U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.: 50-528/91-26, 50-529/91-26, and 50-530/91-26

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 9012
Phoenix, AZ 85072-3999

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

Inspection Conducted: June 16 through July 27, 1991

Inspectors: D. Coe, Senior Resident Inspector
F. Ringwald, Resident Inspector
J. Sloan, Resident Inspector
J. Melfi, Resident Inspector, Trojan

Approved By: Howard J. Wong 8/23/91
H. J. Wong, Chief Date Signed
Reactor Projects Section

Inspection Summary

Inspection on June 16 through July 27, 1991 (Report Numbers 50-528/91-26 50-529/91-26, and 50-530/91-26)

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors, and one inspector from the Region V staff. Areas inspected included: previously identified items; review of plant activities; engineered safety feature system walkdown - Unit 1; surveillance testing - Units 1, 2, and 3; plant maintenance - Units 1, 2, and 3; failure of Core Operating Limits Supervisory System (COLSS) - Unit 1; waste gas valves not fully closed - Unit 1; cracked weld on High Pressure Safety Injection (HPSI) loop injection valve - Unit 1; Atmospheric Dump Valve (ADV) nitrogen supply regulator failure - Unit 1; control element drive mechanism (CEDM) fans and exhaust ducts - Unit 2; pressure relief valve leak rate & removal - Unit 3; Steam Bypass Control System (SBCS) in emergency off with only one electro-hydraulic control (EHC) pump - Unit 3; reactor cutback - Unit 3; inadvertent containment spray - Unit 3; Confirmatory Action Letter followup; personnel performance issues - Units 1, 2, and 3; Corrective Action Program Evaluation; and review of Licensee Event Reports - Units 1, 2, and 3.

During this inspection the following Inspection Procedures were utilized: 30702, 35702, 61726, 62703, 64704, 71707, 71710, 71711, 92700, 92701, 92703, 92720, and 93702.

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Results Of the 18 areas inspected, one violation was identified in Unit 1. The violation pertained to the failure of operators to properly set addressable constants during Core Protection Calculator surveillance testing. Two non-cited violations were noted (Units 1 and 2) and involved missing operator log entries for Technical Specifications action statement entries.

General Conclusions and Specific Findings

Significant Safety Matters	None
Summary of Violations	One Cited Violation (Unit 1), Two Non-cited Violations (Units 1 and 2).
Summary of Deviations	None
Open Items Summary	4 items closed, 1 item left open, and 6 new items opened.

Strengths Noted

Control Room Operators responded well to the inadvertent containment spray event in Unit 3 and the reactor cutback event in Unit 3.

Weaknesses Noted

Significant issues addressed in this report were primarily related to attention to detail associated with plant operations and maintenance. The most significant of these was installation of incorrect Core Protection Calculator constants in Unit 1 following testing. In addition, the licensee's management failure to make a timely declaration of an Unusual Event for RCS leakage rate above Technical Specifications is discussed in this report, but left unresolved pending further evaluation by Region V Emergency Planning personnel.

DETAILS

1. Persons Contacted

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

Arizona Public Service (APS)

R. Adney,	Plant Manager, Unit 3
*R. Badsgard,	Assistant Manager, Site Nuc. Eng. Nuclear Project
J. N. Bailey,	Vice President, Nuclear Safety & Licensing
*J. A. Bailey,	Director, Nuclear Engineering
*B. Ballard,	Director, Quality Assurance
D. Blackson,	Manager, Central Maintenance
T. Bradish,	Manager, Compliance
*P. Brandjes,	Manager, Corporate Assessment
P. Caudill,	Director, Site Services
L. Clyde,	Manager, Operations Unit 3
W. Conway,	Executive Vice President, Nuclear
E. Dotson,	Site Director, Engineering & Construction
*R. Flood,	Plant Manager, Unit 2
R. Fullmer,	Manager, Quality Audits and Monitoring
D. Gouge,	General Manager, Plant Support
P. Hughes,	General Manager, Site Radiation Protection
*W. Ide,	Plant Manager, Unit 1
*K. Johnson,	Supervisor, Systems Engineers
*S. Kanter,	Owner Services, Site Representative
F. Larkin,	Manager, Security
*J. Levine,	Vice President, Nuclear Power Production
D. Mauldin,	Site Manager, Maintenance
J. Minnicks,	Manager, Maintenance Unit 3
*G. Overbeck,	Site Director, Technical Support
*A. Ogurek,	Manager, Corporate Assessment
F. Riedel,	Manager, Operations Unit 1
*R. Rogalski,	Supervisor, Quality Audits and Monitoring
*R. Rouse,	Supervisor, Compliance
*C. Russo,	Manager, Quality Control
R. Schaller,	Assistant Plant Manager, Unit 1
*T. Schriver,	Assistant Plant Manager, Unit 2
*J. Scott,	Assistant Plant Manager, Unit 3
J. Scott,	Site General Manager, Chemistry
*G. Shanker,	Manager, Station Operations Experience Department
B. Webster,	Manager, Component Specialty Engineering

Other Personnel

A. Cordova,	Site Representative, Public Service of New Mexico
*J. Draper,	Site Representative, Southern California Edison
K. Hall,	Site Representative, El Paso Electric Company
*R. Henry,	Site Representative, Salt River Project

The inspectors also talked with other licensee and contractor personnel during the course of the inspection.

*Personnel in attendance at the Exit meeting held with the NRC Resident Inspectors on July 26, 1991.

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

a. Unit 1

1. (Closed) Followup Item (528/90-45-01): "Malfunction and Potential Loss of As-found Conditions of a Potter-Brumfield Relay" - Unit 1 (92701)

This item involved the failure of a Potter-Brumfield Model MDR 7061 relay to open. The inspector reviewed the root cause of failure Engineering Evaluation Request 90-SA-025. According to the Potter-Brumfield Quality Assurance Department, the relay failed due to contamination debris identified as glass filled diallyl phthalate in and around the contact area. This material is switch insulation used in this design of relay, slivers of which appear to have entered the relay housing during manufacture. APS System Engineering concluded that the improved Potter-Brumfield relays continue to have a low failure rate. Based on the inspector's review of licensee action, this item is closed.

2. (Closed) Enforcement Item (528/91-04-01): "Fire Extinguisher Not Inspected As Required" - Unit 1 (92702).

This item involved two instances where fire extinguishers were in use by continuous fire watches without the required monthly inspections. The licensee immediately inspected both extinguishers and found them acceptable for use. The licensee also identified 15 extinguishers which had not had annual inspections. Eight of these 15 were located, inspected, and found to be acceptable for use. The licensee issued a memo on April 10, 1991, to fire watch personnel directing them to check their issued extinguishers prior to field use. These instructions were incorporated into 14AC-0FP04, "Firewatch Duties." The inspector reviewed this procedure change and concluded that this guidance appears appropriate. This item is closed.

b. Unit 3

1. (Open) Enforcement Item (530/91-04-01): "Routine Assignment of Overtime Working Hours Greater Than Technical Specification (TS) Limitations" - Unit 3 (92702)

This item involved Unit 3 Radiation Protection (RP) Technicians working in excess of 72 hours per week in an apparent routine manner without individual evaluation and approval of the overtime being worked and without administrative exclusion of these individuals from performing Emergency Plan duties should they be required. The licensee stopped RP Technicians from working in excess of 72 hours per week on April 4, 1991, and committed to revising Administrative Control Procedure 03AC-0EM01, "Overtime Limitations," to specify the requirements for review and approval of overtime in excess of TS limitations prior to July 15, 1991. The inspector was unable to review this procedure revision because it was not complete as of July 22, 1991. On August 8, 1991 the licensee submitted a letter which advised the NRC of a change in the date for revision of the procedure to August 31, 1991. This item will remain open until the licensee completes the committed procedure revision.

c. Units 1, 2, and 3

1. (Closed) Followup Item (528/90-54-02): "Engineering Action Request (EAR) Tracking Deficiencies" - Units 1, 2, and 3 (92701)

This item involved concerns regarding an EAR which was tracking committed engineering work, but was not being tracked effectively by the Nuclear Engineering Department. The inspector expressed concern that there may be additional EARs which were not being effectively tracked. The licensee initiated Problem Resolution Sheet (PRS) 1613 in response to the inspector's concern; however, this PRS did not address the concern. In a letter dated June 21, 1991, the Director, Nuclear Engineering Department (NED), stated that the control desk, a more effective tracking mechanism, is now being used to track NED work. In addition, this letter stated that there "... are no other significant work items that are being tracked by an EAR." The inspector concluded that significant work items are no longer being tracked by EARs, but are instead tracked by other appropriate mechanisms.

