U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.	50-528/93-43, 50-529/93-43, and 50-530/93-43
Docket Nos.	50-528, 50-529, and 50-530
License Nos.	NPF-41, NPF-51, and NPF-74
Licensee	Arizona Public Service Company P. O. Box 53999, Station 9082 Phoenix, AZ 85072-3999
Facility Name	Palo Verde Nuclear Generating Station Units 1, 2, and 3
Inspection Conducted	September 21 through November 1, 1993
Inspection Location	Wintersburg, AZ
Inspectors	J. Sloan, Senior Resident Inspector H. Freeman, Resident Inspector A. MacDougall, Resident Inspector T. Alley, Department of Energy Inspector
Approved By	H. Wong, Chief Reactor Projects Section II — 11/19/93 Date Signed

Summary:

Areas Inspected: Routine, announced, resident inspection of:

- plant activities
- engineered safety features walkdowns - Units 1, 2, and 3
- surveillance testing - Units 1, 2, and 3
- plant maintenance - Units 1, 2, and 3
- local leak rate test valve failure - Unit 1
- fuel pin damage and debris in the reactor vessel - Unit 1
- fuel assembly recaging - Unit 1
- operability determination of shutdown cooling heat exchanger isolation valves - Unit 1
- low pressure safety injection pump breaker failure to close - Unit 1
- steam generator inspections - Units 1 and 3
- set pressure verification testing on SG-PSV-316 - Unit 2
- reactor trip - Unit 2
- simulator scenario observations - Unit 3
- job performance measure practice - Unit 3
- review of quality assurance audit reports - Units 1, 2, and 3
- accountability drill - Units 1, 2, and 3

- followup on previously identified items - Units 1, 2, and 3
- review of licensee event reports - Units 1, 2, and 3

During this inspection the following inspection procedures were utilized: 40500, 41500, 61726, 62703, 71707, 71710, 82301, 90712, 92700, 92701, 92703, and 93702.

Safety Issues Management System (SIMS) Items: None.

Results

General Conclusions and Specific Findings:

Strengths:

- The licensee's response to a loose jam nut on the turbine-driven auxiliary feedwater pump was thorough and rapid (Paragraph 2.d.(6)).

- The licensee identified and corrected an error in use of an incorrect revision of a procedure (Paragraph 4).

- Good coordination and communications between engineering and maintenance led to the successful removal and inspection of an emergency diesel generator bearing (Paragraph 5).

- Troubleshooting of several plant deficiencies was deliberate and appropriate in most cases (Paragraphs 5 and 6).

- The licensee exercised prudent judgment to mount a camera in the fuel canal to identify foreign objects in fuel assemblies being moved to the reactor vessel (Paragraph 7).

- Licensee procedures and careful Quality Control review prevented improper reconstitution of a fuel assembly (Paragraph 8).

- The licensee conservatively reduced reactor cold leg temperatures and limited reactor power to reduce the potential for mid-span axial cracking of steam generator U-tubes (Paragraph 11).

- The licensee was proactive in reviewing old steam generator eddy current testing data and identifying potential defects (Paragraph 11).

- One crew of operators demonstrated excellent command and control and good communications during a simulator scenario, and quickly mitigated the event (Paragraph 14).

- The licensee's Quality Assurance department continues to perform in-depth and thorough audits (Paragraph 16).

- The licensee implemented several good initiatives that contributed to significant improvement in performance during an accountability drill (Paragraph 17).

Weaknesses:

- A maintenance technician inappropriately completed a surveillance test action that should have been completed by the ASME Section XI engineer (Paragraph 12).

- A licensee technician used an incorrect revision of a surveillance test procedure (Paragraph 4).

Significant Safety Matters: None.

Summary of Violations: Of the 19 areas inspected, 2 non-cited violations were identified. One non-cited violation involved surveillance test performance not using the most recent revision of the procedure. The technician performing the test recognized the error and halted the test. The second non-cited violation involved the completion of a surveillance test on a relief valve by a maintenance technician rather than by the ASME Section XI engineer. One cited violation, regarding discrepancies in auxiliary operator rounds sheets, is also documented in this report for administrative purposes.

Summary of Deviations: None.

Unresolved Items: None.

DETAILS

1. Persons Contacted

The below listed technical and supervisory personnel were among those contacted:

Arizona Public Service Company (APS)

*	R. Adney,	Plant Manager, Unit 3
*	J. Bailey,	Assistant Vice-President, Nuclear Engineering & Projects
*	W. Bauer,	Supervisor, Quality Control
*	M. Baughman,	Supervisor, Operations Training
	R. Bouquot,	Supervisor, Quality Audits and Monitoring
	L. Clyde,	Manager, Operations, Unit 3
*	G. D'Aunoy,	PDE, Quality Audits and Monitoring
	J. Dennis,	Manager, Operations Standards/Plant Support
*	R. Flood,	Plant Manager, Unit 2
*	R. Fountain,	Supervisor, Quality Audits and Monitoring
*	R. Fullmer,	Manager, Quality Audits and Monitoring
*	D. Garchow,	Manager, Site Technical Support, Mechanical Engineering
*	F. Garrett,	Manager, Fire Protection Program
*	D. Gouge,	Director, Plant Support
*	B. Grabo,	Supervisor, Nuclear Regulatory Affairs
	W. Ide,	Plant Manager, Unit 1
	D. Leech,	Supervisor, Quality Audits and Monitoring
*	J. Levine,	Vice President, Nuclear Production
	D. Mauldin,	Director, Site Maintenance and Modifications
*	S. Moyers,	Supervisor, Site Maintenance Standards
	G. Overbeck,	Director, Site Technical Support
	R. Prabhakar,	Manager, Independent Safety and Quality Engineering
*	J. Reynolds,	Supervisor, Maintenance
*	F. Riedel,	Manager, Operations, Unit 1
*	C. Russo,	Manager, Quality Control
	J. Scott,	Assistant Plant Manager, Unit 3
*	C. Seaman,	Director, Quality Assurance and Control
*	R. Sorensen,	Manager, Site Chemistry Support
*	B. Whitney,	Auditor, Quality Audits and Monitoring
	P. Wiley,	Manager, Operations, Unit 2

Others

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

* Denotes personnel in attendance at the exit meeting held with the NRC resident inspectors on November 4, 1993.

2. Review of Plant Activities - Units 1, 2, and 3 (71707)

a. Unit 1

Unit 1 began the inspection period in refueling outage 1R4 with the core off-loaded. The unit entered Mode 6 on October 11, 1993, when core reload started. The core reload was completed on October 17, 1993. During this inspection period several pieces of debris were found in the reactor vessel (see Paragraph 7). On October 24, 1993, during an evolution to lower refueling water level, the "A" low pressure safety injection pump breaker failed to remain closed (see Paragraph 10). The unit ended the inspection period in Mode 5.

b. Unit 2

Unit 2 began this inspection period operating at 89% power. On September 23, 1993, the licensee reduced reactor power to 85%, which was determined to be the optimum power for minimizing steam generator tube dryout and deposit formation, and thus minimize tube degradation. The licensee stated its intention to operate at 85% power until the mid-cycle outage scheduled for February 1994. On October 14, 1993, power was reduced to approximately 65% to enhance steam generator chemistry cleanup (hideout return), and to repair a leak in the "2B" feedwater heater. When power was restored to 85% on October 15, the licensee also reduced reactor coolant system cold leg temperature to 556 °F to reduce stress on the steam generator tubes. At 8:08 a.m. (MST) on November 1, 1993, a reactor trip occurred due to low steam generator level following a sensed low voltage in a 4160 V nonsafety-related bus, NBN-S01 (see Paragraph 13). The unit ended the inspection period in Mode 3.

