examinations were performed on all indications of possible degradation, a sample of manufacturer's burnish marks, a sample of dents, the U-bends of Rows 1 and 2 tubes, and in the flow distribution baffle area. The rotating probe examinations of the dents focused on dents located in the hot-leg and larger dents. Dents were reportable during the primary analysis if the indication exceeded 0.5 volts on the 500/100 kHz mix channel.

Independent analysis of all data was performed by primary and secondary data analysts. For the bobbin coil data analysis, a computerized, automatic data screening system was used as the primary data analyst and 10 percent of this data was spot-checked by a human analyst. Secondary data analysis of the bobbin coil data was performed by a human analyst. The primary and secondary data analysis of the rotating probe data was performed by human analysts. A primary resolution analyst was responsible for resolving differences noted between the primary and secondary analysis reports. A secondary resolution analyst was employed to confirm potentially nonconservative decisions made during the primary resolution analysis of the data.

Although licensee personnel were informed of the nonconformity report identifying a tube pierced by a screw, the individuals responsible for the preservice examination either had not fully reviewed the information or were not aware of the potential for such a defect to occur until after the preservice examination began. Upon receiving this information no changes were made to the preservice examination program to ensure detection of similar damage.

During the preservice examination, the dent on the leaking tube was part of the sample population. The primary and secondary analysts identified a 15-volt dent during the evaluation of the bobbin coil data of the tube in Row 156, Column 143 (Tube R156C143). The primary data analyst, during review of the rotating probe data, identified that the indication required lead analyst review. The secondary data analyst of the rotating probe data identified a 1.93-volt dent at this location. The dent signal was atypical from dents routinely observed in the Palo Verde Nuclear Generating Station steam generators due to the vertical component of the signal on the eddy current lissajou plot. The primary resolution analyst identified the indication as a 1.93-volt dent. No further action was taken with respect to this indication.

Analysis. The team concluded that licensee personnel clearly missed several opportunities to have identified the leaking flaw as part of the steam generator fabrication and preservice examination. These missed opportunities include (1) not assessing whether the tubes already installed in Steam Generators 21 and 22 could have damage from a screw upon identification of one tube with similar damage, (2) not effectively communicating the potential for flaws associated with mechanical damage to exist in the tubes as a result of the fabrication process and not making the inspectors performing the preservice examination aware of this possibility, and (3) not recognizing the significance of the anomalous rotating probe signal associated with the dent in Tube R156C143.

The team found that the failure to properly address the identification of a screw-generated flaw through the corrective action program was more than minor because it had actual safety consequences (i.e., a steam generator tube leak). This finding affects the barrier integrity cornerstone because of the potential to release radionuclides through the leaking tube. Reactor coolant system barrier performance was the affected attribute.

The team performed a Phase 2 evaluation of the significance of this finding using the Manual Chapter 0609, *Significance Determination Process*, because the tube leak affected the barrier integrity cornerstone. Table 3.7, *SDP Worksheet for Palo Verde Nuclear Power Station - Steam Generator Tube Rupture (SGTR)*, was used to evaluate this finding. Applying the results obtained from Table 3.7 to the counting rule worksheet, the team determined that the significance of this finding could be greater than very low. After a Phase 3 evaluation using Manual Chapter 0609, a Senior Risk Analyst determined that the safety significance was very low.

The team found that this finding has cross-cutting implications in the problem identification and resolution area. That is, this finding was the direct result of the engineering staff's failure to properly address and correct a condition adverse to quality.

Enforcement. Criterion XVI, *Corrective Action,* of Appendix B to 10 CFR Part 50, requires, in part, that measures shall be established to assure conditions adverse to quality are promptly identified and corrected.

Contrary to the above, the established measures did not assure conditions adverse to quality were promptly identified and corrected. Specifically, although a tube was identified with damage from a packing crate screw during steam generator fabrication, the licensee’s corrective action program did not assure that the adverse condition (i.e., inadequate packing of tubes) was promptly corrected during fabrication of the Unit 2 steam generators. (As a result of the tube leak, the problem has since been corrected for fabrication of Unit 1 steam generators.) Additionally, the corrective action program was deficient, in that, there was no mechanism to insure that adverse conditions identified by the fabricator were made known to the appropriate licensee personnel. As a result, the potential for a damaged tube to exist in the steam generators installed in the plant was not assessed, nor were actions taken to support detecting a damaged tube during the pre-service examination.

This finding is considered a noncited violation (NCV 05000529/2004009-003) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered this issue into its corrective action program as Condition Report/Discrepancy Request 2685303.

4.2 Effectiveness of In-Service Examination Methods

a. Inspection Scope

The team reviewed (a) the actions taken to identify the leaking tube, (b) eddy current data from a select number of tubes acquired during the current outage, and (c) the in-situ pressure test results.

b. Observations and Findings

After shutting down the plant, licensee personnel performed a secondary side pressurization test in Steam Generator 21. This testing identified leakage from the hot- and cold-legs of the Tube R156C143, which is a peripheral tube. Nondestructive examination personnel performed a full-length bobbin probe inspection of this tube, but did not identify any through wall degradation that could be the source of the leakage. A 15-volt dent near the central vertical support in the middle of the horizontal run of the leaking tube was observed. This dent was also present in the preservice examination data of the steam generator tubes.