Based on the above review, this item is closed.

2. (Closed) Followup Item (529/91-15-01): "Auxiliary Building Floor Drains" - Units 1, 2, and 3 (92701)

This item involves the assessment of issues related to auxiliary building floor drains, some of which were either plugged when they should have been unplugged and others which were unplugged when they should have been plugged.

As soon as the licensee determined the correct configuration of the drains, the appropriate plugs were installed where required and the other drains were cleared of obstructions.

The licensee evaluated the auxiliary building flooding analysis and determined that adequate drain capacity existed even with some of the drains plugged or covered with steel plates or plastic. The inspector reviewed the drawings which confirmed the licensee's conclusions.

The licensee identified a potential unmonitored release path through the Essential Cooling Water (EC) Heat Exchanger (HX) room alternate drains to the Control Building sumps. The licensee evaluated the system and concluded that this was not a viable liquid release pathway. The Control Building sumps are pumped to the oily waste separator, which are sampled weekly for gross beta activity. The water is then pumped to the retention basins and then is batch processed to the evaporation ponds. The licensee stated that the periodic sampling of the retention basins results in most, but not all, batches being sampled. These samples have not shown any unexpected activity. The licensee also evaluated the drains as a gaseous release pathway and concluded that this was not viable because the auxiliary building is at a negative pressure with respect to the control building and because the four-inch diameter drain pipe is insignificant. The inspector discussed these findings with Region V radiation protection inspectors and had no further questions or concerns related to potential release paths.

It was noted by the inspector that licensee actions to resolve the potential unmonitored release path took longer than expected. Although the licensee informed the inspector of the unmonitored release potential on May 31, 1991, in a meeting involving several licensee managers, the licensee took no further action to assess the significance of this release pathway or to determine if a release had actually occurred until June 18, 1991, despite several inquiries from the inspector in the interim. Licensee management stated that a communications breakdown had occurred due to the several issues involved and that the management expectation is that followup of such issues would occur in a much more timely fashion than it did in this instance.

The licensee did not determine the cause of loss of control over auxiliary building drains. However, it has established control over the normally plugged drains by means of signs at each drain to prevent inadvertent establishment of unmonitored release paths. Additionally, Engineering Evaluation Request (EER) 90-RD-13 was initiated to address controls over normally open drains. This EER is still open. The inspector noted that no actual flood control deficiencies or unmonitored releases were identified during this review, but encouraged the licensee to properly evaluate changes to the drain system in the future. The inspectors will monitor status control as part of routine inspection activities.

The inspector concluded that licensee actions upon identification of these deficiencies was appropriate. This item is closed.

3. Review of Plant Activities (71707 and 93702)

a. Unit 1

Unit 1 operated at essentially 100 percent power throughout this reporting period, with the exception of a 30-minute downpower to about 99 percent on June 20, 1991, due to the failure of the Core Operating Limits Supervisory System (COLSS), and an eight-hour downpower to about 80 percent on June 27, also due to a COLSS failure.

b. Unit 2

Unit 2 operated at essentially 100 percent power throughout this reporting period.

c. Unit 3

Unit 3 began this inspection period at 100% power. On June 19, 1991, the unit experienced an inadvertent containment spray actuation, manual reactor trip, manual reactor coolant pump trips, and natural circulation cooling as discussed in Paragraph 15 of this report. A notification of unusual event was declared and exited on June 19, 1991, as a result of the event. The unit proceeded to Mode 5 for troubleshooting and repair, then started up on June 22, 1991. The unit reached 100% power on June 23, 1991. On July 5, 1991, the unit experienced a reactor cutback as discussed in Paragraph 14 of this report. The unit returned to 100% power on July 7, 1991. Over the course of this inspection period, identified RCS leakage increased to more than one gallon per minute. On July 12, 1991, the unit corrected the leakage as discussed in Paragraph 12. However, failure to fully close a valve during restoration from this evolution resulted in unidentified RCS leakage of more than 1 gallon per minute. The unit ended the reporting period at 100% power.

d. Plant Tours

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

- Containment Building
- Auxiliary Building
- Control Complex Building
- Diesel Generator Building
- Radwaste Building
- Fuel Building
- Technical Support Center
- Turbine Building
- Yard Area and Perimeter

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.

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 (RCA), posting of radiation and high radiation areas, compliance with Radiation Exposure Permits (REP), personnel monitoring devices being properly worn, and personnel frisking practices.

No violations of NRC requirements or deviations were identified.

4. <u>Engineered Safety Feature System Walkdowns - Unit 1 (71710)</u>

Selected engineered safety feature systems (and systems important to safety) were walked down by the inspector to confirm that the systems were aligned in accordance with plant procedures.

During this inspection period the inspectors walked down accessible portions of the following system.

<u>Unit 1:</u>

Essential Cooling Water "B"

No violations of NRC requirements or deviations were identified.

5. <u>Surveillance Testing - Units 1, 2, and 3 (61726)</u>

a. Selected surveillance tests required to be performed by the Technical Specifications (TS) 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 TS; and 4) test results satisfied acceptance criteria or were properly dispositioned.

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

Unit 1 Procedure	Description
o 41ST-1SF01	CEA Operability Checks

Unit 2 Procedure	Description
o 36ST-2SE02	Excore Linear Monthly Calibration
o 36ST-2SE03	Excore Safety Linear Channel Quarterly Calibration

Unit 3 Procedure	Description
o 36ST-9SA01	ESFAS Train "A" Subgroup Relay Monthly Functional Test
o 73ST-9CL03	140 Foot Containment Access Leak Test
o 73ST-9ZZ20	ASME Section XI Offline Pressure Verification

On June 27, 1991, during an inspection of a portion of procedure 73ST-9CL03, the inspector noted that the instrumentation test rig used was not labeled, contained multiple instruments and valves, was not addressed in procedures, and contained a possible flowpath which would permit non-conservative surveillance results. Discussions

with Component and Specialty Engineering (C&SE) resulted in the licensee committing to writing a department procedure which documents proper use of this test rig. The inspector considered this to be appropriate.

No violations of NRC requirements or deviations were identified.

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

a. 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 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.

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

Unit 1
Description

- Steam Bypass Control Valve (SGV 1005) Positioner Calibration
- Essential Chiller "A" Refrigerant Distillation PM
- Essential Chiller "B" Shutdown Indications PM
- Fabricate and Install Reference Leg Tubing for Auxiliary Steam Pressure Gauge
- Quarterly Emergency Lighting PMs
- Decontaminate and Build Local Containment for HPSI Loop Injection Valves
- Test Westinghouse ARD Relays

On June 17, 1991, the inspector observed a technician in Unit 1 sign off a work step in Work Order 480490 prior to completion of the actions described in the step. The step required calibrating an instrument loop for Steam Bypass Control Valve SGN-UV-1005 per five data blocks, but the step was signed after only the first data block was complete. Several hours of additional work were required to complete the actions of the prematurely signed step. Subsequently, the work order step was fully completed. The licensee acknowledged that this was not consistent with management expectations.