During this inspection period the licensee closely monitored available leak rate information and did not identify any primary-to-secondary leakage. Notably, the steam generator blowdown radiation monitors (RU-4 and RU-5) were out of service much of this period, apparently because contamination accumulated in the sample chambers which saturated the detectors. The licensee made attempts to flush and polish the detectors, and installed temporary monitors connected to the plant computer to provide an alternate indication of steam generator tube leakage. Additionally, the licensee installed N-16 monitors on the main steam lines during the last week of October 1993. The inspector concluded that licensee leak rate monitoring efforts were adequate.

c. Unit 3

Unit 3 began the inspection period at 100% power. Power was reduced to 75% on September 24, 1993, for chemistry control. The licensee determined that periodic power reductions would cause hide out return of contaminants, such as sulfites - a potential contributor to the mid-span axial cracking noted in Unit 2, which could subsequently be removed. Power was raised to 85% on September 26 following completion of steam generator cleanup. Power was limited to 85% as a precaution to help prevent dryout and the formation of deposits on the U-tubes.

The main turbine was taken off-line on October 9 to replace the electrical trip solenoid valve. The reactor remained critical at approximately 12%. Repairs were completed and reactor power was returned to 85% on October 10. Cold leg temperature was allowed to drop from 562 °F to 556 °F commencing on October 26 as a partial effort to reduce the effects of primary water stress corrosion cracking on the alloy 600 metal used in the U-tubes. Cold leg temperature reached 556 °F on October 29. Reactor power remained at 85% through the end of the inspection period.

Through this inspection period, primary-to-secondary leakage increased slightly from about 0.3 gallons per day (gpd) to about 0.5 gpd. The licensee closely monitored and trended the leakage. The inspector concluded that the leakage was not significant and that the licensee was adequately monitoring the leakage.

d. Plant Tour

The following plant areas at Units 1, 2, and 3 were toured by the inspector during the inspection:

- Auxiliary Building
- Control Building
- Diesel Generator Building
- Fuel Building
- Main Steam Support Structure
- Radwaste Building
- Technical Support Center
- Turbine Building
- Yard Area and Perimeter
- Containment Building (Unit 1 only)

The following areas were observed during the tours:

(1) Operating Logs and Records - Records were reviewed against Technical Specifications and administrative control procedure requirements.

(2) Monitoring Instrumentation - Process instruments were observed for correlation between channels and for conformance with Technical Specifications requirements.

(3) Shift Staffing - Control room and shift staffing were observed for conformance with 10 CFR Part 50.54.(k), Technical Specifications, and administrative procedures.

(4) Equipment Lineups - Various valves and electrical breakers were verified to be in the position or condition required by

Technical Specifications and administrative procedures for the applicable plant mode.

(5) Equipment Tagging - Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment was in the condition specified.

(6) General Plant Equipment Conditions - Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that could prevent the systems from fulfilling their functional requirements.

On September 23, 1993, the inspector noticed that the cover to the "A" remote shutdown panel transfer cabinet in Unit 1 was removed and left unattended for about three hours. There was not a barrier to prevent unauthorized work in the cabinet or to warn personnel if the equipment was energized. The inspector discussed this with a Quality Control inspector who contacted the responsible shop foreman and the cover was replaced. The inspector did not note any other problems with electrical panel covers not being replaced. The inspector concluded that the licensee's actions were appropriate.

In Unit 3, while touring the turbine-driven auxiliary feedwater (AFW) pump room, the inspector noted that the lower jam nut on the trip throttle valve (3-AFA-HV-54) position indication device was loose. The control room supervisor (CRS) immediately responded to investigate the condition and to determine the impact of the loose nut on the AFW pump operability. The CRS determine that the loose nut did not affect the pump's safety function. The inspector agreed with this conclusion.

Additionally, the licensee tightened the nut, inspected the jam nuts in Units 1 and 2 and reviewed work history files to determine if the loose jam nut was a generic problem. Further, the licensee reviewed work history files to determine if improper maintenance had left the jam nut loose. Although the licensee did not determine the cause of the loose nut, the inspector concluded the licensee conducted a thorough and appropriate investigation. The inspector also concluded that the licensee response was swift and commensurate with the safety significance of the AFW pumps.

(7) Fire Protection - Fire fighting equipment and controls were observed for conformance with Technical Specifications and administrative procedures.

(8) Plant Chemistry - Chemical analysis results were reviewed for conformance with Technical Specifications and administrative control procedures.

(9) Security - Activities observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures included vehicle and personnel access, and protected and vital area integrity.

(10) Plant Housekeeping - Plant conditions and material/equipment storage were observed to determine the general state of cleanliness and housekeeping.

(11) Radiation Protection Controls - Areas observed included control point operation, records of licensee's surveys within the radiological controlled areas, posting of radiation and high radiation areas, compliance with radiation exposure permits, personnel monitoring devices being properly worn, and personnel frisking practices.

(12) Shift Turnover - Shift turnovers and special evolution briefings were observed for effectiveness and thoroughness.

No violations of NRC requirements or deviations were identified.

3. Engineered Safety Features (ESF) System Walkdowns - Units 1, 2, and 3 (71710)

The inspector conduced a detailed walkdown of the essential cooling water system in all three units. The inspector specifically compared the system as-built with plant isometric drawings. Additionally, the inspector reviewed the system lineups and noted material conditions.

The inspector noted some material deficiencies which were discussed with licensee personnel. These deficiencies included excessive leakage from the Unit 2 essential cooling water pump "A" seal, and flaking lacquer in the Unit 1 essential cooling water pump "B" motor. The inspector concluded that these problems did not affect the operability of the systems.

The inspector also identified some deficiencies with the plant drawings. Drawing 02-M-EWP-001, Revision 9, was missing a quality class designation on train "B". Isometric drawings P-EWF-201 for all three units show hanger H-2 on line A-018-HBCB-20" below the floor penetration when the hanger was actually placed above the penetration. The inspector discussed these deficiencies with the licensee. The licensee reviewed the calculations to determine seismic adequacy of the supports and confirmed that the calculations were based on the as-built configuration.

Further, the inspector noted that several isometric drawings had not been updated to indicate where snubbers had been removed due to the snubber reduction program. A design engineer reviewed the hanger drawings to verify that the hanger drawings indicated that the snubbers had been removed. The inspector concluded that leaving the hanger symbol on the isometric drawing did not represent a configuration control problem, but represented a possible point of confusion by referring to a hanger which was not physically in the plant.

The inspector concluded that the essential cooling water systems in all three units generally matched the isometric drawings, were in good material condition, and were aligned according to procedures, and that they were being maintained in a manner to perform their safety functions.

No violations of NRC requirements or deviations were identified.

4. Surveillance Testing - Units 1, 2, and 3 (61726)

Selected surveillance tests required to be performed by the Technical Specifications were reviewed on a sampling basis to verify that: 1) the surveillance tests were correctly included on the facility schedule; 2) a technically adequate procedure existed for performance of the surveillance tests; 3) the surveillance tests had been performed at the frequency specified in the Technical Specifications; and 4) test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 1

Procedure	Description
32ST-9PK04	60 Month Surveillance Test of Station Batteries
41ST-1SI14	Section XI Low Pressure Safety Injection (LPSI) Pump Test
73ST-1CL01	Containment Leakage Type "B" and "C" Testing
77ST-9SB43	Core Protection Calculator/Control Element Assembly Computer Time Response Testing

On September 28, 1993, the inspector observed portions of surveillance test 77ST-9SB43, "Core Protection Calculator/Control Element Assembly Computer Time Response Testing," on channel "D." To perform the test, the technicians simulated a high pressure signal from the pressurizer pressure instrument and measured the time for the low departure from nucleate boiling ratio (DNBR) bistable to trip. When the technicians initiated the test signal, the timer remained at zero seconds. The technicians verified that the low DNBR bistable had tripped and did not note any obvious problems with the equipment. The lead technician marked the step "unsat" and made a test log entry. A problem was subsequently identified with the test equipment and the surveillance test was satisfactorily performed the next day. The inspector concluded that the technicians were deliberate and appropriately followed 73AC-9ZZ04, "Surveillance Testing," for documenting and resolving the noted problems.