A full length rotating probe examination was performed on the leaking tube. No clear indication of the leak source was identified; however, the signal associated with the dent in this tube was anomalous. Review of the rotating probe data of this dent from the preservice examination also indicated that the anomalous signal was present. Comparison of the dent signal from the preservice examination with the signal obtained during the forced outage showed a slight amount of change in the dent signature at this tube location.

Since eddy current testing of the affected tube did not provide conclusive evidence of a through wall flaw, licensee personnel conducted a primary side pressure test of the affected tube up to a pressure of 1200 psi. No evidence of leakage was observed. After depressurization, a camera was used to visually examine the dent with the secondary side water level above the tube level. A droplet appeared to form at the dent; however, the examiners decided that the results were not conclusive. The nondestructive examination personnel then performed a full length in-situ pressure test and 0.05 gpm leakage was observed at normal operating differential pressure, 0.08 gpm was observed at main steam line break differential pressure, and 0.09 gpm was observed at three times normal operating differential pressure with the tube maintaining structural integrity. The team verified that equilibrium was reached at each pressure hold point during the in-situ pressure test. The team also noted that, when the postulated accident (e.g., main steam line break) leakage was corrected to reflect accident plant conditions (e.g., operating plant temperature and pressure), the computed leak rate ranged from 0.04 gpm to 0.08 gpm depending on the calculation method used (e.g., EPRI In-Situ or NUREG CR-6444).

Nondestructive examination personnel reviewed the rotating probe data for all dent signals acquired during the preservice examination to ascertain whether similar anomalous dent signals existed. One additional tube in Steam Generator 22 had been identified with such a signal, but was not conclusively similar to that for Tube R156C143 with respect to the vertical presentation of the eddy current signal. This tube, R41C200, had been plugged during the preservice examination because the dent obstructed the passage of the normal sized bobbin probe and the licensee was concerned with the future examination of this tube.

The nondestructive examination personnel performed additional bobbin probe and rotating probe examinations in the steam generators. Bobbin probe examinations focused on areas of the steam generators historically susceptible to degradation and a sample of tubes surrounding the leaking tube. Approximately 100 tubes in the affected steam generator were inspected and no additional degradation was identified.

Rotating probe inspections were performed in both steam generators on all dents identified during the preservice examination with bobbin dent voltages greater than 5 volts if those dents had not been inspected during the preservice examination with a rotating probe. No anomalous dent signals were identified. In the affected steam generator, the nondestructive examination personnel also inspected all dents with the rotating probe with voltage signals greater than 2 volts if those dents had not been examined during the preservice examination with a rotating probe. Approximately 50 additional rotating probe examinations were performed in Steam Generator 21, and 8 rotating probe examinations were performed in Steam Generator 22. No anomalous signals were identified during the examinations.

To simulate the anomalous dent signal in Tube R156C143, nondestructive examination personnel created a series of dents in their mock-up facility. The simulation included impact dents from a nail, a screw, and a drill bit. A wood screw, similar to that used in the tube manufacturer's crate, was driven through a piece of wood and into the sample tube. Eddy current testing was performed on these simulations and the damage caused by the wood screw yielded a similar anomalous signal to that of Tube R156C143.

The nondestructive examination personnel concluded that the examinations and tests conducted during the forced outage provided reasonable assurance that the condition was bounded and isolated to Tube R156C143. Their basis includes causal information which indicates that:

- A leaking dent indication will result in an anomalous +Point™ dent signal with "flaw-like" vertical extent.

- A leaking dent indication will have a bobbin dent signal in excess of 8 volts. A total of 180 dent signals ranging from 2 volts to 52 volts were reviewed. Only two tubes (R156C143 and R41C200) had recordable "flaw-like" signals.

- The potential for dents caused by similar shipping conditions as Tubes R156C143 and R41C200 was addressed. All tubes with dents greater than 2 volts were examined with a +Point™ coil.

- A review of industry data did not reveal any leakage from Alloy 690 tubes as a result of denting despite a significant population of dents in excess of 5 volts.

The nondestructive examination personnel concluded that the leaking tube had structural integrity (i.e., did not burst at three times normal operating differential pressure), and the leak rate for this one tube under postulated accident conditions was below the allowable leak rate of 0.5 gpm per steam generator (720 gpd). In addition, a statistical evaluation performed by licensee personnel indicated that there is a 95 percent probability that no more than three similar defects could exist in dents greater than 2 volts. This evaluation took no credit for the distributional relationship of through-wall defects to dent voltage. If three such similar indications were left in the steam generator, the corresponding leak rate under postulated accident conditions would still be within allowable limits assuming a leak rate similar to that observed during the in-situ pressure test of the leaking tube.

