U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.:	50-528/90-23, 50-529/90-23 and 50-530/90-23
Docket Nos.:	50-528, 50-529, 50-530
License Nos.:	NPF-41, NPF-51, NPF-74
Licensee:	Arizona Public Service Company P. O. Box 52034 Phoenix, AZ. 85072-2034
Facility Name:	Palo Verde Nuclear Generating Station Units 1, 2 & 3
Inspection Conducted:	May 27 through July 14, 1990

Inspectors: D. Coe, Senior Resident Inspector
F. Ringwald, Resident Inspector
J. Sloan, Resident Inspector
P. Narbut, Senior Resident Inspector (Diablo Canyon)

Approved By: H. Wong [signature] 8/23/90
H. Wong, Chief — Date Signed
Reactor Projects Branch, Section II

Inspection Summary:

Inspection on May 27 through July 14, 1990 (Report Numbers 50-528/90-23, 50-529/90-23, and 50-530/90-23)

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors, and an inspector from the Region V staff. Areas inspected included: previously identified items; review of plant activities; engineered safety feature system walkdowns; monthly surveillance testing; monthly plant maintenance; worker in a high radiation area (HRA) without proper dosimetry - Unit 1; plant startup from refueling - Unit 1; confirmatory action letter followup - Unit 1; over-dilution, excessive power rate increase - Unit 1; main steam isolation due to restoring the steam bypass control system with a large demand - Unit 1; inoperable safety injection tanks - Unit 1; installation/testing of modifications - Unit 2; control room controlled document discrepancies - Unit 2; pressurizer heater replacement - Unit 2; reactor coolant pump breaker trip - Unit 2; missed reactor coolant system boron sample - Unit 2; reactor coolant system (RCS) spill - Unit 2; reactor (Rx) power cutback - Unit 3; cracked reactor trip breaker arc chutes - Unit 3; OSHA concern: non-ionizing radiation - Units 1, 2 and 3; review of licensee event reports, Units 1, 2 and 3; and review of periodic and special reports - Units 1, 2 and 3.

During this inspection the following Inspection Procedures were utilized: 30702, 30703, 37838, 61705, 61707, 61708, 61726, 62703, 71707, 71710, 71711, 72700, 72700, 92700, 92701, 92702, 92703, 93001, and 93702.

Results: Of the 23 areas inspected, 2 violations were identified and are being cited. The violations involve: (1) the failure of a mechanic foreman to comply with the applicable Radiation Exposure Permit when a High Radiation Area was entered without the required alarming dosimeter, and (2) the failure of an Auxiliary Operator to follow procedures for the manual operation of an Atmospheric Dump Valve.

Three non-cited violations involved: (1) the inadvertant powering of Safety Injection Tank vent valves, (2) the use of "Information Only" copies of the Unit 2 Core Data Book, (3) a missed Technical Specifications surveillance test due to an inadequate test procedure.

General Conclusions and Specific Findings

Significant Safety Matters:	None
Summary of Violations:	2 Cited Violations and 3 Non-Cited Violations
Summary of Deviations:	None
Open Items Summary:	11 items closed, 2 items left open, and 6 new items opened.

DETAILS

1. Persons Contacted:

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

Arizona Nuclear Power Project (ANPP)

*R. Adney,	Plant Manager, Unit 3
*J. Bailey,	Vice President, Nuclear Safety and Licensing
#T. Bradish,	Compliance Manager
P. Caudill,	Site Services Director
W. Conway,	Executive Vice President - Nuclear
E. Dotson,	Director Site Engineering and Construction
*R. Flood,	Assistant Plant Manager, Unit 2
#J. Fogarty,	Operations Outage Manager, Unit 2
#*R. Fullmer,	Quality Assurance and Monitoring Manager
*S. Gross,	El Paso Electric Engineer
*K. Hall,	El Paso Electric Engineer
D. Heinicke,	Plant Manager, Unit 2
*R. Henry,	Salt River Project, Site Representative
*P. Hughes,	Radiation Protection/General Manager
*W. Ide,	Plant Manager, Unit 1
*A. Johnson,	Compliance Supervisor
#D. Kanitz,	Compliance Engineer
#*S. Kanter,	Participant Services, Senior Coordinator
#A. Khanpour,	Site Nuclear Engineering Supervisor
*J. Levine,	Vice President, Nuclear Power Production
*W. Marsh,	Plant Operations and Maintenance Director
*J. Napier,	Compliance Lead
*G. Overbeck,	Technical Support Director
#M. Radoccia,	SME Nuclear Engineering Manager
*V. Rhodes,	Document Control Supervisor
*R. Rouse,	Compliance Supervisor
J. Scott,	General Manager of Site Chemistry
*J. Sills,	Rad. Protection Tech/Svcs. Acting Manager
E. Simpson,	Vice-Pres. Nuclear Engineering & Construction
*D. Stover,	Nuclear Safety Manager
#M. Winsor,	NSSS System Engineering Supervisor

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

#Attended the Exit meeting held with NRC Inspector Paul Narbut on June 29, 1990.

*Attended the Exit meeting held with NRC Resident Inspectors on July 19, 1990.