On October 7, 1993, the inspector observed portions of surveillance test 41ST-1SI14, "Section XI Low Pressure Safety Injection (LPSI) Pump Test - 4.0.5" in Unit 1. During the surveillance test the LPSI pump suction check valve, SIA-V201, failed the acceptance criteria for preventing reverse flow. The operator marked the step "unsat" and documented the condition. The shift supervisor and the ASME Section XI engineer determined that the apparent problem with the check valve did not affect the operability of the LPSI pump. The check valve was designed to prevent flow from the reactor coolant system (RCS) to the refueling water tank during initiation of shutdown cooling if the isolation valve failed to close. Engineers subsequently determined that the existing test procedure could not be performed with the RCS depressurized. A new test procedure was written that required the upstream side of the check valve to be pressurized. The test was subsequently performed and the seat leakage was acceptable. The inspector concluded that the operators appropriately followed management's expectations for documenting the noted problem. Additionally, the inspector concluded that the operability determination for the LPSI pump was sound and that engineering's resolution of the problem was thorough.

Unit 2

Procedure	Description
36ST-9SB04	PPS Functional Test - RPS ESFAS Logic
42ST-2SG04	ADV and SBCV partial stroke test
73ST-2XI02	Section XI stroke time test
73ST-9ZZ02	Set pressure verification (see Paragraph 12)

Unit 3

Procedure	Description
36ST-9HP04	Containment hydrogen monitoring system calibration test, Channel "B"
36ST-9SA02	ESFAS Train "B" Subgroup Relay Monthly Functional Test

The inspector observed portions of surveillance test 36ST-9SA02, "ESFAS Train B Subgroup Relay Monthly Functional Test," on October 25, 1993. While performing Section 8.23 on containment isolation actuation signal (CIAS) train "B" relay K212, the technician realized that the improper response of relay K212 may have been caused by an ongoing evolution and determined that Section 8.23 should be reperformed after the evolution concluded. While copying Section 8.23 from the control room's controlled set of procedures, the technician recognized that the procedure being used (Revision 5.01) was not the latest revision (Revision 6). The technician secured further testing and informed Instrument & Control (I&C) supervision.

I&C personnel conducted a page-by-page comparison between the old and new revisions to procedure 36ST-9SA02 to determine the significance of using the old revision. The licensee determined that the changes to the procedure were editorial and did not affect the test. The surveillance testing procedure, 73AC-9ZZ04, required that the lead test performer verify the test package contained the most recent revision, by using a controlled copy of the procedure and the daily change list, or by contacting NIRM-DDC. The licensee determined that the lead test performer had contacted NIRM-DDC prior to starting the test and recorded the latest revision as 6. The licensee concluded that the lead test performer's failure to verify that the test package revision was up-to-date was an attention-to-detail problem and counseled the individual. The licensee-identified violation is not being cited because the criteria specified in Section VII.B of the Enforcement Policy were satisfied (NCV 50-530/93-43-01).

One non-cited violation of NRC requirements was identified.

5. Plant Maintenance - Units 1, 2, and 3 (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance/quality control department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspector verified that reportability for these activities was correct.

Specifically, the inspector witnessed portions of the following maintenance activities:

Unit 1

- Change tap setting on 4.16 KV to 480 Volt transformer
- Removal and inspection of diesel generator "B" center bearing
- Dynamic testing of valves SIA-HV-306 and SIA-HV-678
- Resistance temperature detector replacement on reactor coolant pump bearing
- Pin removal to test reactor coolant pump snubber
- Decontamination of spent resin transfer pump
- Assembly of SGN-V652, steam generator downcomer check valve
- Reactor vessel debris inspection

On October 4, 1993, the inspector observed the removal and inspection of the emergency diesel generator "B" center bearing in Unit 1. The coordination between the engineering personnel and the maintenance personnel was commendable. The activity had never been performed at Palo Verde and the two groups working together came up with a method for removing the bearing without injuring personnel or unnecessarily damaging the bearing. The inspector concluded that the licensee's performance was good.

Unit 2

- Coil resistance checks SGA-UV-134A (steam admission bypass valve to AFW pump)
- Coil replacement SGA-UV-134A
- Refurbish Class 1E, 480 V breaker

- Reactor coolant pump vibration monitoring
- Inspection and cleaning "B" amp discharge diaphragm

On September 22, 1993, the inspector noted that electricians measured the resistance of the coil of solenoid valve SGA-UV-134A, steam bypass valve to the turbine driven auxiliary feedwater pump. The resistance was measured to aid in resolving an issue regarding the equipment qualification life of target rock solenoid valves (see NRC Inspection Report 50-528/93-40, Paragraph 9). The measured coil resistance was about four thousand ohms, which was an order of magnitude greater than the expected value. The valve was satisfactorily tested per 73ST-2XI01, "Section XI Valve Stroke Timing and Position Indication Verification - Mode 1 through 4 Steam Generator Number 1 Containment Isolation Valves," and declared operable. The inspector concluded that the licensee's operability determination was appropriate based on satisfactory testing of the valve.

On September 30, 1993, the inspector observed electricians remove the coil. The terminal block marker and wire identification tags were blackened from the heat caused by the high resistance. The electricians were unable to identify the wires and had to use system prints to identify and temporarily mark the wires prior to removal. The inspector concluded that the workers were thorough and that the maintenance was appropriately conducted. The licensee initiated Condition Report/Disposition Request (CRDR) 2-3-0563 to perform a root cause of failure analysis of the solenoid coil. The inspector will review the results of the CRDR as part of Followup Item 50-528/93-40-03.

Unit 3

- Fuel building essential HVAC maintenance

On October 4, 1993, the inspector observed the replacement of a valve actuator in the fuel building "B" train essential air filtration unit (AFU). The inspector noted that the workers were aware of their radiological working conditions and made efforts to minimize their exposure. The inspector also noted effective interaction between the maintenance group and operations to minimize the effect of the maintenance on the filtration systems operability. The inspector reviewed Work Order 631913 and noted that the instructions appeared to be detailed and thorough. However, the inspector also noted several minor errors recorded in the work order. The inspector discussed these errors with the worker and supervisor. These errors were corrected. The inspector concluded that these errors did not affect quality and that the work was performed adequately.

No violations of NRC requirements or deviations were identified.

6. Local Leak Rate Test (LLRT) Valve Failure - Unit 1 (61726 and 92701)

On October 19, 1993, the inspector observed the "as left" LLRT for penetration 26, the shutdown cooling (SDC) "B" train containment penetration. The test was performed using surveillance test procedure 73ST-1CL01, "Containment Leakage Type 'B' and 'C' Testing," which tested the SDC outside containment isolation valves, SIA-UV-656 and SIA-HV-690. The leak rate for SIA-UV-656 was determined to be 19,600 standard cubic centimeters per minute (sccm), which exceeded the test acceptance criteria of 4,000 sccm. The failure was noted in the test log. The inspector concluded that the technicians were thorough and appropriately documented the failure of SIA-UV-656.

The inspector discussed the planned corrective action for the excessive leakage with the test engineers. The licensee documented the problem using a deficiency work order and planned to repair the problem during the next refueling outage.

The licensee stated the following reasons for deferring corrective maintenance of the valve:

- The 10 CFR Part 50, Appendix J, limit for type B and C tests (0.60 La) was met by a significant margin. The licensee estimated the total leak rate would be only about 20% of the limit.

- The "as found" leak rate for the valve was about the same during the previous outage. The motor operator was adjusted to increase the seating force and the valve passed the "as left" LLRT during the previous outage. Therefore, the licensee did not believe the leak rate would substantially increase.

- The SDC system is normally isolated at power with both the inside and outside containment isolation valves shut. To have a leak through SIA-UV-656, a leak path from the containment atmosphere would have to exist from upstream of the inside isolation valve and the inside isolation valve would have to fail. This section of piping would normally be filled with water and the inside containment isolation valve, SIA-UV-654, had consistently passed its LLRT.

- SIA-UV-656 passed Section XI valve stroke testing and motor operated valve testing.

The inspector noted that the regulatory requirements of 10 CFR Part 50, Appendix J, limited only the total leakage and there was not a limit on individual penetrations. The inspector concluded that the justification for deferring the maintenance on SIA-656 was reasonable and did not adversely impact the safety of the plant. The inspector also concluded that the requirements of ASME Section XI, 10 CFR Part 50 (Appendix J), and the licensee's procedure were properly met.

No violations of NRC requirements or deviations were identified.