Unit 2
Description

- Inspect CEDM Fan Exhaust Stacks
- Install CEDM Fan Exhaust Stack Restraining Cables
- Troubleshoot and Replace Motor for "A" Essential Spray Pond Pump
- Test Westinghouse ARD Relays

Unit 3
Description

- o QDN-N02 Operability Check PM
- o SG-PV-313B Grinding of Seal Weld
- o Steam Bypass Control Valve SGN 1007 Operability PM
- o CPC "C" Troubleshooting and Repair including retest using a portion of 77ST-9SB03 "CPC Channel 'C' Calibration"

On July 21, 1991, Unit 3 experienced an overvoltage condition on the A-C coincidence matrix power supply, PS-12, during a routine voltage measurement which resulted in the opening of the B and D reactor trip breakers. CRDR 3-1-0060 was initiated and troubleshooting was still in progress at the end of this inspection period. The results of this troubleshooting will be inspected during a subsequent inspection (Followup Item 530/91-26-01).

No violations of NRC requirements or deviations were identified.

7. Failure of Core Operating Limits Supervisory System (COLSS) - Unit 1 (71707)

On June 20, 1991, Unit 1 experienced a failure of COLSS on both the Core Monitoring Computer (CMC) and the Plant Computer (PC) when a computer technician made an incorrect entry on a computer console. The computer technician immediately rebooted the PC, and the control room operators began actions required by Technical Specification Action Statement (TSAS) 3.2.4.a. COLSS was running on the PC within 15 minutes, and the operators decided to hold the required power decrease in abeyance while COLSS was being verified to be functioning properly. Approximately 49 minutes after the initial failure, COLSS was declared in service and operators exited the TSAS.

The inspector questioned whether the operators' actions were consistent with the TSAS requirements. When COLSS is not in service, the TSAS requires the licensee within 15 minutes to initiate corrective action to increase the DNBR to within the limits and either a) restore the DNBR to within its limits within one hour, or b) reduce thermal power to less than or equal to 20 percent of rated thermal power within the next six hours. Licensee management determined that, since all indications were that COLSS was properly functioning, the operators acted properly in terminating the power decrease while the verification was in progress, but recognized that if the verification process demonstrated that COLSS was not functioning properly, the TSAS requirements would still have to be met. Licensee management stated that it would also be appropriate to pursue the action required in the TSAS during troubleshooting or repair efforts. The inspector concluded that the TSAS requirements had been met.

In reviewing this event, licensee management also stated that the TSAS for COLSS out of service shall be entered when the operator has knowledge that he cannot meet the requirements for any of the parameters monitored by COLSS as noted in the Technical Specifications. When the Unit is at

100 percent power, the operator knows that he cannot meet the requirements for DNBR margin per TSAS 3.2.4, and should enter the TSAS before commencing the confirmation surveillance test 72ST-1RX03, "DNBR/LHR/AZITILT/ASI With COLSS Out Of Service." Licensee management also stated that the 15 minutes allowed in TSAS 3.2.4 to commence action is a part of the one hour allowed to complete the action. Finally, licensee management stated that control room and/or shift supervisor log entries related to entry and exit into TSASs will be precisely documented as to the time and the specific action statement.

These policies were documented in a July 30, 1991 internal licensee memorandum to be reviewed by all licensed operators.

No violations of NRC requirements or deviations were identified.

8. Waste Gas Valves Not Fully Closed - Unit 1 (71707)

On July 12, 1991, while investigating the cause of an increasing trend on RU-12, the waste gas decay tank discharge monitor, Unit 1 operations personnel identified two valves which were not tightly shut following a planned discharge on July 4, 1991. The trend, which had been increasing upward since the July 4 discharge, was not noticed or acted upon until about July 12, even though no detectable activity should have been present following the discharge because the system was purged with nitrogen. While the successful methodical determination and correction of the problem are positive examples of personnel performance, the failure to recognize earlier that the discharge lineup was not secured during the many times RU-12 indications were read represents several missed opportunities. Additionally, personnel failed to initiate any corrective action documents regarding potential equipment deficiencies, personnel performance or procedural inadequacies.

The inspector noted similarities between this issue and the licensee's experience with CHN-VM-34 in Unit 3, described in Paragraph 12 of this report.

No violations of NRC requirements or deviations were identified.

9. Cracked Weld on High Pressure Safety Injection (HPSI) Loop Injection Valve - Unit 1 (92700)

On June 17, 1991, with Unit 1 operating at 100 percent power, the licensee discovered cracks in a tack weld securing the yoke to the bonnet on one of eight HPSI loop injection valves, 1SIA-UV-617. The cracks were found during a periodic inspection required by the disposition of Engineering Evaluation Request (EER) 89-SI-206, which resulted from the identification of a cracked retaining nut on the valve. The retaining nut is designed to prevent rotation between the valve yoke and bonnet, and the tack weld was intended to prevent motion between the yoke and bonnet so that the retaining nut would not loosen. The EER, in conjunction with EER 89-SI-21, determined that the tack weld (two 1/4-inch welds) had sufficient strength to perform the function of the cracked retaining nut, but required periodic inspection of the tack welds until the retaining nut was replaced.

Material Nonconformance Report (MNCR) 91-SI-1056 was initiated to document the condition. Procedure 60AC-0QQ01, "Control of Nonconforming Items," allows the licensee seven days to either repair the condition or issue a Conditional Release to justify continued reliance on the system until the condition is corrected. Based on discussions with the System Engineer (SE) and the Shift Supervisor and Shift Technical Advisor, operators relied on the initial operability determination throughout the seven days while engineering evaluation continued. When the MNCR final disposition (to rework the weld) was received on June 21, operators did not have or ask for a more current engineering assessment, based on the more complete evaluation of the weld, to be considered in an updated operability determination. Additionally, although the SE knew on June 18 that the MNCR would be dispositioned to rework the weld, work was not commenced until June 24, the last day of the seven days allowed by the procedure.

The inspector questioned the appropriateness of the manner in which the seven days was used in this case, because efforts to develop justification for a Conditional Release ceased when the final disposition was issued, and two additional days passed before the weld was repaired, while the valve was considered operable without technical justification.

Following the repair, engineering was able to verbally justify their conclusion that the crack would not prevent the valve from performing its design function, though this is not documented.

Based on the above, the inspector concluded that the licensee acted in accordance with its procedures although repairs could have been completed earlier. The inspector noted that the seven days allowed by the MNCR procedure should not be casually used, particularly when the justification for a Conditional Release is not apparent or available.

The licensee stated that the seven days is not intended to subvert the TSAS limitations. The Quality Control Manager agreed to review the MNCR procedure to determine if any clarifications are appropriate.

No violations of NRC requirements or deviations were identified.

10. Atmospheric Dump Valve (ADV) Nitrogen Supply Regulator Failure - Unit 1 (92700)

On June 22, 1991, ADV-184 (1SGA-HV-184) failed surveillance test 41ST-1SG05, "ADV Nitrogen Accumulator Drop Test," due to a failed nitrogen supply regulator, 1SGA-PCV-317. The regulator was found to have foreign material (a piece of metal) imbedded in its seat, preventing proper operation. The licensee initiated Engineering Evaluation Request (EER) 91-SG-134 to evaluate the Root Cause of Failure (RCF) and appropriate corrective actions. The licensee replaced the failed regulator and successfully completed the test and returned the ADV to service.