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

Unit 1:

a. (Closed) Enforcement Item (528/89-16-03): "Inoperable Atmospheric Dump Valve No. 178" - Unit 1 (92702)

The remaining actions committed to by Arizona Public Service Company (APS) are to upgrade operating procedures and train operators. The operator training schedule was discussed in Inspection Report 50-528/90-03 and appeared appropriate. The operating procedure upgrade schedule was considered inappropriate and has been revised and documented in APS memo 294-000144-JWD from J. W. Dennis to T. R. Bradish. The schedule for upgrading operating procedures is:

- o September 3, 1990 - December 20, 1991, - upgrade Abnormal Operating procedures.
- o January 6, 1992 - January 2, 1996, - upgrade Normal Operating Procedures.

The inspector considered that the specific actions associated with the procedure changes and operator training relative to Atmospheric Dump Valve (ADV) operation is complete and complies with the licensee's associated independent verification and locked valve/breaker procedures.

The licensee's large scope, long range upgrade program is an initiative well beyond the scope of the original violation. The inspector questioned the adequacy of the timeliness of the large scope procedure review relative to ensuring independent verification requirements are met and will followup under Followup Item (528/90-23-04). This item is closed.

b. (Open) Followup Item (528/90-03-02): "Load Shed Potential Transformer Failure" - Unit 1 (92701)

This event resulted in two root cause of failure Engineering Evaluation Requests (EER) to evaluate the Potential Transformer (PT) failures. EER 89-NA-049 was closed stating that the PT failure evaluation will be documented in EER 90-NA-002. General Electric is performing the root cause evaluation and the estimated completion date is October 30, 1990. This item will remain open until EER 90-NA-002 is complete and evaluated by the inspector.

c. (Open) Followup Item (528/90-03-03): "Fuel Building Rollup Door Damage/Ventilation Damper Jumper Installation" - Unit 1 (92701)

This event resulted in Engineering Evaluation Request (EER) 90-ZF-009 and Incident Investigation Report (IIR) 3-1-90-008. IIR 3-1-90-008 is complete and includes a Human Performance

Evaluation System report. The inspector reviewed IIR 3-1-90-008 and had no further questions. EER 900-ZF-009 is to evaluate the physical equipment consequences of this event and is not yet complete. This item will remain open until EER 90-ZF-009 is complete and evaluated by the inspector.

d. <u>(Closed) Enforcement Item (528/89-30-01): "Expired Flammable Storage Permits" - Unit 1 (92702)</u>

This item involved three expired flammable storage permits which were found on flammable storage lockers. The revision to Procedure 14AC-0EP03, Control of Transient Combustibles, was approved on July 5, 1990, and effective on July 13, 1990. The inspector reviewed this revision and concluded that it appeared to be appropriate. The inspector was provided documentation to substantiate that Site Modification 13-SM-ZZ-001 has been funded and would add several permanent storage locations for safe combustible storage in the plant. The implementation of instruction change requests in work planning and work control procedures appears to be consistent with 14AC-0EP03 and is scheduled for inclusion in a major rewrite by August 1990. The Quality Assurance Monitoring program has completed approximately twenty monitoring reports and is planning to continue to monitor this area for at least three months beyond July 13, 1990, the effective date for the revision to 14AC-0FP03. The inspector concluded that all corrective action is either complete or scheduled to be complete on an appropriate schedule. This item is closed.

<u>Unit 2:</u>

a. <u>(Closed) Followup Item (529/89-30-04): "Control of Maintenance Technical Manuals" - Unit 2 (92701)</u>

This item resulted from the use of a superseded technical manual for maintenance when the current manual was available and approved for use. The licensee concluded that personnel had not followed existing procedures, which require work planners to confirm that only current approved technical manuals are used in work documents. However, the licensee chose to strengthen this area by incorporating this specific requirement into procedures 30DP-9WP02, Work Planning and 30AC-9ZZ01, Work Control. These changes are complete. The licensee also identified and initiated corrective action on other vendor technical manual program deficiencies. These include enhancing page level control for manual revisions, and restricting the use of manuals which have not received review and comments by licensee staff. This item is closed.

b. <u>(Closed) Unresolved Item (529/89-30-05): "Safety Injection Actuation and Main Feedpump Suction Pipe Overpressure" - Unit 2 (92701)</u>

This item involved two issues resulting from the July 12, 1989, reactor trip and subsequent main feed pump suction piping overpressurization. The first issue involved the adequacy of previous corrective actions regarding excessive pressurizer spray valve seat leakage. The inspector reviewed the work history on these valves in all units since startup. The work history shows approximately 60 Work Orders (WO) were issued in Units 1 and 2 over the three years prior to the event. Most of these WOs were to address calibration and seat leakage problems.

Additionally, the inspector observed current operational parameters to assess the condition of the valves in Units 1 and 3, which were at normal operating pressure. In Unit 3, the proportional heaters control at about 50 percent output (or 150 KW) to maintain plant pressure while compensating for seat leakage, bypass flow and ambient heat losses. One set of 150 KW backup heaters augment the proportional heaters. In Unit 1, backup heaters are also used to augment the proportional heaters for steady state conditions. In both units observed, operators indicated that substantially more heaters were previously required due to excessive leakage and that current conditions were noticeably better. Combustion Engineering Standard Safety Analysis Report (CESSAR), Section 5.4.10.2, indicates that the proportional heaters are designed to be adequate to maintain pressure and that the backup heaters are normally deenergized. The current conditions in Units 1 and 3 do not appear to meet this design standard, in spite of noted improvements to the valves.