A consultant to the team independently reviewed the preservice and inservice eddy current data for the leaking tube and data from selected other tubes. In addition, the consultant reviewed eddy current data from the licensee's "wood screw" mock-up. Based on this review, the consultant concluded there was not a large change between the preservice scan data and the inservice scan data. The consultant noted that the calibration and inspections between the two outages were enough different to account for differences in the bobbin examination and that the +Point™ examination results are a function of how the coil intersects with the flaw, which may vary from scan-to-scan.

The team found that the nondestructive examination inspection and test program provided reasonable assurance that the steam generators had adequate structural and leakage integrity. The team's finding is based on the following factors: the hydrostatic test results at the fabrication facility; the lack of any known service-induced degradation in Alloy 690; the similarities between the preservice and inservice examination results of the leaking tube; and the number of defects that would have to exist in order to challenge the leakage limit under postulated accident conditions.

4.3 Evaluation of Determination of the Source of the Leak

a. Inspection Scope

The team reviewed the licensee's actions to determine the source and cause of the leak.

b. Observations and Findings

The actions taken by licensee personnel to identify the leaking tube are discussed above. The licensee's personnel concluded that Tube R156C143 was leaking and they plugged this tube prior to returning the steam generators to service. No other tubes were plugged during this outage. Following the restart of Unit 2, there was no significant primary-to-secondary leakage, confirming the source of the leak was Tube R156C143.

Licensee personnel conducted a formal investigation to determine the fundamental cause of the leak (e.g., fabrication, corrosion, etc.). Licensee personnel assembled a list of facts that they thought to be pertinent to the cause of the leak. These facts included:

> The leaking tube (R156C143) and one other tube (R41C200 in Steam Generator 22) had anomalous dent signals. The dent in Tube R41C200 measured 52 volts and the tube was plugged prior to placing the steam generator in service in 2003.
>
> A similar dent (in visual presentation) to that in the leaking tube was found during the assembly of the steam generators. This dent was a result of a screw in the shipping box that had pierced the tube. This tube was scrapped prior to insertion into the steam generator.
>
> A comparison of the eddy current data from the leaking tube obtained in 2004 to the preservice examination eddy current data did not show any significant change.
>
> The location of the dent in Tubes R156C143 and R41C200 correspond to locations in the shipping box where wood spacers and screws would have been used in shipping these tubes.
>
> The tubing manufacturer postulated that a tube in the bottom of a shipping box may be susceptible to damage due to an errant screw.
>
> Visual inspection of the dent in Tube R156C143 does not appear to be the result of an impact or leverage.
>
> The steam generator fabricator’s procedures did not contain specific or direct provisions to inspect the tubes for damage from packing screws.
>
> The steam generator fabricator has subsequently (following the Unit 2 leak) identified additional tubes in steam generators being fabricated for Palo Verde Nuclear Generating Station, Unit 1, with damage from packing screws.

Based on their evaluation, licensee personnel concluded that the collected evidence established that deformation of a tube could occur during packaging of the tubes, prior to their installation in the steam generator. The package construction utilized spacer and cross brace materials that were assembled as the tubes were loaded into the “box” using common screws. The design of this packaging placed the screws in close proximity to specific locations on some tubes (tubes other than those on the bottom of the shipping box could potentially be affected). The location, shape, and size of the deformation in the leaking tube are consistent with damage that would occur if the packing were assembled incorrectly such that a screw penetrated completely through the packing materials and came in contact with the tube.

The team noted that, on the basis of the conclusions regarding the cause of the leak, several corrective measures have been or are being implemented. For example, the inspection procedures at the steam generator fabrication facility were upgraded to look for damage from a screw. In addition, additional mock-up testing has been initiated at Palo Verde Nuclear Generating Station to improve the capability to identify and characterize puncture-type flaws via eddy current testing. Licensee personnel have recommended to the steam generator fabricator that improvements be made in the packing procedure/design. In addition, licensee personnel requested information from the steam generator fabricator to identify the Unit 2 steam generator tubes that were shipped in package locations where packing screw damage was possible. Upon receipt of this information, nondestructive examination inspections, as deemed necessary, would be incorporated into the steam generator management program.

The team concluded that the licensee's conclusions regarding the direct cause of the tube leak are reasonable and that the actions being taken to confirm that other similar indications are prevented, identified, and/or removed from service, as appropriate, are reasonable.

4.4 Evaluation of Licensee's Corrective Action

a. Inspection Scope

The team reviewed the corrective actions taken by licensee personnel in response to the steam generator tube leak.

b. Observations and Findings

The corrective actions implemented by the licensee involved three sets of actions as follows:

The first set of actions was taken in direct response to the tube leak and included reviewing preservice examination data to ensure that no similar anomalous dent signals remained in service, performing additional rotating probe inspections of larger dents not inspected during the preservice examination (as discussed above) to confirm that similar anomalous signals were not present at these locations, performing bobbin coil inspections to identify whether degradation observed in the original steam generators was occurring in the replacement steam generators, and in-situ testing the leaking tube to ensure it had adequate integrity.