7. Fuel Pin Damage and Debris in the Reactor Vessel - Unit 1 (62703 and 71707)

During the period from October 7 through October 16, 1993, the licensee replaced two damaged fuel pins and found seven pieces of debris in the reactor vessel. The inspector observed the licensee's corrective actions and evaluation of the safety significance of these events.

On October 7, 1993, the licensee was reconstituting fuel assembly P1F415 to remove a defective fuel pin. There were a total of eleven fuel pin failures identified during ultrasonic testing of fuel assemblies during core off-load. The licensee had previously predicted eight fuel pin failures based on primary chemistry information during cycle 4. As part of the fuel reliability program, the damaged fuel pin was to be removed and a stainless steel "dummy" pin installed. Prior to removing the pin, workers noted that the cladding was broken the entire circumference of the pin about thirty inches from the top of the pin. Workers removed the two pieces of the pin and placed them in a storage container located in the spent fuel pool. In order to remove the bottom part of the broken pin, eleven adjacent pins were removed and inspected for damage. One pin had a significant debris scar and was also replaced with a dummy pin. Two days later another fuel pin broke after it was removed from fuel assembly P2E107. The pin broke into two pieces while it was being lowered in the storage container. All of the pieces landed in the storage container. The inspector concluded that the damaged pins were safely stored and that the fuel reconstitution was appropriately conducted.

On October 9, 1993, during an inspection of the reactor vessel for debris, a small piece of metal (approximately 1/16 by 2 inches) was found on the core plate in the grid location for fuel assembly P2E107. On October 10, 1993, another piece of debris was found on the core plate (the fuel assembly for this grid location was not damaged). Both pieces of debris were removed using a vacuum cleaner. On October 14, 1993, during reloading of fuel assemblies, workers noticed a small piece of debris between core grid locations H-12 and H-13. A 1/16" triangular shaped piece of debris was found on the grid strap that appeared to be a piece of a weld or cladding. When the piece was being inspected, it was knocked off the grid strap and floated into the bottom of the core. There were no damaged fuel pins in the same location. The inspector concluded that the attentiveness of workers in the field was good and that these problems were quickly communicated to management.

The licensee subsequently conducted a meeting to determine the potential damage that could be caused by the debris. Based on analyses of previous debris in the core and studies by Combustion Engineering (CE) the following were determined:

- The lower end fitting of the fuel assembly has 0.4 square inch coolant flow holes. Pieces of debris larger than this (approximately 1/2 inch in diameter) would not be able to pass through the fuel and would probably just stay in the bottom of the reactor vessel.

- Pieces smaller than 0.4 square inches that are symmetrical in shape would probably flow through the fuel and not get caught on the grid straps. They would most likely be removed by the purification system.

- CE conducted actual flow tests and found that the worst type of debris was wire shaped because it could get caught on the fuel assembly grid straps. The pieces could then cause fretting of the fuel pins due to flow vibrations. The analysis determined that a maximum of four pins could be damaged by a single piece of wire debris.

- Pieces of debris that fall into the core cannot physically get into the control element assemblies (CEAs). The potential for damage to the CEAs is only if the debris is left in the top of the core where it can get caught in the CEA guide tubes.

The inspector concluded that the licensee thoroughly evaluated the consequences of having this type and size debris in the reactor vessel and that the potential damage to the fuel was bounded by the safety analysis.

On October 16, 1993, a piece of debris was identified in the bottom of fuel assembly P1F413. The debris was approximately 5/8" by 3/8" and was identified by a camera that was installed in the fuel transfer canal to inspect the bottom of all the fuel assemblies during core reload. A dummy assembly was loaded into the core and the fuel assembly was returned to the spent fuel pool. The debris was not located and since the debris may have moved up into the fuel assembly, the licensee decided to recage the assembly (see Paragraph 8). The inspector concluded that the installation of the camera in the fuel canal was prudent and led to identifying this piece of debris. The inspector also concluded that the decision to recage the assembly was conservative and displayed an emphasis on safety.

Also on October 16, 1993, some debris was found on the reactor vessel flange (two pieces of wire and a small washer). The pieces were removed and a complete inspection of the refueling area was conducted. The licensee did not find any more debris. Condition Report/Disposition Request (CRDR) 1-3-0565 was written to document the problem; however, the CRDR did not address the safety significance of these objects being in the core had they not been retrieved. The inspector requested that the licensee evaluate the potential damage from these pieces of debris, particularly if they remained on top of the fuel and could impact operation of the CEAs. An analysis was performed which included all seven pieces of debris that were found during the outage. The licensee concluded that the debris could not cause significant damage to the fuel or other reactor components. The licensee believed that CEA operation would not be impacted because a full core scan was performed with an underwater camera to ensure that the CEA guide tubes were clear. Also, the CEAs were lowered into the fuel with no interference noted and rod testing would be performed prior to power operation. Based on these facts, the licensee believed that any problem with CEA operation would be self-revealing prior to reactor startup. The inspector concluded that the licensee's evaluation adequately addressed the concerns of assuring proper CEA operation.

No violations of NRC requirements or deviations were identified.

8. Fuel Assembly Recaging - Unit 1 (62703)

On October 20, 1993, the inspector observed portions of the recaging of fuel assembly P1F413 due to a piece of debris that was found in the bottom of the assembly (see Paragraph 7). The evolution was conducted using procedure 78CP-9FH06, "Fuel Assembly Rod Removal, Transfer, and Insertion," and involved transferring the fuel pins from the existing fuel assembly (P1F413) to a new grid cage assembly (PXXU03).

The inspector determined that two fuel pins were removed from the existing fuel assembly and inserted into the wrong locations in the new grid assembly. This condition was initially identified by the Quality Control (QC) inspector and Combustion Engineering (CE) supervisor during a required inspection of the assemblies. This inspection was performed by examining the new grid cage to ensure that 50% stainless steel pins and 50% transferred fuel pins were present in the new assembly and that the remaining fuel pins in the old grid cage were arranged in a checker board pattern (every other fuel pin removed).

The inspector observed the workers remove the incorrect fuel pins and insert the correct fuel pins into the new assembly. The inspector concluded that the pins were appropriately identified by serial number and were left in their correct positions. The inspector also noted that there were good preventive measures in the procedure to identify these types of errors and that the workers promptly identified the problem.

The inspector questioned the QC inspector and CE supervisor concerning the level of confidence that a similar error could not happen later in the evolution. The inspector was informed that the pin pulling tool had one of the four collection collar fingers bent at an angle that may have resulted in the tool over reaching and latching the incorrect pin. The pin pulling tool was immediately repaired and the decision was made to conduct frequent inspections of the tool during the rest of the evolution. Additionally, the inspector noted that after the 50% point all adjacent locations to a target pin would be empty and that it was unlikely that the tool could over reach beyond one location. The inspector concluded that the immediate corrective actions were appropriate and that it was highly unlikely that the fuel pins could be incorrectly inserted into the new assembly and remain undetected.

No violations of NRC requirements or deviations were identified.

9. Operability Determination of Shutdown Cooling (SDC) Heat Exchanger (HX) Isolation Valves - Unit 1 (62703 and 71707)

On October 6, 1993, the inspector observed portions of a motor-operated valve test (39TI-9ZZ03, "MOV Dynamic Diagnostic Testing of the Low Pressure Safety Injection (LPSI) Valves Train A"). The inspector noted that during the performance of the test, the SDC HX isolation valve (SIA-HV-657), would not open past 10%. Operators manually opened SIA-HV-657 to achieve the required conditions for the test. The problem with SIA-HV-657 was documented in the test exception log and a work order was written to check the valve. The inspector concluded that these actions were appropriate.

The inspector noted that both SIA-HV-657 and the "B" train valve, SIB-HV-658, were not able to consistently open or shut under design basis conditions. Based on this information, the inspector questioned the operability of the SDC system. The shift supervisor stated that Appendix E of procedure 41OP-1SI01, "Shutdown Cooling Initiation," addressed the problem with SIA-HV-657 and SIB-HV-658 not operating with a high differential pressure (ΔP) and outlined contingencies to open or shut the valve. Based on these procedures and the fact that the valves operated satisfactory with normal SDC flow and ΔP, the shift supervisor determined that the valves and the SDC system were operable. The inspector reviewed the procedures and determined that there were appropriate contingencies to properly operate SIA-HV-657 and SIB-HV-658.