An analysis of the depressurization event was performed by Combustion Engineering and documented in the Incident Investigation Report (IIR-2-2-89-001). This analysis concluded that the excess pressurizer spray and diminished reserve of backup heaters contributed only slightly to the extent of the depressurization. The performance of the Steam Bypass Control Valves appears to have been the principal contributor to the pressure decrease.

The Engineering Evaluations Department (EED) has performed an evaluation of current conditions and concluded that the spray valves are not leaking excessively. The use of backup heaters is necessary due to ambient losses and normal bypass spray flow. The CESSAR section referenced above assumes a much smaller bypass spray flow rate than has been found necessary to achieve a less than 70 degree F temperature difference between spray line temperature and pressurizer temperature. This increased flow rate, in conjunction with longer than anticipated piping runs, has resulted in both greater ambient heat losses than assumed and greater heater demand to offset

the spray effects on pressure. EED has stated that these CESSAR assumptions, while no longer valid, do not impact on the safety analysis. However, EED has agreed that the CESSAR should be updated to reflect actual plant conditions.

The inspector concluded that the corrective actions taken with respect to the spray valve leakage were adequate and there were no further technical concerns.

The second issue deals with adequacy of corrective actions following the main feedwater pump suction piping overpressurization event. The inspector reviewed IIR-2-2-89-001. One of the corrective actions dealt with the delay in troubleshooting the feedwater suction pressure switches which were found to be deformed several days before the unit was restarted. IIR-3-2-89-032 was performed to evaluate the circumstances leading to this delay. The inspector reviewed this IIR as well. These reports do not address the deficiencies in the initial engineering evaluation of the overpressurization identified by the inspector and reported in Inspection Report 529/89-30. However, the final engineering evaluation, as presented in these documents and in the "Condensate Piping Overpressure Evaluation" dated August 16, 1989, appears to adequately address the technical issues associated with the overpressurization event. The corrective and preventive actions associated with the delay in troubleshooting appear to be appropriate.

The licensee's corrective actions following this reactor trip event were discussed during a management meeting held September 1, 1989 (Inspection Report 529/89-42). The inspector noted that although the licensee acknowledged the lessons learned from this event, the inadequacy of engineering work was not detailed in the investigation report. The NRC will continue to monitor the licensee's long range improvement efforts in this area. This item is closed.

c. (Closed) Enforcement Item (529/89-43-03): "Failure to Notify NRC" - Unit 2 (92702)

This violation resulted from the licensee's failure to notify the NRC of the incapacitation and removal from licensed duties of a licensed operator. This issue is closely related to issues regarding licensed operators' medical records which will be documented in Inspection Report 50-528/90-36. The evaluation of the licensee's corrective actions to this item (529/89-43-03) will be addressed in that inspection report. This item is closed.

d. (Closed) Enforcement Item (529/90-03-01): "Use of Unreliable Emergency Diesel Generator Fuel Oil Storage Tank Level Meter for Surveillance Test" - Unit 2 (92702)

This violation resulted from using a meter with a known reliability deficiency to satisfy a Technical Specification surveillance requirement. The licensee has provided guidance to operations personnel to evaluate such deficiencies and document justification for use of deficient indication equipment in the surveillance test log. Additionally, the diesel generator surveillance procedures have been modified to allow use of alternate indications of fuel oil tank level. These actions appear adequate. The inspector has not identified during routine inspections any further cases of log taking deficiencies by AOs. This item is closed.

3. Review of Plant Activities (71707 and 93702)

a. Unit 1

The unit began the report period in Mode 5. Steam Generator tube plugging was resolved with the installation of a Combustion Engineering tube sheet plug and the discovery and repair of several other leaking tube plugs. Mid-loop operation was entered to support the removal of nozzle dams. The unit entered Mode 4 on June 13, 1990, and Mode 3 on June 14, 1990. The Confirmatory Action Letter (CAL) of December 24, 1989, was lifted on June 24, 1990, and Mode 2 followed immediately thereafter. A manual reactor trip test was conducted on June 25, 1990, and Mode 2 was entered again on June 25, 1990. A slipped rod event during startup testing occurred and was evaluated and resolved. Mode 1 was entered on June 30, 1990. Main turbine control problems were traced to incorrect orifices in the turbine control oil system. The Power Ascension Testing Program was nearing completion and the unit was at 100 percent power at the end of the report period.

b. Unit 2

Unit 2 entered this report period in Mode 6, with major activities associated with the refueling outage in progress. Mode 5 was entered on June 3, 1990. The plant entered Mode 4 on July 2 and Mode 3 on July 3. The reactor was brought to criticality at 10:46 PM, MST, on July 14, and the plant ended the report period in Mode 2.

c. Unit 3

Unit 3 began this report period at 100 percent power. On May 29, 1990, the unit experienced a reactor power cutback when the "A" main feedwater pump tripped as I&C Technicians were completing a preventive maintenance check on the discharge pressure switches (see paragraph 20). Other than minor power

reductions for testing and/or maintenance, the unit remained at 100 percent power for the rest of the report period.

d. Plant Tours

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

- Auxiliary Building
- Containment Building
- Control Complex Building
- Diesel Generator Building
- Radwaste 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 Specification requirements.