The second set of actions was taken in response to the identification of one tube being scrapped at the fabrication facility because of damage due to a screw and the similarities between this tube, the leaking tube, and the licensee's mockup. This second set of actions included adding additional Palo Verde Nuclear Generating Station quality control inspectors at the fabrication facility (since replacement steam generators for Unit 1 are being fabricated at this facility), modifying the receipt inspections performed (including procedural changes) on the tubes at the fabrication facility, evaluating/

modifying the packing procedure/design, and identifying the tubes that were shipped in package locations where packing screw damage was possible.

The third set of actions was taken in response to the team's concerns regarding the screening threshold for determining which dents to examine with a rotating probe and the capability to identify and characterize volumetric flaws located within a dent (e.g., puncture type defects). To address this concern, the licensee initiated additional mockup testing to improve the capability to identify and characterize puncture type defects.

The team found that the corrective actions listed above established reasonable assurance that significant indications, which could potentially challenge tube integrity, were identified. In addition, the team found that these corrective actions in conjunction with the licensee's planned corrective actions should serve to (1) limit the potential for similarly damaged tubes to be installed in future Palo Verde Nuclear Generating Station steam generators and (2) confirm the licensee identified tubes with similar damage to the leaking tube, but to a lesser extent.

4.5 Licensee's Response to the Leak

a. Scope

The team reviewed the actions of plant personnel in response to radiation monitor alarms and subsequent identification of a primary-to-secondary leak in Steam Generator 21. The team reviewed the operating logs and interviewed operations personnel.

b. Observations and Findings

The team found that the operations staff made a conservative decision to shutdown the plant with an indicated tube leak of between 4 and 22 gpd, depending on the method of determining the leak rate. The operators completed an orderly shutdown with no complications. The leak rate allowed by the technical specifications is 150 gpd, and the administrative limit is 75 gpd.

4.6 Observation of Steam Generator Examination Activities

a. Scope

The team observed steam generator examination activities for the identification of the leak and for demonstration of tube integrity.

b. Observations and Findings

The team noted that the testing to identify the specific steam generator tube that was leaking was performed using Procedure 73TI-9ZZ32, *Steam Generator Secondary Pressure Test*, Revision 6. During the test, the secondary side of the steam generator had a water level approximately 4 feet above the top of the tubes and was pressurized up to 600 psig while the primary side was empty. Licensee personnel were positioned to visually identify the leaking tube. During the ascent in pressure, leakage was observed in Tube R156C143 on both the hot and cold-legs. After reaching 600 psig, a 1-hour hold was established and the remaining tubesheet was visually examined on both legs. No other leakage was identified at any other locations. The leak rates were documented as follows:

	Hot-Leg	Cold-Leg
55 psig	36 drops/min	44 drops/min
600 psig	3 drops/min	200 drops/min

On February 25, 2004, analysts reviewed the eddy current examination history of Tube R156C143 and determined that a dent had been identified on that tube 0.73 inches to the hot-leg side of Vertical Support Plate 3. Licensee personnel made arrangements to conduct additional eddy current examinations on this tube and others, plus perform visual examination of the upper bundle of the steam generator in the vicinity of Tube R156C143.

Between February 25-27, 2004, the additional examinations were performed and the results evaluated by licensee and contracted analysts. The team and the analysts noted that Tube R156C143 displayed some minor changes in the test signal from the original eddy current examination. Additionally, evidence of a loose part was discovered, and subsequently removed, in the vicinity of Tubes R155C140, R154C141, and R156C141.

On February 27, 2004, licensee personnel decided to perform an in-situ leak test to verify that Tube R156C143 was the source of the leak. Work Order 2686847 was initiated to perform this test. The work order addressed installation of the in-situ test equipment, gradual pressurization of the primary side of the tube, and the presence of licensee inspection personnel in the secondary side to visually identify the leak. The team noted that the personnel involved in the test had a pre-test briefing to discuss the procedure and establish the communication links.

Prior to performance of the in-situ leak test, licensee inspection personnel, accompanied by a team member, entered the secondary side for an initial inspection. Neither the licensee representative nor the team member saw any obvious flaw or indicated leakage on Tube R156C143. Licensee personnel initiated the leak test on Tube R156C143 and inspected the tube at various pressures up to 1200 psig with no leakage identified. Licensee inspection personnel, accompanied by a team member, re-entered the secondary side of the steam generator and saw no evidence of leakage, although the location of the tube made it difficult to be absolutely sure that there was no leakage.