The inspector discussed the design basis for SIA-HV-657 and SIB-HV-658 with valve services engineers. The inspector determined that the valves were designed to perform as required in the operating procedure. The worse case ΔP across SIA-HV-657 and SIB-HV-658 would be from the shut off head of the containment spray (CS) pump. The inspector determined that the SDC HX bypass valves, SIA-HV-306 and SIB-HV-307, were primarily used to throttle flow before SIA-HV-657 and SIB-HV-658 would be opened. As long as the bypass valves functioned properly under full flow conditions, SIA-HV-657 and SIB-HV-658 would not have to operate against the shut off head of the CS pump. The inspector determined that SIA-HV-306 and SIB-HV-307 consistently operated satisfactorily under full flow conditions. Additionally, during a postulated loss of coolant accident at power, SIA-HV-657 and SIB-HV-658 are shut and the safety injection flow path is through SIA-HV-306 and SIB-HV-307 (which are required to be open). The inspector concluded that the condition was adequately analyzed and that the operability determination was appropriate. The inspector also noted that the licensee was pursuing actions to correct the design deficiencies of SIA-HV-657 and SIB-HV-658 and that these actions were appropriately documented.

No violations of NRC requirements or deviations were identified.

10. Low Pressure Safety Injection (LPSI) Pump Breaker Failure to Close - Unit 1 (71707 and 92701)

On October 23, 1993, the Unit 1 LPSI "A" pump motor breaker failed to remain closed when operators attempted to start the pump. The pump was started to lower refueling water level after testing. Train "B" of shutdown cooling was in operation. The LPSI breaker is a General Electric (GE) Magne-blast, vertical-lift, horizontal-drawout breaker with a rating of 1200 amperes and 4160 volts. When the control room handswitch was taken to start, a red, breaker-closed indication was noted on the control board, immediately followed by a green, breaker-open indication. The pump motor amperes pegged high as expected during a normal start sequence and then decreased to zero concurrent with the green, breaker-open indication. The breaker was immediately inspected and no problems were noted. Additionally, there were no targets or flags set at the breaker. The licensee subsequently shut the breaker from the control room and the breaker remained closed.

On October 24, 1993, the licensee removed the LPSI "A" breaker and installed a spare breaker. Initial troubleshooting revealed that the closing mechanism was not setting properly. The operating mechanisms used on this breaker include a spring, called a prop spring, that is used to reset the mechanism prop to a position under the prop pin at the end of a closing operation. The prop spring keeps the prop pin in a position that locks the breaker in the closed position. The licensee found that when the breaker was fast closed (using the closing springs) the breaker would close and the pin would rotate to the correct position. However, the pin would immediately slip off the prop opening the breaker. This would not happen when the breaker was manually slow closed.

Further troubleshooting revealed that the prop spring mounting bracket was loose. Technicians tightened the bracket and subsequently tested the breaker. The breaker stayed closed, however, there was not enough clearance between the prop pin and the end of the prop. Without this clearance, the breaker may have opened if the breaker was subjected to a shock or vibration. A new prop spring was installed and subsequent tests resulted in the same problem with the prop pin clearance. The licensee contacted GE and was continuing troubleshooting efforts at the end of the inspection period.

The inspector concluded that there was an appropriate level of management concern regarding the potential safety implications of the LPSI breaker failure. The initial troubleshooting efforts and the decision to replace the breaker were appropriate. The inspector will review the results of the licensee's evaluation of the failure in Condition Report/Disposition Request 1-3-0599 (Followup Item 50-528/93-43-02).

No violations of NRC requirements or deviations were identified.

11. Steam Generator Inspections - Units 1 and 3 (61726, 71707, and 92703)

During this inspection period, the licensee performed inspections of the steam generator (SG) tubes in Unit 1 and reviewed data from the inspections performed in Unit 3 during the last refueling outage (3R3 - October 1992).

The licensee did not find mid-span axial indications in Unit 1 steam generators, as had been found in Unit 2 following the SG tube rupture event on March 14, 1993 (see NRC Inspection Report 50-529/93-14). The significant indications and defects found in Unit 1 can be generally characterized as circumferential cracks at the tubesheet transition area (both inside and outside diameter cracks) and tubesheet axial cracks. The licensee performed sludge lancing to improve the chemical environment at the tubesheet, and is planning to implement a significant reactor coolant system hot leg temperature reduction to reduce susceptibility to primary water stress cracking corrosion in all units. The licensee intends to plug all defective tubes and all tubes with axial indications.

In reviewing Unit 3 tube inspection data taken during the previous outage (3R3), the licensee identified two SG tubes exhibiting signs of possible axial indications in the upper region of the tube bundle in SG31. The indications were not definitely classified as axial cracks because the type of probe used in the inspection was inadequate to make such a determination. A Confirmatory Action Letter was issued on October 4, 1993, confirming the licensee's commitments to shutdown Unit 3 for SG tube inspections after the Unit 1 refueling outage (but not later than November 26, 1993), to complete review of the 3R3 tube inspection data, to complete planned inspections of the Unit 1 tubes, to implement changes to emergency operating procedures, to operate Unit 3 at no more than 85% power, and to reduce reactor coolant system cold leg temperature (T-cold) to 555 °F.

The licensee has implemented the T-cold reductions in Unit 2 (on October 15, 1993) and Unit 3 (on October 26, 1993), completed the SG inspections in Unit 1, and completed the review of Unit 3 3R3 data. Four other potential axial indications were identified in the review of the 3R3 data and were discussed with the NRC in conference calls.

The inspector concluded that the licensee was proactive in reviewing old data and identifying possible defects, and that the licensee's actions, documented in the Confirmatory Action Letter, were appropriate.

No violations of NRC requirements or deviations were identified.

12. Set Pressure Verification Testing on SGA-PSV-316 - Unit 2 (62703)

On September 24, 1993, the inspector observed the performance of surveillance test procedure (ST), 73ST-9ZZ20, "Set Pressure Verification," on relief valve SGA-PSV-316. SGA-PSV-316 is the pressure relief valve on the nitrogen accumulator system for atmospheric dump valve number 184. This was a reworked valve from the warehouse that was being tested prior to being placed into service. The inspector identified that the second lift test results were marked as satisfactory with a lift pressure of 724 psid. The procedure acceptance criteria stated the lift pressure must fall between ±3% of the set pressure, which was 700 psid for this valve. The inspector questioned the maintenance technician about the test lift being marked satisfactory when it was outside the 700 ± 21 psid criterion. The technician referred to the Station Information Management System (SIMS) database table which is referenced in the procedure as a source for identifying set pressures and tolerances. The SIMS database stated the set pressure for this valve was 700 ± 24 psid. The Quality Control inspector and the maintenance foreman had identified this discrepancy earlier and the maintenance foreman had contacted the system engineer for clarification. The system engineer was unsure of the correct acceptance criteria and stated they would get back to the foreman with the correct acceptance criteria.

The foreman decided to continue testing without first resolving the discrepancy with the acceptance criteria. This decision was based, in part, on the fact that the valve was being tested in the shop and would not be installed until the discrepancy was resolved and after the first test lift the valve displayed excessive seat leakage and would most likely not pass the ST. However, the mechanic continued to treat the ST as a valid test. The inspector and licensee management concluded that the technician and foreman actions did not meet management's expectations for performing surveillance tests and was considered a weakness. The inspector noted that appropriate actions were taken to initiate a revision to the procedure to include the set pressure and tolerance for each applicable valve within the procedure.

The technicians completed testing the valve and all subsequent "lifts" exceeded the acceptance criteria. Because the valve failed its acceptance test, another reworked valve from the warehouse was obtained and the Certificate of Compliance reviewed. This review is covered under procedure 73ST-9ZZ20, "Set Pressure Verification," which states that the ASME Section XI Pump and Valve Engineer/designee is responsible for completing the applicable procedure sections for valves tested off-site. On September 24, 1993, a Certificate of Compliance review was performed by a mechanical maintenance technician and the second valve was placed in service.