Past history with foreign material interfering with the functionality of the regulators led to Unit 1 Restart Item 664 being developed. Licensee commitments, documented in Inspection Report 50-528/90-23, Paragraph

9.a.2, were intended to prevent future problems in this regard. The inspector discussed the status of these commitments with the licensee and determined that they had been met. No problems had been observed during the quarterly regulator calibration checks. The licensee stated that a filter had been installed upstream of the accumulator in January 1991. The inspector noted that no system flushes or cleanliness checks have occurred since the filter was installed.

The inspector concluded that previous corrective actions appear to have been inadequate to maintain the cleanliness and operability of the safety-grade ADV nitrogen system. The inspector will review RCF EER 91-SG-134 upon completion (Inspector Followup Item 528/91-26-01).

No violations of NRC requirements or deviations were identified.

11. Control Element Drive Mechanism (CEDM) Fans and Exhaust Ducts - Unit 2 (62703, 92700, and 93702)

During an inspection on June 25, 1991, in Unit 2 at 100 percent power, the licensee identified that the exhaust ducts for CEDM fans "B" and "D" were missing several mounting bolts. The "D" duct had six of 16 bolts in place, and the "B" duct had only one of 16 bolts in place. The mechanics temporarily secured the ducts with nylon rope, two-ton rigging straps, and C-clamps. The NRC inspector conducted an inspection of the mounting condition and the temporary rigging.

The NRC inspector also observed the licensee's inspection of the equipment conditions and noted that the licensee's engineer did not check to see if the remaining bolts were tight, although later checks showed that those on the "D" were tight and the one on the "B" was loose. Also, while the engineer recognized that the C-clamps could vibrate off in a short time, no consideration was given to securing it so that it would not cause damage if they fell. The engineer appropriately determined that additional rigging was needed for the "D" duct, which was temporarily restrained with a 1/4 inch nylon rope. The "B" duct, which was rotated about five inches off center at the base, needed a strap around the base and tie-wraps through the empty bolt holes to help prevent further motion. The inspector discussed his concerns regarding the existing bolt tightness and the C-clamps with the engineer. The licensee noted that the C-clamps were to be removed as soon as the additional restraints were installed.

Unit 1 has also experienced bolting failures. On June 22, 1991, the "B" CEDM fan was found laying on the floor of its housing as a result of bolting failures. Mounting bolt failures were observed in all four fans in Unit 1 on January 19, 1987. On April 20, 1988, 13 of 16 stack bolts for the "A" CEDM fan were found broken due to cyclic fatigue. In December 1988, fans "B" and "D" simultaneously tripped on ground fault, resulting in excessive vibration and premature failure of the mounting bolts of the "B" fan.

While observing the installation of restraining cables in Unit 2, the inspector noted that the cables did not fit as planned. The licensee completed the installation by switching the cables, and using an extra

shackle on the shorter cable. When questioned, the HVAC Foreman stated that the finished cables were never measured to verify that they were the proper length. The inspector concluded the failure to verify cable lengths was not consistent with ALARA considerations.

The inspector noted that the Quality Control inspector in the field signed off the hold point asserting that the installation complied with the requirements of the Material Nonconformance Report (MNCR). Even though the QC inspector had noted this difference on the work order, the Quality Assurance Director later determined that the hold point should not have been signed without first receiving an engineering review of the revised configuration.

The inspector questioned the licensee regarding the decision to perform the generic measurements in Unit 1, which has a substantially higher containment gaseous activity than the other units. The HVAC supervisor indicated that they had not considered the ALARA aspects of this job and were focusing on finishing the job expeditiously. The inspector concluded that ALARA was not considered by the group responsible for the job. The Central Maintenance Manager responded by committing to establish some form of reminder of critical items to consider, including ALARA, when time sensitive jobs are being planned. At the exit meeting, the licensee also noted that taking measurements in Unit 1 avoided the potential of having to make additional entries at Unit 1 if the cable lengths were incorrect. The inspector finally concluded that this might have been appropriate justification had it been considered or discussed with the central maintenance HVAC group, and that ALARA needs to be a central planning aspect for all work in the radiologically controlled area.

Only one CEDM fan is required to be running to support plant power operations, so the failure of a fan or its mounting bolts is of minimal safety significance. However, failed stack bolts could possibly result in a CEDM exhaust stack falling and damaging other safety equipment. The stacks are about eight feet high and weigh about 1125 pounds. The licensee promptly installed temporary restraining cables in all three units to provide assurance that bolt failures would not likely result in damage to other equipment.

The licensee is conducting an investigation, Condition Report/Disposition Request (CRDR) 9-1-0024, to determine the root cause of these failures and to establish corrective actions. It is expected that the past failures of fan bolts and the previous corrective actions taken will be factored into the root cause evaluation. This CRDR will be reviewed by the inspector upon completion (Inspector Followup Item 529/91-26-01).

No violations of NRC requirements or deviations were identified.

12. Pressure Relief Valve Leak Rate & Removal - Unit 3 (61726)

Unit 3 experienced an increasing Reactor Coolant System (RCS) leak rate exceeding 3 gallons per minute which was identified to be coming from CH-PSV-865, the pressure relief valve associated with the Reactor Coolant Pump (RCP) seal injection heat exchanger. The heat exchanger was

designed to heat the seal injection water, but has never been needed and the auxiliary steam supply to this heat exchanger has been removed and blank flanged in all three units. CH-PSV-865 was designed to protect this heat exchanger and associated piping, but is no longer necessary. The decision was made to remove and blank flange this relief valve in Unit 3. This required stopping seal injection flow. The RCP technical manual acknowledges this as an acceptable abnormal mode of operation as long as cooling water is supplied to the seal coolers because the RCP auxiliary impeller and jet pump provide an alternate supply of seal injection. The technical manual further recommends that this not be a normal mode of operation because this flowpath bypasses the seal injection filters and can contaminate and possibly degrade the RCP seals.

On July 11, 1991, the inspector attended evolution and operator tailboards prior to the start of this evolution. The inspector noted that the procedure being used was a variance to the charging system normal operating procedure. The inspector noted that the variance existed in several variations and resulted in some confusion during the evolution tailboard meeting. The inspector also noted that this variance lacked the formal reviews required for formal plant procedures. As a result of discussions between NRC and licensee management, the licensee stopped the evolution after it had begun, but had not progressed to the point of stopping seal injection in order to evaluate if this variance met the requirements of ANSI Standard N18.7 and Regulatory Guide 1.33.

The inspector noted that the use of a Senior Reactor Operator (SRO) in the field to direct the evolution could confuse the command and control function between the field SRO and the shift supervisor in the control room. The Unit 3 Operations Manager stated that command and control were to remain with the shift supervisor and the senior reactor operator was to be the field communication and direction focal point. The Operations Manager also agreed to discuss this with the senior reactor operator to ensure that management expectations are clearly understood.

The inspector further noted that during the operations tailboard on July 11, 1991, the seal injection flow controller for RCP 1B had a burned out light bulb for the Auto mode indication and it was not corrected by the time the evolution was started. The inspector noted that this indication problem had the potential for confusing operators during this evolution since this controller was to be manipulated. The Operations Manager is evaluating this issue and stated that the management expectation is for operators to replace control board light bulbs when they are noted to have burned out.

On July 12, 1991, the inspector observed the licensee conduct this evolution from the control room using a temporary procedure which had all the required formal reviews and a Plant Review Board review. The licensee had two engineers monitor RCP seal performance who noted that the seal and seal injection parameters responded as expected. At the conclusion of the evolution the licensee noted that unidentified RCS leakage was 1.3 gallons per minute. The licensee promptly entered the Technical Specification Action Statement (TSAS) and conducted a search for the leakage. CH-VM-34, a drain valve on the seal injection heat exchanger, was identified to be not fully closed despite two auxiliary operators verifying it was closed during the evolution. The valve was then shut by turning the handwheel approximately one-half turn. This fully shut the valve, reduced unidentified RCS leakage to below one gallon per minute, and permitted the operators to exit the TSAS. The inspector concluded that the valve is either damaged or inappropriate for this application if during three attempts auxiliary operators incorrectly concluded that the valve was shut when it was not. The licensee initiated Engineering Evaluation Request 91-CH-085 to evaluate whether the valve is appropriate for that application.