3. Shift Staffing - Control room and shift staffing were observed for conformance with 10 CFR 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 would 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.

   The Secondary Alarm Station was included in plant tours.

   The inspector observed one instance in which an escort abandoned his escort duties for a visitor in the Unit 2 auxiliary building for a period of about five minutes. This incident was referred to Region V personnel and was documented in Inspection Report 529/90-29.

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.

No violations of NRC requirements or deviations were identified.

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

Selected engineered safety features 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 systems.

Unit 1

- Emergency Diesel Generators "A" and "B"
- "B" Auxiliary Feedwater System

Unit 2

- Emergency Core Cooling System (ECCS) Containment Sumps - Trains "A" and "B"

Unit 3

- Emergency Diesel Generators "A" and "B"

No violations of NRC requirements or deviations were identified.

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

   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-1EC03	Essential Chilled Water System Inoperable Action Surveillance
o 41ST-1SG03	Testing Atmospheric Dump Valves in Mode 3
o 41ST-1SG05	Atmospheric Dump Valves Nitrogen Accumulator Drop Test
o 77ST-1SB08	Core Protection Calculator Channel "B" Functional Test

Unit 2

Procedure	Description
o 31ST-9SI01	Cleaning/Inspection of ECCS Sumps
o 32ST-9SF02	Control Element Drive Mechanism Circuit Breaker Surveillance Test
o 42ST-2ZZ20	Remote Shutdown Disconnect Switch and Control Circuit Operability
o 73ST-2DG01	Integrated Safeguards Surveillance Test Train "A"
o 73ST-2XI02	Section XI Valve Stroke Timing for Steam Generator No. 2 Containment Isolation Valves. During the performance of 73ST-2XI02 for steam line drain valves, communications were noted by the inspector to be formal and control room operators exercised good control of the evolution.

Unit 3

Procedure	Description
o 36ST-9SA11	Engineered Safety Features Actuation System Train "A" High Risk Subgroup Relay Monthly Functional Test
o 43ST-3ZZ04	Weekly Shutdown Electrical Distribution Checks

No violations of NRC requirements or deviations were identified.

6. Monthly 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

- o Steam Bypass Control System Valve Dynamic Response Time Test
- o Oil sampling in LPSI "A" Pump Motor
- o Repair Leaking Body to Bonnet Leak on LPSI "B" Suction Check Valve
- o Repair Auxiliary Building Ventilation Ducting
- o Troubleshooting ADV-178 Air/Nitrogen Leak
- o Troubleshooting Steam Bypass Control Valve 1008 Timing Problem
- o Installation of QBN-001 Holophane Emergency Light Unit
- o Burn Test of QBN-003 Holophane Emergency Light Unit

During the performance of a preventive maintenance task to add oil to the crankcase of charging pump CHA-P01, mechanics used approximately five-eights of a gallon of the wrong oil. After running the pump for approximately half an hour after the incorrect oil was added the error was discovered by the licensee maintenance person who added the oil. The pump was stopped, declared inoperable, the system engineer was contacted, the oil taken out, and the proper oil was added prior to the pump being restored to service.

The inspector noted that the licensee's identification of the issue indicated a willingness on the part of craft personnel to identify their own errors.

Unit 2

Description

- o Remove Isolation Valve 2SIB-UV-0676-"B" Containment Sump

- o Retest of 2-E-NGN-L1287 Load Center Main Feed Breaker
- o Atmospheric Dump Valve Nitrogen Regulator FCV-323 Troubleshooting

Unit 3

Description

- o Troubleshooting 3-E-QDN-N02 Emergency Lights
- o Control Element Drive Mechanism Coil Traces 43TP-3SF01

During a review of Work Order (WO) 423113 in Unit 3 for the performance of 36MT-9SG01, ADV Weekly Bonnet Pressure Measurement and Instrument Installation, the inspector noted that no signature was present on the WO cover sheet for Releasing Organization. This signature constitutes permission to perform the work. The Releasing Organization in this instance was Operations and the Assistant Shift Supervisor had signed page 6 of 28 of the attached copy of 36MT-9SG01, which constituted permission to perform the work. The inspector concluded that this represented inattention to detail.

No violations of NRC requirements or deviations were identified.

7. Worker in a High Radiation Area (HRA) Without Proper Dosimetry - Unit 1 (61726)

On June 20, 1990, the inspector noted that a Mechanical Maintenance Foreman was in a HRA with only a 0-200 millirem (mR) Self Indicating Dosimeter (SID), rather than also with an alarming dosimeter set at 50 mR as required by the Radiation Entry Permit (REP). The inspector questioned the worker who acknowledged that he had forgotten that his work area was a HRA and had not noticed the posting because he backed down the ladder to the lower level of the "A" Low Pressure Safety Injection pump room. This is a violation of NRC requirements (528/90-23-01).