Subsequent to the in-situ leak test, licensee personnel made a decision to perform a full integrity in-situ test on Tube R156C143. Work Order 2687064 was issued on February 27, 2004, and the integrity in-situ test was performed on February 28, 2004. The test consisted of pressurizing the primary side of the tube at various pressure plateaus: normal operating pressure (1425 psig); main steam line break pressure (2850 psig); and three times normal differential pressure (4250 psig). The team noted that tube leakage started at 1500 psig with an uncorrected leak rate of 0.05 gpm (72 gpd). Upon full pressurization of the tube to 4300 psig, an uncorrected leak rate of

0.09 gpm (129.6 gpd) was calculated. The tube did not burst and all parameters remained below technical specification limits. Upon completion of the test, Tube R156C143 was mechanically roll-plugged in both the hot- and cold-legs.

Licensee personnel concluded, based on assessment of eddy current and visual examinations, in-situ leak test results, and plugging of Tube R156C143, that no additional defects were detected and all previously identified defects were within the structural and leakage design basis established for the steam generators. Based on this assessment, licensee personnel further concluded there were no operability issues associated with startup of Unit 2.

The team found that the tests and examinations performed by licensee and contract personnel were performed in accordance with approved procedures. The team found that, as discussed above, the flaw in Tube R156C143 would not have resulted in a failure at three times the operating differential pressure. Also, the team found that the leakage at the differential pressure expected for a main steamline break would have been significantly below the analyzed limit.

05 Meetings, Including Exit

On March 3, 2004, the team presented the status of the inspection to date to Mr. G. Overbeck, Senior Vice President, and other members of his staff. On April 6, 2004, the team leader conducted a telephonic status update with Mr. D. Smith, Plant Manager-Operations, and other members of the Palo Verde Nuclear Generating Station staff.

On April 8, 2004, the team leader conducted a telephonic exit meeting with Mr. J. Levine, Executive Vice President, Generation, and other members of his staff.

While proprietary information was reviewed, no proprietary information is included in the report.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

R. Badsgard, Senior Engineer, Steam Generator and Projects Group
S. Bauer, Department Leader, Regulatory Affairs
C. Churchman, Director, Steam Generator Replacement Project
D. Hansen, Senior Consulting Engineer, Steam Generator and Projects Group
D. Hautala, Senior Engineer, Regulatory Affairs
S. Jones, Section Leader, Maintenance Engineering
M. Karbassian, Section Leader, Steam Generator Replacement Project
J. Levine, Senior Vice President, Generation
D. Marks, Section Leader, Regulatory Affairs Compliance
D. Mauldin, Vice President, Engineering and Support
M. Muhs, Department Leader, Maintenance
K. Neese, Section Leader, Steam Generator Replacement Project
G. Overbeck, Senior Vice President, Nuclear
M. Pacholke, Section Leader, Steam Generator Replacement Project
R. Schaller, Department Leader, Engineering Support
D. Smith, Plant Manager, Production
D. Straka, Senior Consultant, Regulatory Affairs
K. Sweeney, Section Leader, Steam Generator and Projects Group
T. Weber, Section Leader, Regulatory Affairs
M. Winsor, Director, Engineering

NRC personnel

D. Dumbacher, Project Engineer, Projects Branch D
J. Melfi, Resident Inspector, Palo Verde Nuclear Station
G. Warnick, Senior Resident Inspector, Palo Verde Nuclear Station

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000529/2004009-02	AV	Failure to promptly identify and correct an incompatibility between steam generator nozzle dams and the locking rings (Section 3.4).

Opened and Closed

05000529/2004009-01	NCV	Failure to correctly implement the venting requirements of Procedure 40OP-9SI01 (Section 3.1).

05000529/2004009-02	NCV	Failure to enter a nonconformity report from the steam generator fabricator into the Palo Verde Nuclear Generating Station corrective action program (Section 4.1)

LIST OF DOCUMENTS REVIEWED

AB Sandvik Steel Vendor Documents

NUMBER	TITLE	REVISION
CP 5857	Hydrostatic Pressure Test	1
CP 5855	In-Service Inspectability	1
CP 5851	Ultrasonic Test	0
CP 5852	Eddy Current Test	1
QP 58	Quality Plan	4

AB Sandvik Steel Vendor Drawings

Series 2092, 2093, 2094, 2095, 2096, 3208, 3209, and 3210 showing Steam Generator Tube crating layouts

Ansaldo Energia s.p.a. Drawings

NUMBER	TITLE	REVISION
PV-DWF-21-020	Half Eggcrates Assembly	4
PV-DWF-21-021	Half Eggcrates - Upper and Lower Strips 2" Machining	1
PV-DWF-21-026	Half Eggcrates Strips Weld Lay-out	0
PV-DWF-22-021	Upper Tube Supports-Diagonal/Vertical Strip Assembly	1
PV-DWP-21-023	Half Eggcrates - Upper and Lower Strips, 1" and 2"	2

Ansaldo Hydraulic Test Reports

HYC 2 site, RSG 22 Primary Side, August 4, 2002
HYC 3 site, RSG 22 Secondary Side, August 6, 2002
HYC 5 site, RSG 21 Primary Side, August 13, 2002
HYC 6 site, RSG 21 Secondary Side, August 14, 2002