The licensee considered the requirement to declare a Notification of Unusual Event (NUE) in emergency procedure EPIP-02, on July 12, 1991, based on the increased RCS leakage and decided to not declare an NUE after a conference call between the Vice President of Nuclear Production, the Manager of Compliance, the Director and Manager of Emergency Planning, and the Unit 3 Plant Manager. On July 15, 1991, the licensee reconsidered this decision and made the late NUE declaration. The inspector was concerned that despite getting the appropriate management personnel involved to evaluate the decision, the wrong decision was made on July 12, 1991. Condition Report/Desposition Report 3-1-0054 and Incident Investigation Report (IIR) 3-1-0054 were written to document the licensee's evaluation. This will remain an unresolved issue (530/91-26-02) to be reviewed during a subsequent inspection.

No violations of NRC requirements or deviations were identified.

13. <u>Steam Bypass Control System (SBCS) in Emergency Off With Only One Electro-Hydraulic Control (EHC) Pump - Unit 3 (71707)</u>

On July 24, 1991, Unit 3 placed the SBCS in emergency off for 23 minutes on one occasion and for approximately three hours on another occasion, both done while only one Electro-Hydraulic Control (EHC) pump was available. This reduced the margin to a turbine trip which, had it occurred under these conditions, would very likely have caused a reactor trip and the lifting of both primary and secondary relief valves. The SBCS was taken to emergency off while the licensee replaced and calibrated pressurizer pressure transmitter 100X which has a bias input into the SBCS control circuitry. Only one EHC pump was available because the other was out for elective corrective maintenance. The Operations Manager stated that these factors were carefully considered and a reactor operator was dedicated to monitoring plant conditions to take the SBCS out of emergency off should the need arise. The inspector questioned this since the SBCS operation would be unpredictable with the varying signals during the replacement and calibration from pressurizer pressure transmitter 100X. The inspector was not aware of any compelling reason why these work activities were done simultaneously other than the coincidence of scheduling. The inspector concluded that this reduced the risk margins unnecessarily. The Operations Manager agreed that these tasks did not have to occur simultaneously and is evaluating additional corrective action.

No violations of NRC requirements or deviations were identified.

14. <u>Reactor Cutback - Unit 3 (93702)</u>

On July 5, 1991, Unit 3 experience a reactor cutback resulting from a "B" main feed pump overspeed transient. This is the third instance of this type of event and the previous events are documented in Inspection Reports 530/91-04, Paragraph 13, and 530/90-39, Paragraph 3.c. The plant responded normally and was stabilized at 70 percent power. Troubleshooting from the previous two events did not clearly identify the cause and the plant started up from the recent outage with data recording equipment connected to the feed pump. The data was not collected during the July 5, 1991 event because electric power was not available. Another load on the same circuit caused the circuit breaker to trip and this was not detected until after the overspeed event. The inspector concluded that this represents unsuccessful corrective action implementation.

The inspector further noted that the Shift Technical Advisor's (STA) unfamiliarity with the differences between the units resulted in the Temporary Data Acquisition System (TDAS) data being unusable. The inspector further concluded that this represents incomplete STA training and inconsistent equipment between units. The licensee responded by issuing Night Orders to assure power to data recording equipment and to U-3 STAs regarding TDAS use. The licensee also trained all STAs on TDAS differences between the units. The licensee also modified TDAS in all units to automatically begin recording data upon any abnormal change in steam generator level.

The inspector noted that in each of the three feedwater pump trips, feedwater discharge pressure to the steam generators did not exceed the main feedwater pump high discharge pressure alarm setpoint of 1800 psig, which is less than feedwater piping design pressure of 1875 psig. Based on this, the inspector concluded that no challenges had occurred to the integrity of the feedwater piping.

No violations of NRC requirements or deviations were identified.

15. <u>Inadvertent Containment Spray - Unit 3 (93702)</u>

On June 18, 1991, Unit 3 experienced an inadvertent Containment Spray Actuation System (CSAS) initiation while at 100% power. The spray was secured by the control room operators after approximately one minute resulting in an estimated 5000 gallons of borated water discharged into containment. The operators followed their abnormal operating procedure 43AO-3ZZ30, "Inadvertent Containment Spray," which directed the operators to trip the reactor and all four reactor coolant pumps. The operators then stabilized the plant using their Reactor Trip (43RO-3ZZ01) and Loss of Forced Circulation (43RO-3ZZ04) recovery operations procedures. The inspector arrived in the control room shortly after the event, verified critical safety functions, assessed operator actions, and evaluated the preliminary information regarding the cause of the CSAS signal. The shift supervisor initially determined that a Notification of Unusual Event (NUE) was not required by the emergency plan. Senior management later decided that the plant conditions conservatively warranted an NUE and declared an NUE one hour and sixteen minutes following the event.

Within two and one half hours of the event initiation, both the licensee and the inspector made containment entries to evaluate the effect of the spray on critical plant components. After satisfactory megger tests and visual inspections of two Reactor Coolant Pumps (RCPs) the licensee started two RCPs restoring forced circulation. The licensee exited the NUE. following the restoration of forced circulation.

The licensee was performing surveillance test 36ST-9SB04, "PPS Functional Test - RPS/ESFAS Logic," testing CSAS when the event occurred. The cause of the event was later determined to be an incorrect test pushbutton assembly which created a relay race condition in the test circuitry. This condition has been present since the switch was replaced in 1987, prior to Unit 3 power operations. However, the relay race has apparently not resulted in an inadvertent initiation until this event. In 1987, the unit I&C technicians submitted Engineering Evaluation Request (EER) 87-SB-10 requesting engineering help in determining how to assemble this switch, but the switch was reassembled and installed several months before the EER was dispositioned. The EER response did not contain the proper sequence assembly instructions. Additionally, the EER was incomplete in that it did not address orientation of the switch components, only their sequence, and did not recognize that the drawing containing proper assembly instructions was not on site. The switch was installed in an incorrect orientation, although in the correct sequence, and was satisfactorily tested. The switch configuration was apparently never compared to the EER disposition. During troubleshooting for this event the orientation error was realized and the crucial drawing has been obtained. The EER was superseded with corrected and complete information.

As a result of this event the licensee performed a category two investigation in accordance with procedure 90AC-0IP01, "Incident Investigation for Category 1 and 2 Events." This investigation included a review of the San Onofre inadvertent containment spray event which occurred on November 20, 1990. The inspector noted that the APS investigation included an evaluation of each of the points of the staff position identified in the NRC Safety Evaluation performed by NRR dated February 5, 1991, as a result of the San Onofre event. The APS Incident Investigation Report (IIR) was completed on July 19, 1991, but was not available for review by the end of this reporting period. The inspector will review the completed IIR during a subsequent inspection. In addition, the licensee submitted a letter dated June 28, 1991 to NRC Region V describing the event and the evaluations of the effects of the spray on components inside containment. The licensee concluded there were no adverse effects from the spray. Additionally, NRC Region V has initiated a request for NRR to review the conditions under which RCP's should be stopped following an inadvertant containment spray event, to evaluate if any guidance to the licensee is appropriate (Followup Item 530/91-26-03).

The inspector concluded that the command and control and operator communication shortly after the event; the decisions to declare an NUE, make the early containment entry, proceed to Mode 5 for troubleshooting and repair; and the evaluation of potential problems resulting from the event appeared appropriate. Of concern is the fact that in 1987 the test pushbutton was assembled incorrectly despite the fact that the unit requested help yet received incorrect/incomplete information from engineering. The inspector viewed this as an example of poor engineering work. The licensee responded by committing to using this as an example of the type of problem that can result from inaccurate engineering work in future department training.