This was brought to the attention of licensee management who took immediate corrective action. The individual's radiation exposure was evaluated and no overexposure occurred. The individual's work records were reviewed and no other similar incidents have occurred with this individual. The individual asked to brief all the Unit 1 Maintenance Department personnel on the lessons he learned from the event. Management agreed and these briefings will be complete by July 19, 1990.

A Problem Resolution sheet was initiated and a Radiological Controls Problem Report was completed. The worker's access to the Radiological Controls Area (RCA) was removed until the investigation was complete. The Radiological Protection (RP) Lead Technician at the RP "Island" was removed from Shift

Technician responsibilities at the RP "Island" until he completed an oral knowledge review with the unit RP Manager. The day the RP Technician was to meet for this knowledge review he resigned citing unrelated personal reasons. The RP department concluded that the root cause of the event was the RP Lead Technician at the RP Island failed to provide the worker with proper service in that two separate briefings failed to identify the lower level of the "A" LPSI room as a HRA. In addition, the Maintenance Manager concluded that the worker did not meet his expectations regarding following the requirements of the REP and RP postings. Several actions are in progress to prevent recurrence of this event:

1) The RP department is accelerating their plans to change the excessively conservative posting policy of posting a larger area than necessary as HRAs and Locked HRAs (LHRAs). In the future the RP department plans to post only the immediate area surrounding the sources of exposure requiring HRA and LHRA postings rather than entire rooms or levels. This is a long term effort which will involve establishing dose rate guidelines for the location of HRA and LHRA boundaries, procedure changes and training. This site effort will be complete by September 30, 1990.

2) Unit 1 RP department created an RP Restart Plan which is a notebook containing survey and posting changes which were required for the various power levels with required notifications for the Unit 1 RP Manager.

3) The RP department is accelerating the plan to use reverse background posting sign inserts.

The inspector agrees with the preliminary conclusions reached by the licensee. One violation of NRC rquirements was identified.

8. <u>Plant Startup From Refueling - Unit 1 (71711, 72700)</u>

The inspector evaluated the Emergency Diesel Generators and the Motor Driven Auxiliary Feed Pump AFB-P01 system for proper restoration from the refueling outage. No discrepancies were noted which would affect component or system operability.

The inspector reviewed 41OP-1ZZ03, Reactor Startup, and noted that it contained revisions which addressed concerns the inspector raised after observing 42OP-1ZZ03, Reactor Startup, used for a reactor startup at Unit 2 on September 22, 1989, and described in Inspection Report 50-529/89-43, paragraph 12. The inspector observed the Unit 1 reactor startup on June 24, 1990, and had no concerns. The inspector noted that after Reactor Engineering told Operations they were ready for Operations to perform the startup, the Assistant Shift Supervisor announced that they were starting to pull regulating group control rods

and then the Reactor Engineer asked Operations to wait two more minutes so Reactor Engineering could get their paperwork ready. The inspector particularly noted the Shift Supervisor's ability to keep this confusion from affecting his crew's performance. The inspector concluded that the unit appeared ready for the startup and power operations.

No violations of NRC requirements or deviations were identified.

9. Confirmatory Action Letter Followup - Unit 1 (92703)

By a letter dated January 11, 1990, the licensee committed to the NRC to complete 190 action items associated with Unit 1 prior to its restart following the 15 month outage which began after the unit trip of March 5, 1989. These items included lessons learned from the Unit 3 reactor trip event of March 3, 1989, in the areas of Atmospheric Dump Valves, Emergency Lighting, Steam Bypass Control System, and Reactor Coolant Pump Power Supplies. Seventy-two of the items had been closed by the licensee during previous efforts in the restart of Units 2 and 3. The inspector selected an initial sample of fifty-one items for review, thirteen of which came from the category of previously closed items.. All of the above listed systems were included in this sample as well as the instrument air system, operations department training and performance, and post restart commitment progress. Ultimately, over seventy items were reviewed in that additional items were sampled based on questions arising from the review of the initial sample. Further, the licensee's Management Review Committee (MRC) activities were reviewed. The following observations represent licensee weaknesses as they related to restart preparations.

a. Atmospheric Dump Valves (ADVs)

The inspector reviewed the licensee's actions with respect to valve labeling, procedure for manual operation, operability tests, preventive maintenance, training, and nitrogen subsystem maintenance. The following observations were made:

1) The licensee implemented a preventive maintenance calibration check of the nitrogen regulators on ADVs (Item 664), but implemented it only when performance problems occurred during monthly 30 percent stroke testing or quarterly accumulator pressure drop testing. The inspector noted that the licensee performs calibration checks on pressure regulators in nonsafety-related systems and questioned why the safety-related ADV nitrogen system was not routinely checked. The licensee committed to evaluate and implement a routine calibration.