Ansaldo Nonconformity Reports

NUMBER	SUBJECT	REVISION
PV-NCR-20-UCN004	Tube Cleanliness	1
PV-NCR-20-UCN005	Tube Cleanliness	1
PV-NCR-22-UCN001	Diagonal-Vertical Strip Assemblies Items 66-1/011 to 66-1/204	1
PV-NCR-32-UCN005	Batwings Item 66-1, Tie Bars Item 66-2, Lock Bars Item 66-3	1
PV-NCR-32-UCN009	SA 32 Tubing	1
PV-NCR-32-UCN016	Diagonal Vertical Strips Assembly	1
PV-NCR-32-UCN021	Arch Plates Assembling to the Batwings on Tube Bundle	1
PV-NCR-32-UCN028	Arch Plates Assembling to the Batwings on Tube Bundle	1
PV-NCR-33-UCN006	Accelerometer and Handling Pads	2
PV-NCR-40-UCN016	Snubber Lugs Final Machining and Key Lug Welding Completion	3
PV-NCR-40-UCN017	Snubber Lugs Final Machining and Key Lug Welding Completion	3
PV-NCR-40-UCN019	Torque of Bolts on Flow Blocker	0
PV-NCR-40-UCN020	Flow Blocker Interference	1
PV-NCR-40-UCN024	Pressure Test, Sampling and Level Nozzles	1

Ansaldo Nonconformity Reports

NUMBER	SUBJECT	REVISION
PV-NCR-40-UCN025	Pressure Test, Sampling and Level Nozzles	2
PV-PCF-40-UCNA09	Flow Blocker Assembly at the 270° Handhold Item 89 Repair	1

Condition Reports/Disposition Requests

2619106
2685303
2686201
2686271
2686273

Discrepancy Notices

6000469	6000478	6000512	6000533	6000567
6000470	6000479	6000513	6000537	6000569
6000471	6000480	6000514	6000544	6000579
6000472	6000490	6000515	6000545	6000580
6000473	6000491	6000516	6000546	6000593
6000474	6000492	6000521	6000552	6000594
6000475	6000497	6000531	6000553	6000619
6000476	6000504	6000532	6000566	6000620
6000477				

Drawings

NUMBER	TITLE	REVISION
02-P-SIF-105, Sheet 2 of 3	Containment Building Isometric Safety Injection System Shutdown Cooling Lines	5
02-P-SIF-202, Sheets 1 and 2 of 2	Number“Auxiliary Building Isometric Safety Injection System ESF Pump Suction Lines - Train B	3
02-P-SIF-208, Sheets 1 and 2 of 2	Auxiliary Building Isometric Safety Injection System LPSI & Cont. Spray Disch. - Train B	3

Drawings

NUMBER	TITLE	REVISION
02-P-SIF-136, Sheets 1 and 2 of 2	Containment Building Isometric Safety Injection System HP & LP Lines Loop 2A, 2B	1
02-M-SIP-001	P&I Diagram Safety Injection & Shutdown Cooling System	24
02-M-SIP-002	P&I Diagram Safety Injection and Shutdown Cooling System	21

Miscellaneous Documents

NUMBER	TITLE	REVISION / DATE
	Engineering Analysis “Estimate of Air Void in Unit 2 SDC-B on 2/24/04"	February 28, 2004
	List of Previous 10 Reduced Inventory/hot Core Mid-loop Refueling Outages for All 3 Palo Verde Units Including Length of Time in Reduced Inventory or Mid-loop Conditions	
	Unit 2 Operations Logs	February 29, 2004
	Unit 2 Replacement Steam Generator Condition Monitoring Report	November 2003
	Unit 2 Short Notice Outage Midloop Timeline from February 19, 2004 to	February 26, 2004
02-MN-725	RSG Specification - Acceptable Materials	Change Notice 20
054-030057-PJW/GJP	APS Memorandum, “2004 Unit 2 Snow Midloop Brief”	February 20, 2004
NUREG-0897	Containment Emergency Sump Performance	1
Volume 40	Standard Training Manual, “Safety Injection System"	0

Procedures

NUMBER	TITLE	REVISION / DATE
40OP-9SI01	Shutdown Cooling Initiation	30C
40ST-9SI07	High Pressure Safety Injection System Alignment Verification	7
40ST-9SI13	Low Pressure Safety Injection System Alignment Verification	3
40OP-9ZZ16	RCS Drain Operations	38C
73TI-9ZZ32	Steam Generator Secondary Pressure Test	6
81DP-0DC13	Deficiency (DF) Work Order	14
81CP-9RC29	In-situ Pressure Test Using the Computerized Data Acquisition System	4
PV-SPG-00-U77510	Hydrostatic Test Of Replacement Steam Generator Primary and Secondary Side	10