No violations of NRC requirements or deviations were identified.

16. Confirmatory Action Letter Followup - Units 1, 2, and 3 (92703)

Confirmatory Action Letters (CALs) were issued to the licensee on March 3 and 28, 1989, for problems that developed during plant transients. The problems related to control of the Atmospheric Dump Valves (ADVs), Emergency Lighting, and Relays in the electrical busses transfer systems. As a result of these problems, the licensee initiated a program to identify these items, and track and close out these items when the actions were taken. Over 800 items were identified.

The inspector sampled several of the closed and open items. The licensee informed the inspector that most of the items were closed, but several of the items that remained open were going to remain open past their current implementation dates. For example, the modification to the Sub-Synchronous Relay (SSR) for the fast bus transfer would not be implemented in Unit 3 until the next outage (1993). The inspector questioned this, and was informed that the SSRs were installed and working under a temporary modification, but would not be made permanent until the 1993 outage. The inspector verified that the relays were installed and working.

The inspector also reviewed several other items on the list, verifying that the actions were taken. The items appeared to be implemented as committed.

17. Personnel Performance Issues - Units 1, 2, and 3 (61726, 61703, 71707, and 92700)

During this inspection period a number of personnel performance issues were identified by the inspector and by the licensee. These issues divided into two categories, attention to detail and worker responsibility.

a. Attention to Detail Issues

1. Unit 1/Unit 2 COLSS Loss without TS Action Statement Documentation - The Core Operating Limits Supervisory System (COLSS) was out of service three times, though the inspector identified that operations personnel failed to log entry into the applicable Technical Specification Action Statements. These events occurred in Unit 1 on June 20 and 25, 1991 and in Unit 2 on July 15, 1991. Procedure 40AC-9OP02, "Conduct of Shift Operations," states in Paragraph 3.4.2.4 that "the information entered in the Unit Log shall include . . . entering and exiting Technical Specification action statements

. . ." In each case, the inspector confirmed that the required actions were taken, and that this appears to be only a log keeping deficiency. These examples constitute an apparent violation of NRC requirements. The licensee issued a memorandum dated July 30, 1991, to all Unit Operations Managers emphasizing the need to log entry into COLSS action statements. The violation is not being cited because the criteria specified in Section V.A. of the Enforcement Policy were satisfied (NCV 528/91-26-02 and 529/91-26-02).

2. Unit 1 Addressable Constants not Reset - On July 5, 1991, Unit 1 personnel determined that four Core Protection Calculator (CPC) Channel B addressable constants were inaccurately reset following a CPC functional test on July 3, 1991. The error was identified following a reactor operator's observation of a minor (less than two percent) conservative difference in flux indicated by CPC Channel C. The inspector noted that the difference was fortuitously conservative and small, and that it had not been identified during the independent checks required by the surveillance test done on July 3. Surveillance test procedure 77ST-1SB08, step 8.9.1.4, requires that the Channel B values of all addressable constant points be verified to be equal to Channel B values in the addressable constants log book. Additionally, even though the difference was within the acceptance criteria of the channel checks performed as part of test procedure 41ST-9ZZ16, "Midnight Surveillance Logs," the inspector noted that this was another missed opportunity to identify the error, and is essentially the same comparison by which a day shift reactor operator discovered the error. The incorrect performance of surveillance test 77ST-1SB08, "CPC Channel 'B' Functional Test" is an apparent violation of NRC requirements (Violation 528/91-26-03).

   The high level safety significance of the CPCs is clear to ensure correct reactor trip setpoints are maintained. Accuracy and attention to detail in entering CPC addressable constants are essential.

   The licensee initiated Condition Report/Disposition Request (CRDR) 1-1-0027 to investigate this event.

3. On July 4, 1991, the inspector observed an unattended man-lift located adjacent to the "B" train essential control room ventilation unit and ducting with the wheels not locked. The manlift was relocated and properly stored.

4. The inspector noted an unattended scaffolding cart adjacent to the Unit 2 control room auxiliary relay cabinet. The wheeled cart had several scaffold bars loaded onto it and was not secured. Although scaffold workers returned within a few minutes, the inspector noted that leaving such transient material unattended and unsecured is a seismic hazard and does not meet the intent of the licensee's housekeeping procedure.

The licensee then removed the cart from the control room area and carried scaffolding by hand to complete the job.

5. On July 2, 1991, in Unit 3 the inspector noted that steps 3.1, 3.2 and 4.1 for Appendix A of work order 503034 for 3J-SGA-PV-0313B had been completed, but had not been signed off. The inspector questioned the worker who indicated that steps were normally signed off when the work was complete. The worker acknowledged the requirement and expectation that they be signed off concurrently. The worker was disciplined by the licensee and Central Maintenance used this example in supervisory meetings to reinforce the expectation that the work control program be followed.

6. The licensee committed to action in their response to Enforcement Item 530/91-04-01 by July 15, 1991, yet was not complete by the end of this inspection report period. This issue is discussed in detail in Paragraph 2.b.1.

7. There were additional personnel performance issues associated with the control element drive mechanism fan and stack bolting failures issue discussed in Paragraph 11.

b. Worker Responsibility Issues

Inspection Report 50-528/91-19 discussed worker responsibility issues as examples where workers could have or did identify problems either with procedures or in the field yet did not take appropriate action to address these deficiencies. Two additional examples were identified by the inspector during this reporting period.

1. On July 16, 1991, during the performance of 36ST-2SE03, "Excore Safety Linear Channel Quarterly Calibration," the inspector noted that step 8.5.2.2 identified a cable as 2E-SE57-BC-1XC-CE62 yet the worker identifying this cable in the cabinet noted that the cable tag read 2E-SE57-BC-1XC. The inspector questioned the worker who said that the difference was not significant and did not require any further action. ICR 49869 was issued to correct this discrepancy.

2. Surveillance test procedure 73ST-9ZZ20, "ASME Section XI Offline Pressure Verification," directs the worker to raise the system pressure to 90% of the relief valve setpoint, then slowly (approximately 2 psig per second) raise the pressure to the relief setpoint. On July 5, 1991, during the performance of this procedure the inspector noted that the worker raised the pressure above 90% of the set pressure at approximately 20 psig per second until the pressure was within approximately 100 psig of the set pressure, then increase the pressure to the set pressure. There was no notation of this difference in any of the work documents, and neither the Component and Specialty Engineering (C&SE) representative nor the QC Inspector present raised this question. The inspector was informed that the test rig could not be ramped up any more slowly than 20 psi per

second. The inspector noted that the worker was able to stop the pressure rise at any point. Subsequent discussions with Engineering concluded that the procedure was not appropriate for use with this test rig and that there was a human factors issue of possibly not being able to read the actual relief pressure accurately. The inspector concluded that the relief pressure was determined repeatedly within the accuracy required by the ST procedure. The Manager, C&SE, committed to resolving the administrative problem in an upcoming revision to the procedure. The QC Director concluded that the QC inspector should have raised this question and addressed this concern with all QC inspectors.

The inspector concluded that the corrective action identified in each of these cases was appropriate for the concerns noted. In addition, the inspector noted that the Vice President, Nuclear Production, directed all work groups on site to stop work on July 26, 1991, to discuss attention to detail and recent examples of attention to detail concerns. The inspector concluded that this appeared to be appropriate management measures in resolving this concern.

Three apparent violations (one cited and two non-cited) of NRC requirements were identified.