2) The licensee flushed the ADV nitrogen system to assure the cleanliness quality of the nitrogen supply (Item 670), but subsequently found foreign particulate matter in the pressure regulator, which could have contributed to observed performance problems during testing. More aggressive flushes were performed to achieve satisfactory system cleanliness. However, the nitrogen supply to the ADV accumulators is not filtered and, although the licensee plans to install filters (Post Restart Item 800) by April 1992, no cleanliness monitoring of the ADV nitrogen system was planned. The inspector questioned this lack of monitoring in view of the known problem with particulate matter, the present lack of filters in the supply line, and the potential impact on the performance of the pressure reducer and ADV positioner components. The licensee committed to evaluate and implement nitrogen quality monitoring checks until the permanent filters are installed. The above two items were further described in NRC Inspection Report 528/90-20.

3) While attempting to evaluate the problems with getting ADV nitrogen systems to pass surveillance test 41ST-1SG05, ADV Nitrogen Accumulator Drop Test, the licensee questioned whether temperature had an effect on the outcome of the test. System Engineering's preliminary calculations suggested that a one degree Fahrenheit change during the test would result in approximately one psig pressure change in the accumulator. This calculation was refined by the Nuclear Engineering Department (NED) in Engineering Evaluation Request (EER) 90-SG-114 and a formula was provided to account for temperature changes from the beginning to the end of the test. However, this formula was identified by the inspector to provide invalid results in some cases.

When the ADV-178 accumulator was tested on June 23, 1990, the pressure drop was 30 psig per hour, the upper limit of the acceptance criteria; however, the temperature had increased an average of 0.15 degrees Fahrenheit. When the NED formula in EER 90-SG-114 was used with this data, the results suggested that the ADV-178 accumulator passed its acceptance criteria. These results were documented in EER 90-SG-136. The inspector questioned the validity of this result since with a measured pressure drop of exactly 30 psig per hour, any temperature increase would represent a non-conservative effect on the measured pressure drop and would suggest that the acceptance criteria had not been met. Discussions between the inspector and System Engineering supervision and management revealed that the EER

90-SG-114 formula was based on a two hour pressure drop from 650 psig to 590 psig, rather than the actual documented drop from 625 psig to 565 psig. This difference made the formula in EER-90-SG-114 inappropriate for the actual field conditions and produced results which were invalid from an engineering standpoint. EER 90-SG-136 was subsequently revised using the correct temperature compensation formula.

While a reevaluation of the formula and the test results by System Engineering resulted in accepting the drop test, the inspector concluded that the initial formula in EER 90-SG-114 was inaccurate with respect to actual field conditions and that System Engineering failed to identify this when these results were applied to the initial version of EER 90-SG-136.

b. Emergency Lighting

The inspector reviewed the licensee's restart commitments to install and test emergency lighting. Although the licensee's specific restart commitments were met, further review in this area is documented in NRC Inspection Reports 528/90-02 and 528/90-25.

On June 22, 1990, during a routine plant tour, the inspector noted that three emergency lights indicated an existing high charge condition and brought this to the attention of plant management. One of these units, QBN-004, a Holophane unit located at the 100 foot elevation in the auxiliary building, required a cell replacement and retest. The other two units were dual light units in the 77 foot and 87 foot elevations of the west mechanical piping penetration rooms. One unit required replacement and the other no longer indicated a high charge. The unit which displayed a high charge when the inspector observed it but had returned to normal when the licensee checked it, could merely have cycled briefly to high charge during the inspector's tour which would be consistent with the design of these units. In addition to these problems, the licensee discovered that Control Room emergency light QDN-F01 failed its 8-hour test apparently due to a faulty circuit card. The card was replaced and QDN-F01 passed the test successfully. The inspector expressed the expectation that these and all other emergency lighting discrepancies be included in the ongoing evaluation of the reliability of emergency lighting. The licensee agreed with this and stated that these evaluations were ongoing.

c. Operations

Restart Item 454 addressed the following NRC concern: "Operations Supervision is not adequately establishing, communicating, monitoring, demanding and enforcing a working environment that promotes professionalism, formality, accountability and adherence to high standards of performance." This issue was addressed and closed by the licensee based on issuing several memos. Two of these memos were from the Plant Director to the Plant Managers with copies to other management personnel. These two memos set the tone and standards of professionalism for Palo Verde Nuclear Generating Station. One memo was to all plant personnel which promulgated the Standards for Personnel Performance and Plant Material Condition. This memo included the Expectations For Operations which described expectations for professionalism, formal communication, not proceeding in the face of uncertainty, use of procedures, being alert to changing plant conditions, maintaining control room decorum, and insisting on high quality, professional performance and high standards for all unit personnel.