Test Reports

Ansaldo Hydraulic Test Report HYC 5 site, RSG 21 Primary Side, August 13, 2002
Ansaldo Hydraulic Test Report HYC 6 site, RSG 21 Secondary Side, August 14, 2002
Ansaldo Hydraulic Test Report HYC 2 site, RSG 22 Primary Side, August 4, 2002
Ansaldo Hydraulic Test Report HYC 3 site, RSG 22 Secondary Side, August 6, 2002

Work Orders

NUMBER	SUBJECT	DATE
2551528	Steam Generator 21 Hot Leg Tube Inspection/Plugging Activities	November 21, 2003
2551529	Steam Generator 21 Cold Leg Tube Inspection/Plugging Activities	November 21, 2003

Work Orders

NUMBER	SUBJECT	DATE
2551532	Steam Generator 22 Hot Leg Tube Inspection/Plugging Activities	November 21, 2003
2551533	Steam Generator 22 Cold Leg Tube Inspection/Plugging Activities	November 21, 2003
2685754	Steam Generator 21 Tube Inspection/Plugging Activities	March 2, 2004
2686847	Perform Eddy Current and In-situ Test (Leak Test) on SG 21 Tube R156C143	February 27, 2004
2687064	Perform Integrity In-situ Test on SG 21Tube R156C143	February 28, 2004

ATTACHMENT 2

TIMELINE FOR THE EVENT

Clarifying Assumptions: all times listed below are Mountain Standard Time (MST) and are given in 24-hour format; all dates listed are 2004; and the activities refer to Unit 2, unless otherwise specified.

December 2003	Refueling Outage #11 for Unit 2 was completed. Replacement of both of the Palo Verde Nuclear Generating Station Unit 2 steam generators was completed; Unit 2 placed back on line.
January	Elevated primary to secondary leakage identified at approximately 0.3 to 0.4 gpd.
February 19 0700	Operations Director questioned indicated primary to secondary leakage (based on Xe-135) which had increased to 0.75 gpd.
February 19 1522	The licensee received unexpected RMS ALERT alarms on RU-142 Channels 1 and 2, Main Steam Line –16 Gamma Radiation Monitor, and began monitoring RCS parameters for indications of RCS leakage and notified their Effluents Department.
February 19 1530	Operations entered Excessive RCS Leak Rate Procedure 40AO-9ZZ02. NRC Resident Inspector was notified of entry into Abnormal Operating Procedure as well as plant management and Units 1 & 3.
February 19 1538	Received ALERT RMS alarm on RU-141 Channel 2, Condenser Gland Seal Exhaust Monitor.
February 19 1600	Operations management determined that a unit shutdown was required due to determination by Effluents Department that an approximately 11 gpd primary to secondary leak was in progress in Steam Generator 21. Commenced preparation of shutdown game-plan with assistance from Reactor Engineering.
February 19 1626	Received unexpected ALERT RMS alarm on RU-4, Steam Generator 21 Blowdown Monitor.
February 19 1631	Operations commenced boration at a rate of 17 gpm (for a total of 3224 gallons).
February 19 1650	Effluents technician reports that samples taken from Condenser Air Removal pump discharge at 1600 hours provide the following results for SG primary to secondary leakage: 2.3 gallons/day (based on Xe-135 concentrations) and 5.2 gallons/day (based on Xe-133 concentrations).

February 19 1823	Control room operators manually tripped the reactor from 21% rated thermal power.
February 19 2248	The Unit entered Mode 4.
February 20 0525	Operations placed shutdown cooling in service via Low Pressure Safety Injection Pump ‘B.’
February 20 0546	The unit entered Mode 5.
February 20 0900	Operations personnel completed initial vent on operating train of shutdown cooling. Vent was free of gas (i.e., stream of water solid from the valve).
February 21 0232	Completed second vent on operating train of shutdown cooling. Vent was free of gas.
February 21 0820	Completed third vent of operating train of shutdown cooling. Vent was free of gas. Venting frequency changed to every 3 days based on steady state conditions, as directed in procedure.
February 21 1543	Secured the two running Reactor Coolant Pumps. (This negated the steady state conditions that had been established, and consequently altered the venting frequency.)
February 21 2255	Performed vent of operating train of shutdown cooling. Vent was free of gas.
February 22 0333	‘B’ Charging Pump tripped on overcurrent condition. Auxiliary Operator reported electrical odor from pump motor. Pump is quarantined.
February 22 2251	Performed vent of operating train of shutdown cooling. Vent was free of gas.
February 23 0200	Commenced Reactor Coolant System (RCS) drain to Refueling Water Tank from an initial value of 55% pressurizer level. Target level is 113 feet elevation.
February 23 0547	Stabilized at an RCS level at 117.2 feet elevation in order to verify level indication agreement and monitor changes in reactor head level.
February 23 0830	Performed vent of operating train of shutdown cooling. Vent was free of gas.