18. Corrective Action Program Evaluation - Units 1, 2, and 3 (92720)

The licensee is required by 10 CFR Part 50, Appendix B, Criterion XVI, to have corrective action programs that will identify, follow, and correct safety-related problems. The licensee has several programs to identify and correct safety-related problems. These programs include Material Nonconformance Reports (MNCRs) dealing with equipment (hardware) problems, and Condition Report/Disposition Requests (CRDRs) or Quality Deficiency Reports (QDRs) dealing with procedural or activity problems. Items requiring additional engineering evaluation are documented by Engineering Evaluation Requests (EERs) and significant problems are documented by Corrective Action Reports (CARs). The licensee also tracks NRC/INPO open items and commitments on the Commitment Action Tracking System (CATS).

The inspector reviewed several of the above programs to assess the effectiveness of these programs. In general, the programs referenced each other where appropriate, had methods for rating the importance of each problem, and met the requirements of 10 CFR Part 50, Criterion XVI.

The licensee is in the process of modifying their programs. The QDR program is scheduled to be phased out over the next year, with no new QDRs to be generated except by QA. Problems identified as a QDR will now be handled by the CAR program, as a lower severity level CAR. The EER program is to be changed, in that EERs which are plant improvement ideas will be handled by another program. The EER program also refers to other programs (MNCR, CRDR) in its procedure, so that these programs will track the corrective actions. The CRDR program was initiated in June, and was not extensively reviewed by the inspector. The licensee plans to monitor the CRDR program and assess its effectiveness.

The licensee is trying to improve the timeliness for resolution in the corrective action processes, and is monitoring the backlog in the various corrective action systems. The MNCR backlog was up because of the large number of fire protection items identified during recent walkdowns. The EER backlog is declining, due to a review which transferred EERs that are plant betterment ideas or closed EERs which had been resolved.

a. Material Nonconformance Program Description

The administrative controls for Material Nonconformance Reports (MNCRs) are described in procedure 60AC-0QQ01, "Control of NonConforming Items." MNCRs can be initiated by any individual for a nonconformance on safety-related or quality augmented equipment or items. Conditions requiring a MNCR include components which do not conform to design, procurement or contract specification; parts not installed in accordance with approved drawings, specification or design documents; equipment or components that are physically damaged (beyond normal wear) or were subject to conditions for which they were not designed; and failed or damaged components from use of incorrect materials, procedures, or inadequate design. MNCRs may also be initiated on non-quality related equipment. MNCRs are not required for replacement of normal wear items (i.e. gaskets, packing, light bulbs), out of tolerance (but not failed) instrumentation which can be calibrated, and weld discontinuities discovered in-process.

Following initiation, the MNCR is reviewed for validity and reportability, and assigned a unique number. The MNCR is then dispositioned to use-as-is, repair, rework, or scrap. The licensee's quality control organization reviews the disposition and notes if they concur with the disposition.

Material Nonconformance Report (MNCR) Review

The inspector reviewed a selected set of MNCRs to assess the licensee's evaluation and compliance with 60AC-0QQ01. No problems were identified during the review. The following documents the inspector's findings.

MNCR 90-ZC-0011

This MNCR documented a concern with an electrical penetration into containment in that electrical redundancy requirements might not be met. This electrical requirement (specified in the FSAR) was for redundant fault protection which required two fuses, two breakers, or a fuse and a breaker in series to limit overcurrent in the circuit which could affect the penetration. The circuits in question were the security card readers for the containment personnel air locks. To correct the problem, the licensee issued design changes to the circuit. The circuits were also de-energized as an interim measure until the design was implemented. Due to the unique aspects of this MNCR, it was not considered to apply to other electrical penetrations.

MNCR 90-RC-0002

This MNCR documented that the Reactor Coolant Pump (RCP) oil leakage tube was not installed per drawings of the system, with improper supports and improper bends in the collector tray and the tubes were installed using unions.

This MNCR was initially determined not to be reportable since the system was non-quality related. It was subsequently determined to be a quality system since it is required by 10 CFR 50, Appendix R. The deficiencies were corrected. The reportability of the issue was then evaluated and determined not to be reportable, since safe shutdown could be achieved with these problems. The actions taken appear appropriate.

MNCRs 90-AF-0002, -0003, -0004

These MNCRs document a concern with the roll-off time and governor control for the Auxiliary Feedwater (AFW) terry turbine. This condition was found through testing of the Unit 2 AFW pump and as a result, MNCRs were added to the other units. It was discovered through this testing that the terry turbine had a potential for overspeeding.

The cause of this condition was the presence of water in the steam line and as a result a temperature monitoring program was established. The steam line temperature in Unit 2 was 125 degrees F., compared to 190-200 degrees F. in the other units. The MNCR states that two steam admission valves in unit 2 were reworked, becoming essentially leaktight. With the lack of warming steam, the line became cold, allowing steam in the line to condense when the steam admission valves were closed.

As a conditional release for this problem, the torque setting to shut one of the Unit 2 steam valves was readjusted. This caused a steam admission valve not to seat as tight, letting some steam by and maintaining the line warm. The line temperatures are periodically monitored. This interim repair appears to work, in that the pump is not overspeeding. The licensee is considering a long term fix to this problem.

MNCR 91-PK-2002

During a walkdown of Class 1E station batteries and battery racks, some of the racks were found not to be in contact with the battery. This MNCR documented this and the locations of these gaps. The gaps were less than 1/4 of an inch, but the vendor instructions require that the cells be in snug contact with the racks. This condition could violate the seismic qualification of the battery and was contrary to the manufacturer's installation instructions.

The MNCR was dispositioned to repair. As an interim corrective action, the gaps were shimmed. This condition was discussed with the vendor who concurred with the solution. This MNCR repair was evaluated per 10 CFR 50.59 and found to be acceptable.

b. Condition Report/Disposition Requests Program Description

The current CRDR process is relatively recent for the licensee (effective 5/30/1991) and replaces the Problem Reporting System. The administrative controls for Condition Report/Disposition Requests (CRDRs) are described in procedure 90AC-0IP04, "Condition Reporting." CRDRs are required to be initiated by any individual for identified conditions which may affect the safe and efficient operation by the licensee. Conditions requiring a CRDR include plant transients including reactor trips, turbine trips, or control system problems; control breakdown in operations, maintenance, design or procurement activities; failure to meet an operational commitment; personnel errors; procedure deficiencies; and investigation into common mode failures. The shift supervisor is required to initiate a MNCR if the conditions described in the CR/DR meet the requirements of a MNCR.

No CRDRs were reviewed by the inspector.

c. Quality Deficiency Report Program Description

The administrative controls for Quality Deficiency Reports (QDRs) are described in procedure 60AC-0QQ03, "Quality Deficiency Reports." QDRs are required to be initiated by any individual for identified conditions which may be a noncompliance or other condition adverse to quality. QDRs are for conditions other than a material nonconformance. Conditions requiring a QDR include use of unapproved, incorrect, inadequate, unreviewed or out of date documents; failure to comply with procedures, drawings, instructions, specifications, etc. which are not administrative in nature; unauthorized change to in-process or completed QA records; and confirmed adverse trends in activities. Significant QDRs are superseded by a CAR. Since the QDR program is being superseded by the CRDR program, the QA organization is the only organization which is currently writing QDRs. The QDR process is to be phased out over the next year.

Following initiation of a QDR, the QDR is reviewed for validity and reportability, and assigned a unique number. The QDR is then classified and an apparent cause to the QDR is assigned. The manager of QA&M or designee asks the affected organizations for a response within 30 days. The affected organization's response is reviewed by QA. If the response is acceptable the affected organization is notified and the corrective actions taken are later verified.