During the two weeks before the restart of Unit 1, the inspector observed several occasions in which control room operators were not adhering to these standards. In one case, a control room operator pushed another operator sitting in a chair for several feet during the control board walkdown portion of shift turnover. In another case, while in a discussion with the inspector, an operator silenced an alarm, but did not know the nature of the alarm which had been silenced when questioned by the inspector. In a third case, the inspector observed a control room operator direct an Auxiliary Operator (AO) to go to a containment purge valve inside containment where radio communication is poor, "make some noise" to signal the Control Room Operator to open the valve, then "make some more noise" to signal the Control Room Operator to shut the valve, then telephone the Control Room Operator to discuss the results. While this troubleshooting activity transpired, the inspector observed the Control Room Operator proceed as planned and then misunderstand the AO using the radio. During these same two weeks, three self-revealing events also indicated that operators were not always adhering to the established standards. The first event involved rendering all four Safety Injection Tanks inoperable by powering their vent valves as discussed in paragraph 13 of this inspection report. The second event involved restoring the Steam Bypass Control System (SBCS) with a large demand, which resulted in six steam bypass control valves opening rapidly, thereby causing steam generator swell from 50 percent to at least 91 percent, triggering a Main Steam Line Isolation initiation. The Operators followed the

procedure, but, due in part to a procedural deficiency and the operators' failure to fully understand the expected plant response, the operators failed to compensate adequately for the large demand signal prior to restoring the SBCS. This event is detailed in paragraph 12. The third event involving two Auxiliary Operators who failed to properly follow the procedure for manual operation of an Atmospheric Dump Valve as described in paragraph 10.

The inspector considered each of the three inspector observation examples to be of relatively minor safety significance. However, when these three examples are taken as a whole, with the three self-revealing events, a need for additional management attention into control room and operations activities was evident. This was discussed with the Unit 1 Operations Manager and Plant Manager. In addition, Region V management discussed this with senior licensee management. The Plant Manager prepared a briefing paper containing these six events and management guidelines and philosophy to be given to all operators at shift turnover by the Shift Manager. The inspector observed two of these briefings and noted that the briefings were detailed, specific, and clearly expressed management's concerns and expectations. The Plant Manager implemented a previously planned Shift Manager position to provide 24 hour/day-7 day/week management coverage onsite for Unit 1 during the startup preparations and power ascension. The NRC inspector concluded that the licensee's corrective actions were appropriate and that these issues would not prevent the NRC from lifting the December 24, 1989 Confirmatory Action Letter.

d. <u>Preventive Maintenance (PM)</u>

The licensee committed to provide justification for waived PM's which involved performing all PMs that could be performed and having Engineering Evaluation Requests (EERs) for PMs which could not be performed (Restart Item 9). One of these was a PM to calibrate fire protection pump oil pressure switch AJFPNPSL0104, which could not be performed due to the unavailability of parts. The EER to justify why the plant could be operated safely without this PM complete (90-FP-29) was vague and did not document a complete evaluation of the impact on the plant. The inspector questioned this EER and was provided EER 90-FP-030 which fully addressed the impact of the nonperformance of this PM on plant operation. While completing EER 90-FP-030 on June 24, 1990, the licensee also placed a deficiency tag on the local alarm panel for FPNP01A to warn operators that the low oil pressure switch is not within calibration.

The licensee also committed to ensure that there are no other waived PM's which could affect safe plant operation.

This was also documented in Restart Item 9. The licensee accomplished this by reviewing all PMs since commercial operation, identifying those which had been waived, and evaluating each waiver for any current impact on plant operation. In many cases Engineering identified rework which was necessary for safe plant operation. The evaluation of each waived PM was documented on a form which required the engineer to document the basis for the PM, an evaluation as to whether the lack of performance of the PM caused or could have caused degradation, whether Engineering will now grant the existing waiver, whether additional requirements need to be imposed as a result of the waiver, and when the PM is next scheduled to be performed. The inspector evaluated a sampling of these PM review forms for safety-related systems. The majority of those reviewed were properly filled out and contained apparently adequate justification for the determinations made. A significant number, however, contained only a "No" or "None" answer to some questions without additional discussion.

The inspector questioned this during discussions with the Systems Engineering Manager who agreed that the documentation of these evaluations were, in many cases, inadequate. The licensee committed to re-review all PM reviews to select those with inadequate documentation of the justification. Each PM review which is inadequately justified will be re-reviewed and the justification will be adequately documented. Any new additional requirements to be performed as a result of not performing the PM will be brought to the inspector's attention immediately and all re-reviews will be complete and available for the inspector's review by November 1, 1990. This will remain an open item until the re-review, documentation and inspector's review is complete (528/90-23-02).

e. <u>Management Review Committee (MRC)</u>

The MRC functioned essentially the same as during the previous review of the Unit 3 restart program. The MRC at the outset recognized the importance of demonstrating that APS was capable of managing three operating units. As a result, the MRC paid considerable attention to various backlogs. The stated criteria was to maintain a decreasing backlog in Units 2 and 3 while preparing to startup Unit 1. An additional suggestion was first proposed that the MRC review any incidents that occur (site-wide) for evidence of management weakness. This suggestion was apparently not formally or comprehensively undertaken, even though a number of events occurred since December, some of which are documented in NRC Inspection Reports.

Finally, the MRC recognized that the toughest issue which needed to be overcome in the restart of Unit 1 would be personnel readiness. As a result, the MRC maintained a continued interest in training, proficiency watches, and management observations of operators in simulator training and during plant operations. However, as noted elsewhere in this report section, the inspector observed occasions where operator performance either failed to meet established standards or caused an operational problem.