February 23 0839	RCS level at 113 feet.
February 23 1151	Secured Charging Pump ‘A’ to commence draindown to midloop conditions.
February 23 1157	RCS level at < 111 feet. Entered reduced inventory condition.
February 23 1352	Stabilized RCS level at 103.65 feet for level indication comparisons.
February 23 1417	Operations crew recommenced RCS draindown. Level checks were satisfactory.
February 23 1440	Steam generator tubes begin draining based on constant RCS level of 103 feet.
February 23 2132	Performed venting of operating train of shutdown cooling. Vent was free of gas.
February 23 2140	Steam generator tube draining was completed. RCS level is less than 103.08 feet. Entered midloop conditions.
February 23 2233	Started Charging Pump A.
February 24 0027	Secured RCS draindown and stabilized level at 101.75 feet.
February 24 0039	Hot and cold-leg manways removed from both steam generators.
February 24 0511	Commenced installation of both cold-leg nozzle dams.
February 24 0553	Cold-leg nozzle dams installed and pressurized. Commenced installation of hot-leg nozzle dams.
February 24 0721	All nozzle dams installed and pressurized. Commenced fill of RCS to 118 feet using two Charging Pumps.
February 24 0726	Secured RCS fill due to SG 22 hot-leg nozzle dam alarms on high annulus pressure. Air regulator was adjusted after first alarm, but this action was unsuccessful in correcting the condition.

February 24 1500	The licensee discussed the status of SG 22 hot-leg nozzle dam. The high annulus pressure problem was believed to be due to either a faulty air regulator or a leaking seal. Troubleshooting subsequently determined the dry seal was leaking. Initial assessment was that flood up was permitted with the leaking dry seal since all 3 seals (wet seal, dry seal and passive seal) were redundant, with each being capable of meeting design requirements. However during Engineering review to verify design requirements, it was determined that the passive seal was only designed for a 20 psid pressure. The Loss of Shutdown Cooling analysis requires nozzle dams to withstand 50 psid, thus the passive seal could not be credited. Licensee discussions continued regarding acceptability of flooding up while relying solely on the functioning wet seal and a partially degraded dry seal. The licensee decided to remove SG 22 hot-leg nozzle dam to replace the affected seal.
February 24 1730	Performed vent of ‘B’ Containment Spray Pump suction at V019. At ½ turn open, constant gas vented for 7 minutes. At 1/4 turn open, got 34 minutes of air/water mixture before a solid stream of water issued from the vent. Operations personnel reduced shutdown cooling flow from approximately 4000 gpm to approximately 3850 gpm in order to minimize the quantity of gas in the piping.
February 24 2202	Removed hot-leg nozzle dam on Steam Generator 22.
February 24 2338	Newly installed nozzle dam on Steam Generator 22 hot-leg would not hold air pressure within the dry seal.
February 25 0829	Performed vent of Containment Spray Pump suction at V019 and seal cavity. With V019 open 1/4 turn, got constant air for 90 seconds followed by 20 minutes of an air/water mixture. Seal cavity vent was completely air free, i.e., solid water stream.
February 25 1030	Vented Containment Spray Pump ‘B’ suction at V019. With the valve 1/4 turn open, got constant air for approximately 60 seconds, then approximately 13 seconds of an air/water mixture.
February 25 1040	Vented Containment Spray Pump ‘A’ suction at V018 in order to verify no gas accumulation. Vent was free of gas, i.e., solid stream of water.
February 25 1211	Vented Containment Spray Pump ‘B’ suction at V019. With V019 open 1/4 turn, got constant gas for approximately 30 to 40 seconds, then approximately 14 minutes of an air/water mixture.
February 25 1338	Hot- and cold-leg nozzle dams removed on Steam Generator 22.

February 25 1430	Vented Containment Spray Pump B suction at V019. With V019 open 1/4 turn, constant gas vented for approximately 30 to 40 seconds, then approximately 29 minutes of an air/water mixture issued as V019 was gradually opened to 1 and 1/4 turns.
February 25 1632	Vented Containment Spray Pump B suction at V019. With V019 open 1/4 turn, got constant gas for approximately 30 to 40 seconds, then approximately 15 minutes of an air/water mixture as V019 was gradually opened to 1 and 1/4 turns.
February 25 1635	Steam Generator 22 manways installed.
February 25 1656	Commenced fill of RCS from indicated level of 101.76 feet to target of 118 feet using two charging pumps.
February 25 1755	Reactor Vessel level at 103.08 feet. Exited midloop conditions.
February 25 1843	Completed vent from containment spray pump suction piping at V019. Obtained 2 minutes of gas free water after 18 minutes of an air/water mixture. Operations personnel vented from SIB-V866 and V870, High Pressure Safety Injection A Header Vent Valve and Low Pressure Safety Injection Header Test Valve, respectively, and obtained air free water after 15 seconds of air/water mixture.
February 25 2038	Completed vent of B shutdown cooling train with gas free vents from all 3 venting locations. Venting frequency relaxed to once per shift.
February 26 0101	Reactor Vessel Level at 118 feet. Reduced inventory condition exited once level increased above 111 feet.