The inspector determined that the safety significance of the ASME Section XI engineer not completing the Certificate of Compliance review or designating the authority to the maintenance technician was low, because the actions were primarily administrative and because the technician sought assistance when he was unsure of how to proceed. The inspector concluded that the completion of the surveillance test by the maintenance technician instead of the ASME Section XI engineer was a violation of Technical Specification 6.8.1 for failure to follow procedures. In addition, the licensee initiated appropriate corrective actions to prevent this from recurring. This violation is not being cited because the criteria specified in Section VII.B of the Enforcement Policy were satisfied (NCV 50-529/93-43-03).

The inspector also questioned the operability determination of using a review of the Certificate of Compliance without confirmatory testing for placing the second valve in service after the first valve had failed to pass the ASME requirement to lift three consecutive times. After extensive discussions with management, the inspector concluded that the lift testing did not need to be performed prior to placing the relief valve into service because the testing had been done at the vendor's facility and that past testing done on-site had not shown a problem in meeting lift setpoints.

One non-cited violation of NRC requirements was identified.

13. Reactor Trip - Unit 2 (92700 and 93702)

Unit 2 automatically tripped on low steam generator level from 85% reactor power at approximately 8:08 a.m. (MST) on November 1, 1993, following the automatic tripping of both turbine-driven main feedwater pumps. All plant systems responded as expected following the event, and the operators promptly stabilized the unit in Mode 3.

The root cause of failure of the trip was determined to be faulty secondary contacts in the potential transformer drawer for a 4160 volt non-safety related bus (NBN-S01), which supplies power to two condensate pumps and a heater drain pump. Multiple trouble alarms on the bus were received in the control room for about five minutes prior to the trip, apparently due to sensed voltage being at the low voltage setpoint. The trouble alarms were consistent with secondary contact problems. With sensed low voltage from the secondary contacts, the bus shed its loads at 8:07 a.m. as expected, leading to the loss of two condensate pumps and a heater drain pump. This resulted in the loss of both main feedwater pumps and a reactor power cutback. A reactor trip occurred at 8:08 a.m. Auxiliary feedwater actuation signals (AFAS1 and AFAS2) were received due to low steam generator water level, causing both essential feedwater pumps to start and both emergency diesel generators to start (but not automatically load). Operators successfully stabilized the unit in Mode 3.

Upon restoring the auxiliary feedwater system, the steam supply valve from steam generator number 2 to the turbine-driven auxiliary feedwater pump (valve 2SGA-UV-0138) would not fully close using the motor operator. Operators used the manual handwheel to close the valve. Subsequent evaluation revealed that the torque switch was broken so that the motor stopped when the torque switch cutout cleared, leaving the valve about 95% open. The torque switch was of an old style, and was replaced with a new one of a more substantial design. The valve was declared operable after appropriate retests. The inspectors will review the licensee's evaluation of the root cause of failure of the torque switch in a future inspection (Followup Item 50-529/93-43-04).

The inspector observed operator and management response to the event, and concluded that the licensee's response was adequate and appropriate, and that control room communications were effective. The inspector noted that the licensee determined that no primary-to-secondary leakage was detected during or following the event.

No violations of NRC requirements or deviations were identified.

14. Simulator Scenario Observations - Unit 3 (41500)

On October 21, 1993, the inspector observed a Unit 3 evaluated simulator scenario. The scenario was a combination of a reactor trip, an anticipated transient without a scram (ATWS), and a steam generator tube rupture event. The crew being evaluated demonstrated excellent command and control and good communications. The control room supervisor (CRS) held several short control room briefs to ensure that the crew remained informed of the current plant conditions and mitigation efforts. The CRS ensured that all crew members heard these briefs by announcing the brief and then waiting until he had the crew's attention prior to starting the brief. Additionally, the auxiliary operators were informed of the plant status periodically by radio. The operators demonstrated good communications and awareness of plant response. For example, the operators informed each other prior to taking actions that would cause an alarm.

The crew recognized and mitigated most aspects of the scenario quickly. Although the crew recognized and took proper actions for a steam generator tube rupture, they did identify indications of a possible rupture seven minutes earlier. These indications included the shift supervisor noting that the pressurizer level was not rising as fast as he expected. The CRS stated that they had cooled down rapidly to regain sub-cooling margin and that "shrink" may have slowed the level increase. The SS acknowledge the explanation but was still concerned. When the steam generator blowdown line monitor alarmed and the condenser vacuum gland exhaust monitor revealed an increasing trend, the CRS briefed the crew that they had a possible primary to secondary leak. The inspector concluded that seven minutes was not excessive and did not affect the actions taken to ensure plant safety.

The training staff noted that the cooldown rate to regain sub-cooling margin, approximately 40 °F in 10 minutes, was excessive and that plant conditions did not warrant this high rate. The guidance on cooldown was to establish and maintain a rate equivalent to approximately 100 °F per hour unless conditions or EOPs required a faster rate.

The inspector concluded that the scenario adequately challenged the capabilities of the crew. Additionally, the crew demonstrated excellent command and control and good communications, and quickly mitigated most aspects of the scenario, effectively ensuring plant safety.

No violations of NRC requirements or deviations were identified.

agreed with the apparent cause and that appropriate corrective actions were being taken to prevent recurrence. The inspector concluded that the identification of this deficiency by the fire protection personnel was commendable and displayed strong ownership for their responsibilities within the DAWPS facility.

Overall, the inspector concluded the audit was of sufficient depth and breadth and identified and followed through with meaningful observations and deficiencies.

b. Audit Report 93-009, "Technical Specifications"

The inspector reviewed licensee's QA audit report 93-009, "Technical Specification." The audit revealed numerous problems in the surveillance testing program and concluded that the surveillance testing program has not been established in such a manner as to ensure all Technical Specification requirements are met on a consistent basis. The audit also identified continuing weaknesses in procedure compliance and programmatic controls not being clearly defined.

In particular, the audit noted that surveillance test procedure 43ST-3CH06, "Charging Pump Operability Test," was performed on one of the three pumps every 30 days on a rotating basis. Section 8.1 of the surveillance procedure was performed on check valve CHE-V435 every 90 days, concurrent with the testing of one of the three charging pumps. The operators performing the surveillance test did not have a method established to determine during which monthly charging pump surveillance test that the check valve test needed to be performed. As a result of the audit findings, the licensee decided to revise procedure 43ST-3CH06 to ensure that valve CHE-V435 was tested whenever a charging pump was tested.

The inspector concluded that the audit was an indepth and critical review of the performance of technical specification surveillances.

No violations of NRC requirements or deviations were identified.

17. Accountability Drill - Units 1, 2, and 3 (82301)

On September 27, 1993, the inspector observed a site accountability drill from the central alarm station. The drill started in Unit 3 with the declaration of a site area emergency (SAE) due to reactor coolant system leak rate greater than the normal makeup capability. The Unit 3 shift supervisor announced the SAE at 8:12 a.m. At 8:23 a.m., all the units ade appropriate announcements and the emergency coordinator (EC) called urity to commence assembly and accountability.

e start of the drill, there were 1064 people inside the protected PA). At 8:35 a.m., the security captain printed a report that 110 people that were not in designated assembly areas out of 490 ll in the PA. The designated assembly areas inside the PA were

agreed with the apparent cause and that appropriate corrective actions were being taken to prevent recurrence. The inspector concluded that the identification of this deficiency by the fire protection personnel was commendable and displayed strong ownership for their responsibilities within the DAWPS facility.

Overall, the inspector concluded the audit was of sufficient depth and breadth and identified and followed through with meaningful observations and deficiencies.

b. Audit Report 93-009, "Technical Specifications"

The inspector reviewed licensee's QA audit report 93-009, "Technical Specification." The audit revealed numerous problems in the surveillance testing program and concluded that the surveillance testing program has not been established in such a manner as to ensure all Technical Specification requirements are met on a consistent basis. The audit also identified continuing weaknesses in procedure compliance and programmatic controls not being clearly defined.

In particular, the audit noted that surveillance test procedure 43ST-3CH06, "Charging Pump Operability Test," was performed on one of the three pumps every 30 days on a rotating basis. Section 8.1 of the surveillance procedure was performed on check valve CHE-V435 every 90 days, concurrent with the testing of one of the three charging pumps. The operators performing the surveillance test did not have a method established to determine during which monthly charging pump surveillance test that the check valve test needed to be performed. As a result of the audit findings, the licensee decided to revise procedure 43ST-3CH06 to ensure that valve CHE-V435 was tested whenever a charging pump was tested.