Quality Deficiency Report (QDR) Review

The inspector reviewed a selected set of QDRs to assess the licensee's evaluation and compliance with 60AC-0QQ03. The inspector reviewed the following documents:

QDR 91-0120

This QDR documented a concern with the control and use of Measurement and Test Equipment (M&TE). Specifically, the use of torque wrenches was not in accordance with procedures and FSAR statements. Three examples were given where torquing was performed on equipment, but the torque wrench was not documented as still accurate after its use. Inaccuracies with M&TE are noted on Out of Tolerance Notices (OTNs).

The affected organization (Work Control) evaluated this QDR and stated in the reply to QA that no deficiency existed and therefore no corrective actions were needed. QA disagreed with this initial response, opened CAR 91-010, and closed this QDR. The opening of CAR 91-010 was based on similar issues in other open and closed QDRs. The response to CAR 91-010 was assigned to the Site Maintenance Manager.

The initial response identified that the deficiencies included a failure to consistently identify devices previously tested from the time of a previous calibration, and failure to resolve M&TE OTNs in accordance with procedures. The maintenance department issued guidelines on the use of M&TE, created usage records for M&TE, and are in the process of evaluating open OTNs. This CAR is still open.

QDR 91-038

This QDR noted that the ASME Section XI technical review be conducted on certain surveillance tests. Certain surveillance test packages did not receive an ASME Section XI review prior to being sent to document control.

The cause of the event was personnel changes immediately prior to the time of the event. The affected organization reviewed surveillance tests for the previous six months to verify that the review was performed. If the review had not been performed, the review would be performed. This response was accepted by the quality organization.

d. Engineering Evaluation Requests Program Description

The administrative controls for Engineering Evaluation Requests (EERs) are described in procedure 73AC-0EE01, "Engineering Evaluation Request." An EER can be initiated by any organization or individual onsite if an engineering evaluation is requested. EERs include technical clarifications, request for a root cause evaluation for component or equipment failure, addressal of a design deviation evaluation on non-quality related systems or components, and documentation of action plans. After an EER is initiated, the immediate supervisor reviews the EER for validity confirming that it cannot be resolved through normal work processes. If the EER addresses an unauthorized deviation from plant documents, the initiator's manager reviews and approves the EER. An EER is then assigned a number and an engineer for evaluation.

Engineering Evaluation Request Review

The inspector reviewed a selected set of EERs to assess the licensee's evaluation for compliance with 73AC-0EE01. The following EERs were reviewed:

EER 89-PV-001

This EER documented a denied relief request from the NRC on the In-Service Test (IST) program. The denied relief request concerned raising the acceptable, alert, and required action ranges on pump differential Pressure (dP) above the reference value of pump dP. The EER was to revise all applicable procedures converting allowable dP to the ranges to keep them within the code.

The inspector questioned why it was appropriate to change values back to the original code requirements. The inspector was informed that NRR had informed the licensee to use the program they had in 1985 and it would be reviewed later. At a later review, this difference from the code was not allowed. The licensee changed the procedures to reflect the new values.

EER 90-FB-085

This EER was initiated to evaluate if missing oil lift covers on the RCP oil collection system was a reportable event. The purpose of these covers, described in the FSAR, is to minimize the effects of oil spray if the high pressure line were to rupture, which could create a fire in the vicinity.

The only high pressure source is when the the oil lift pump starts. The oil lift pump either starts manually when the RCP starts, or automatically when the RCP is shutdown. The interim actions were to rack out the oil lift pump breakers to prevent the oil lift pump from starting. The engineering department evaluated this EER as not reportable since safe shutdown could be achieved.

EER 91-CL-010

This EER documents an evaluation for a change to how Local Leak Rate Tests are performed on certain Shutdown Cooling System containment isolation valves. The change was to test the valves under water conditions, instead of the air conditions currently specified. Such a change would involve a change to the technical specifications and the FSAR. The testing of these valves was also documented in a NRR Safety Evaluation Report (SER) and was not accepted.

In discussions with the licensee, this EER is still being evalulated and no decisions have been made with respect to implementing this change to the LLRT testing method.

e. Corrective Action Program Description

The administrative controls for Corrective Action Reports (CARs) are described in procedure 60AC-0QQ02, "Corrective Action." CARs are required to be initiated for major program deficiencies or adverse trends which, if left uncorrected, could have a serious effect on safety or operability. The programmatic deficiencies identified on CARs include widespread failure to address the requirements of instructions or procedures, widespread failure to train personnel in QA requirements and widespread or deliberate failure to manage or supervise personnel carrying out their assigned duties. A CAR can only be initiated by Quality Assurance/Quality Control, the Independent Safety Engineering Department or the Nuclear Safety Department. Other departments have used the QDR process for these concerns.

Corrective Action Report (CAR) Review

The inspector reviewed a selected set of CARs to assess the licensee's evaluation for compliance with 60AC-0QQ02. The following documents the inspectors review:

CAR 89-0081

CAR 89-0081 concerned the calibration of the diesel generator lube oil and jacket water temperature controllers. The controllers were calibrated and operated outside the range specified in the Final Safety Analysis Report (FSAR). The range on the controllers were changed under design change packages written in 1984 for Unit 1. The same changes were made in Units 2 and 3.

The licensee's QA department rejected the engineering organization's initial response because the engineering department did not describe why this problem should not recur. The cause was then documented that it occurred when the plant did not have a formal 10 CFR 50.59 process, and design changes subsequent to the 1984 time frame were controlled.

CAR 90-0024

CAR 90-0024 concerned the control of Temporary Modifications (TMs) in that the review forms for the TMs were not performed in a timely manner. The missed review was a quarterly justification for the continued use of the TM. These deficiencies were previously noted on CAR 89-0048.

The cause for this problem was determined to be lack of clear procedural guidance for these justification reviews. The procedure was changed to specifically require the reviews to be done and to shift some of the responsibility for the justification to the unit

managers. Further, all reviews were verified to be done for that quarter.

CAR 91-0001

CAR 91-0001 was concerned with Layup Activity control in the steam generators. These problems had been identified by the NRC during the Diagnostic Evaluation Team (DET) inspection. The Layup Program is to provide protection from corrosion degradation during outages and storage. The CAR was initiated when recent audits by QA indicated that no program existed.

The cause of the problem was determined to be lack of management oversight and failure to document Layup Task Committee (LUTC) meetings. The initial response by the affected organization was that they would document meeting minutes, revise the Layup Activity Control procedure and revise the Business Plan to assure that the LUTC is established. This initial response was rejected by QA, since the root cause was only described as an apparent cause; it did not include interim corrective actions, or completely describe the actions to prevent recurrence. The affected department (Chemistry) responded, stating that the cause was ineffective implementation of the program and lack of management oversight. The interim corrective actions were described and the LUTC chair was assigned to the Chemistry Manager. This response was accepted and the actions verified by QA.

CAR 91-0005

CAR 91-0005 concerned the site Lubrication Program. The specific deficiencies noted were that the Lubrication Manual was not being revised when changes were made to it and the manual was not reviewed by qualified personnel. It was further found that: operations and maintenance were adding different oils to various pumps; the traceability of bulk materials and labeling in the field was lacking in some cases; and chemical classification labels were not always attached to secondary containers.

The cause of the deficiencies were the lack of Preventive Maintenance tasks incorporating the guidance in the lubrication manual and the failure of operations and maintenance to implement labeling requirements for secondary containers. The licensee halted adding oil to equipment until the correct oils were determined. The licensee initiated corrective actions for this problem to prevent recurrence. The interim actions and final corrective actions were determined to be appropriate by QA.

The inspector concluded that the licensee's corrective actions programs appeared to meet regulatory requirements.

19. Exit Meeting

An exit meeting was held on July 26, 1991, with licensee management during which the observations and conclusions in this report were

generally discussed. The licensee did not identify as proprietary any materials provided to or reviewed by the inspectors during the inspection.