The inspector concluded that the audit was an indepth and critical review of the performance of technical specification surveillances.

No violations of NRC requirements or deviations were identified.

17. Accountability Drill - Units 1, 2, and 3 (82301)

On September 27, 1993, the inspector observed a site accountability drill from the central alarm station. The drill started in Unit 3 with the declaration of a site area emergency (SAE) due to reactor coolant system leak rate greater than the normal makeup capability. The Unit 3 shift supervisor announced the SAE at 8:12 a.m. At 8:23 a.m., all the units made appropriate announcements and the emergency coordinator (EC) called security to commence assembly and accountability.

At the start of the drill, there were 1064 people inside the protected area (PA). At 8:35 a.m., the security captain printed a report that listed 110 people that were not in designated assembly areas out of 490 people still in the PA. The designated assembly areas inside the PA were

agreed with the apparent cause and that appropriate corrective actions were being taken to prevent recurrence. The inspector concluded that the identification of this deficiency by the fire protection personnel was commendable and displayed strong ownership for their responsibilities within the DAWPS facility.

Overall, the inspector concluded the audit was of sufficient depth and breadth and identified and followed through with meaningful observations and deficiencies.

b. Audit Report 93-009, "Technical Specifications"

The inspector reviewed licensee's QA audit report 93-009, "Technical Specification." The audit revealed numerous problems in the surveillance testing program and concluded that the surveillance testing program has not been established in such a manner as to ensure all Technical Specification requirements are met on a consistent basis. The audit also identified continuing weaknesses in procedure compliance and programmatic controls not being clearly defined.

In particular, the audit noted that surveillance test procedure 43ST-3CH06, "Charging Pump Operability Test," was performed on one of the three pumps every 30 days on a rotating basis. Section 8.1 of the surveillance procedure was performed on check valve CHE-V435 every 90 days, concurrent with the testing of one of the three charging pumps. The operators performing the surveillance test did not have a method established to determine during which monthly charging pump surveillance test that the check valve test needed to be performed. As a result of the audit findings, the licensee decided to revise procedure 43ST-3CH06 to ensure that valve CHE-V435 was tested whenever a charging pump was tested.

The inspector concluded that the audit was an indepth and critical review of the performance of technical specification surveillances.

No violations of NRC requirements or deviations were identified.

17. Accountability Drill - Units 1, 2, and 3 (82301)

On September 27, 1993, the inspector observed a site accountability drill from the central alarm station. The drill started in Unit 3 with the declaration of a site area emergency (SAE) due to reactor coolant system leak rate greater than the normal makeup capability. The Unit 3 shift supervisor announced the SAE at 8:12 a.m. At 8:23 a.m., all the units made appropriate announcements and the emergency coordinator (EC) called security to commence assembly and accountability.

At the start of the drill, there were 1064 people inside the protected area (PA). At 8:35 a.m., the security captain printed a report that listed 110 people that were not in designated assembly areas out of 490 people still in the PA. The designated assembly areas inside the PA were the control room, the operations support center, the technical support center (TSC), and inside containment for outage personnel. The list of 110 people was reduced to 22 by eliminating the security guards, fire protection personnel, and others who had been accounted for and were outside the designated areas. The security captain delivered the list of 22 people to the EC in the TSC at 8:39 a.m., 16 minutes from the official start of accountability (the requirement is within 30 minutes).

The inspector concluded that the drill was significantly improved from the last drill conducted in May 1993. The licensee adequately demonstrated the ability to account for all personnel inside the PA within the 30 minute requirement. The inspector also concluded that there were several good initiatives implemented to improve the performance of the security organization. For example, software changes in the security computer allowed the officers to print a report that listed all personnel who were inside the PA and not in designated assembly areas. During the May 1993 drill, this had to be performed manually which caused a significant delay in the accountability process.

No violations of NRC requirements or deviations were identified.

18. Followup on Previously Identified Items - Units 1, 2, and 3 (92701 and 92702)

a. (Closed) Violation 50-528/93-11-09, Incomplete Work Order (WO) Closure - Unit 1

This item involved a WO being signed as complete without updating the valve designation list (VDL) required by procedure 30DP-9MP01, "Conduct of Maintenance." The licensee determined that the work group supervisor (WGS) assumed that the planner/coordinator would complete the step to update the VDL when the work package was returned to work control for closure. The WGS made this assumption based on an informal agreement between work control and the maintenance welding shop that the planner would complete the paperwork to initiate the change. This practice was not specified in the maintenance procedures in use at the time of this error (November, 1992). The licensee conducted a review of archived work orders for similar errors and did not identify any other cases of the WGS failing to initiate a change to the VDL. Additionally, active work orders were updated to clearly assign the responsibility of initiating the VDL change to the WGS. The inspector concluded that these actions were appropriate. This item is closed.

b. (Closed) Followup Item 528/93-11-12, Condition Report/Disposition Request (CRDR) Program Pockets of Resistance - Units 1, 2, and 3

This item was opened to review licensee actions related to a significant number of CRDRs either not being adequately evaluated or corrective actions not being implemented, with the problem being notably worse in a small number of licensee organizational units. In response to this issue, the licensee initiated CRDR 9-3-0276 to evaluate CRDR rejection rates and organizations responsible for significant numbers of rejected CRDRs.

Two licensee organizations, Quality Assurance (QA) and Station Operating Experience Department (SOED), reviewed a sample of CRDRs for quality of evaluations and completion of corrective actions. From this data, five departments (Security, Procurement Engineering, Nuclear Electrical Engineering, Nuclear I&C Engineering, and Fire Protection Support) were identified as having a high CRDR evaluation rejection rate (more than 1-in-6 rejection ratio and more than three rejections per quarter). Two other departments (Radiation Protection and Plant Engineering) were identified as having more than four CRDR evaluations rejected per quarter, though they did not have high rejection ratios.

The licensee determined that the root cause of many of the poor evaluations was a lack in investigative and root cause analysis skills. As a programmatic enhancement, the SOED now issues a "Human Performance Evaluation Aide" in CRDR evaluation packages to lead CRDR evaluators through effective causal factor analysis. Additionally, evaluators and supervisors in all departments were made aware of the high rejection rates, and the improper closure of CRDRs while corrective actions are incomplete, in a June 14, 1993, memorandum from the Vice President - Nuclear Production.

The licensee noted that evaluations improved somewhat between the first and second quarters of 1993. SOED engineers are being assigned to meet with managers of specific organizations to provide guidance on improving CRDR evaluations. SOED intends to reevaluate trends in CRDR evaluations following the third quarter.

The inspector concluded that the licensee's corrective actions were appropriate, and that continued monitoring of performance in this area by management and licensee oversight organizations was warranted. Based on this review, this item is closed.

c. <u>(Closed) Violation 50-528/93-26-01, Surveillance Test (ST) Documentation Improperly Completed - Unit 1</u>

This item involved several instances in Unit 1 of personnel not following the administrative controls for ST documentation. The specific examples involved not marking unsatisfactory steps in the procedure and making a test log entry to document the problem. The licensee had identified these same types of errors in two quality assurance audits and had outstanding corrective action documents to track the resolution of the issues. The licensee also identified that there was a misunderstanding among some operations and maintenance personnel that the requirements of procedure 73AC-9ZZ04, "Surveillance Testing," were not applicable to all portions of surveillance procedures. For example, some people thought the requirements for documentation were only applicable to technical specification acceptance criteria. Unit 1 management conducted several briefings and wrote a night order that emphasized the high level of documentation required for all portions of surveillance tests. The licensee also formed a cross-organizational ST program review focus group to improve the instructions for ST documentation. The procedure change was not completed at the end of this inspection period. However, the effectiveness of the changes will be evaluated during future routine inspection activities. The inspector concluded that management's expectations for ST documentation were clearly communicated to the workers (see Paragraph 3 for two examples of workers properly documenting ST anomalies) and that appropriate corrective actions were identified. This item is closed.

d. (Closed) Followup Item 50-529/90-28-02, Core Operating Limit Supervisory System (COLSS) Controls - Units 1, 2, and 3

This item addresses configuration control and quality classification of COLSS and COLSS databases, and was opened as the result of several configuration control errors with COLSS databases. The inspector also noted that another event occurred during the startup following the Cycle 5 refueling outage in Unit 2, in which three of the COLSS databases were found to contain Cycle 4 data. Evaluation of this recent event is being tracked by Followup Item 50-529/93-40-01.

Quality Classification

The inspector reviewed the licensee's COLSS Quality Classification/Determination, documented in a March 12, 1993, licensee memorandum. The licensee concluded that COLSS and associated databases, were appropriately classified as "Non-Quality Related" (NQR). Quality Deficiency Report (QDR) 91-0002 states that the basis for classification as NQR is that the software does not "initiate any direct safety-related function during an Anticipated Operational Occurrence or postulated accident," although the software poses a potential impact on the operation and functionality of the Quality Class "Q" software and data. The inspector determined that this classification was consistent with licensee procedures 60AC-0QQ09, "Classification of Activities," and 81AC-0CC06, "Classification of Structures, Systems, and Components."

The licensee's review addressed several questions related to COLSS function which could affect proper classification. While these were generally thorough, one relevant question was not addressed in either the memorandum or the QDR: Since COLSS calculates an Limiting Condition for Operation (LCO) (for power operating limit), should COLSS be classified as safety-related (i.e., "Q")? Technical Specifications 3.2.1.a and 3.2.4 require that the COLSS calculated core power be maintained less than or equal to the COLSS calculated power operating limit, based on linear heat rate and departure from nucleate boiling ratio (DNBR) respectively, when COLSS is in service. The licensee explained that numerous control room indications provide confirmation of reactor power level, and that any significant deviation between COLSS power and actual power would be obvious to operators. These indications include reactor coolant system temperature, secondary plant parameters, and nuclear instrumentation. The inspector also discussed potential failure modes of COLSS with the licensee, and concluded that there was not any apparent failure mode which could result in COLSS calculating a significantly errant power operating limit without operators recognizing the error before reactor power was changed to exceed any core limits.

The licensee developed significant controls for COLSS software, beyond those applied to most of the other NQR software, to ensure the configuration was accurate. Additionally, some of the elements of the Operations Quality Assurance Plan, such as review and control of configuration control procedures, are implemented for COLSS.

Configuration Control

The inspector reviewed QDR 91-0002, documenting the licensee's evaluation and corrective actions related to software configuration control. The controls for core protection calculator (CPC), control element assembly calculator (CEAC), and COLSS addressable constants appeared to be adequate.

The licensee-established controls for software differ for software of differing quality classifications and importance. CPC and CEAC software is classified "Q" and is rigidly controlled to include traceability, independent verification, and authorization for installation and use. COLSS is controlled by procedures 77DP-9ZZ02, "Process Computer Software Modification Control," 77DP-9ZZ03, Process Software Configuration Control," and 77DP-9ZZ04, "Process Computer Software Testing," which incorporate guide lines of IEEE 828-1983, "Standard for Software Configuration Management Plans," and INPO Good Practice 86-024, "Software Controls for Plant Computers." The inspector reviewed these governing procedures, and noted that the stated scope and intent of the procedures appeared to be appropriate.

The inspector also reviewed procedure 77DP-9RJ01, "PMS/COLSS Database Constants Revisions." This procedure specified controls for receiving, reviewing, documenting, implementing, testing, and installing COLSS database files. This procedure appeared to be adequate to ensure that the proper COLSS database information is installed.

The inspector noted that the licensee recently performed a Quality Audit (Audit 93-10) of Software Quality Assurance, identifying several significant deficiencies. The deficiencies included lack of procurement controls, control of superseded software inadequate to prevent inadvertent use, and some software not reviewed and approved as required by the design modification process. While the audit focused on radiation monitoring system software, the controls are similar or the same as those for COLSS. The inspector concluded that additional licensee corrective actions are necessary and are being tracked by the Quality Assurance division.

The inspector reviewed selected data from two COLSS databases in Unit 2 and verified that actual values stored in the computers matched the expected values controlled by the licensee. The inspector also discussed the current configuration control program with the licensee. The licensee stated that several changes were being planned, some as a result of Quality Audit 93-10.

Conclusion

The inspector concluded that the licensee's classification of COLSS as NQR was justified. The inspector further concluded that the licensee developed and implemented configuration controls for COLSS and other software that were generally adequate, and that the COLSS databases in Unit 2 were the expected values. However, significant deficiencies were identified by the licensee's Quality Assurance department, and a recent COLSS database configuration error was noted which indicate continued licensee attention to software configuration control is warranted. Based on the above review, this item is closed.

e. (Closed) Followup Item 50-529/92-27-02, Verification of Plant Records - Units 1, 2, and 3

This item was reopened in NRC Inspection Report 50-528/93-35 because NRC headquarters personnel were further evaluating similar issues nationwide. The NRC review was completed, resulting in the issuance of a Notice of Violation (Violation 50-528/93-43-05) on October 15, 1993, and in the issuance of Generic Letter 93-03. The violation did not require a response from the licensee. Based on this review, this item is closed.

f. (Closed) Violation 50-530/93-26-05, Inadequate 10 CFR Part 50.59 Screening - Unit 3

This item involved not performing a 10 CFR 50.59 screening for a procedure change to the emergency diesel generator periodic surveillance procedures. The licensee determined that the violation was due to an inadequate interface between the vendor document control and the procedure review and approval programs. In this case, the procedure change was exempt from a 50.59 screening because it was based on changes to the vendor technical manual (VTM) which was defined as a design output document. A 50.59 screening was not performed on the VTM because it did not involve a design change. The licensee revised procedure 87AC-0CC08, "Control of Vendor Documents," to include a requirement for a 50.59 screening of any vendor submittals that contain technical changes. The inspector reviewed the changes and concluded that they provided an added level of assurance that intent changes to procedures would have the proper 50.59 screening. This item is closed.

g. (Closed) Violation 50-530/93-26-07, Inadequate Testing of Steam Bypass Control System (SBCS) - Unit 3

This item involved the inadequate testing of a modification to the SBCS that resulted in the inadvertent opening of five steam bypass control valves in Unit 3. Specifically, the vendor designed SBCS modification and retest and the licensee's concurring design review did not consider the impact of the SBCS master controller switch in manual mode operation.

The licensee determined that there were several contributing factors that lead to this error. First, the design modification testing requirements are part of the overall retest process which involves several procedures among the various engineering organizations. The licensee committed to include all test development references/instructions for design modification in procedure 81DP-0CC23, "Inspection/Test Requirements," and remove similar references from other procedures. Second, site technical support engineering was not always involved in the development of retest specifications for non-quality related design changes. The licensee committed to revising design procedures to include site technical support engineering in the development of test specifications for design changes regardless of quality classification. Third, the preparation of design change packages did not include an review of existing engineering evaluation requests (EERs) that may be applicable to the change.

The licensee provided a recommendation to engineering personnel involved in design changes to include a review of EERs during the preparation of the design change packages. The licensee also committed to updating the SBCS Failure Modes and Effects Analysis to include all modes of operation. The inspector concluded that these commitments were appropriate and should improve the design testing and validation process. Based on this review, this item is closed.

One violation of NRC requirements was identified.

19. Review of Licensee Event Reports (LER) - Units 1 and 2 (90712)

The following LERs were closed based on in-office review.

Unit 1

93-007	Revision 02	Snubber Testing not in Accordance with Technical Specifications

Unit 2

93-001	Revision 02	Manual Reactor Trip Following a Steam Generator Tube Rupture
93-002	Revision 01	MSSV and PSV Setpoints out of Tolerance

No violations of NRC requirements or deviations were identified.

20. Exit Meeting (71707)

An exit meeting was held on November 4, 1993, with licensee management and resident inspectors during which the observations and conclusions in this report were discussed. The licensee had no additional comments to the inspectors' findings. The licensee did not identify as proprietary any materials provided to or reviewed by the inspectors during the inspection.