The inspector noted that although maintenance and engineering backlogs appeared to be getting under control, personnel performance continues to require additional management attention. It appears that the MRC successfully served its purpose in the management overview of restart activities.

f. Post-Restart Commitments

The inspector reviewed several of the licensee's closed post-restart action items. One of these (Item 616) was a commitment to evaluate the need for a chemistry post-trip checklist. The inspector noted that the licensee closed the item by referencing the evaluation which determined the need for such a checklist in July 1989 and recommended implementation by December 1989. In June 1990, the inspector determined that the checklist had not been implemented because of an assigned low priority in the procedure change backlog. The inspector noted that the licensee met the letter of the commitment by performing the evaluation, but had not followed it through to completion in a timely manner. Subsequently, the licensee upgraded the priority and expects to issue the checklist by August 31, 1990. The inspector will continue to periodically review completed post-restart items.

g. Summary

The inspector concluded that although the licensee ultimately met their restart commitments, several items as noted above required additional actions subsequent to NRC identification of discrepancies. This appears to reflect the need for a continued and heightened attitude of self-criticism and an insistence on timely, final, and sustained corrective actions by all licensee employees.

No violations of NRC requirements or deviations were identified.

10. Mis-operation of Atmospheric Dump Valve (ADV) in Manual - Unit 1 (93702)

On July 21, 1990, the NRC inspector observed testing of ADV-178, which required the manual operation of the ADV in

accordance with procedure 41DP-1OP01, Manual Operation of Air Operated Valves. Steps B.7 through B.9 in 41DP-1OP01 required the Auxiliary Operator (AO) to lower the manual override shaft, insert the clevis onto the actuator shaft, then manipulate the valve using the handwheel. The AO's difficulties in manually operating ADV-178 indicated a lack of familiarity of the proper operation of the ADVs and resulted in the failure to perform an action required by the procedure. These difficulties are particularly noteworthy in light of the attention on the manual operation of ADVs based on the March 1989 reactor trip event and restart commitments in this area.

When the AO attempted to lower the manual override shaft as specified by Step B.7, the AO rotated the handwheel in the counter-clockwise direction. When the AO encountered resistance, a second AO was consulted and the first AO continued trying to rotate the handle counter-clockwise. After further discussion with the second AO, both AOs together tried to turn the handwheel counter-clockwise. At this point, an SRO assigned to supervise this activity interrupted and reminded the AOs that they had to engage the clevis first. At this point, the first AO turned the handwheel clockwise, lowered the manual override shaft, engaged the clevis, and operated the valve. Step B.8 required the set screw to be tightened when the clevis was engaged to secure the clevis to the actuator shaft. This was not accomplished and when the inspector questioned the AO immediately after this evolution the AO acknowledged that the set screw had been forgotten. This failure to follow the procedure is a violation of NRC requirements (Enforcement Item 528/90-23-03).

The inspector noted that the procedure requirement for tightening the set screw was one of several actions in Step B.8 for engaging the clevis on the actuator shaft. A revision of procedure 41DP-1OP01, dated July 5, 1990, separated the actions by creating separate steps for sliding the clevis onto the actuator shaft, fully seating the clevis, and tightening the set screw. The inspector considers this change to be an improvement to the procedure.

To ascertain whether other AOs had adequate knowledge of the proper manual operation of ADVs, the licensee chose two AOs from Unit 2 and two from Unit 3 and asked them to demonstrate manual operation of an ADV on short notice. The AOs were able to properly operate the ADVs in manual and on this basis the licensee determined that the observed ADV manual mis-operation was a performance issue on the part of the operators involved and not a training issue. The NRC inspector agreed with this conclusion.

The licensee responded to this concern along with other operator performance concerns described in this report by immediately implementing the planned Shift Manager position for the restart activities, addressing the operator performance issues with the operators involved, and conducting management briefings of all Operators, licensed and non-licensed, to discuss management expectations regarding operator performance.

11. Over-Dilution, Excessive Power Rate Increase - Unit 1 (93702)

On July 8, 1990, while diluting the reactor coolant system to increase power, the reactor operator permitted power to increase from 50 percent to approximately 54.5 percent in one hour. This exceeded the Combustion Engineering (CE) fuel preconditioning guidelines of 3 percent per hour. The operators reduced the power increase rate to within CE's guidelines and notified management. The licensee has determined that this is an operator performance issue and has addressed this with the operator involved. The inspector considers this to be another example which suggests that operator performance continues to require additional management and supervisory attention.

No violations of NRC requirements or deviations were identified.

12. Main Steam Isolation Due to Restoring Steam Bypass Control System (SBCS) with a Large Demand - Unit 1 (93702)

On July 20, 1990, while restoring from 36MT-9SF09, Steam Bypass Control System Valve Dynamic Response Time Test, the operators moved the Emergency Off/Reset handswitch from Emergency Off to Reset with a large demand signal, which caused six Steam Bypass Control Valves (SBCV) to open rapidly. This rapid increase in steam demand caused a large swell in both steam generators. Number 2 steam generator swelled from 50 percent to 94 percent level, triggering a Main Steam Isolation Signal (MSIS). The operators stabilized the plant using 41AO-1ZZ31, Inadvertent MSIS, verified the MSIS actuation, stopped SBCV work and notified Compliance and the System Engineer. A Category 2 investigation was initiated and a Licensee Event Report (LER) will be issued. The inspector concluded that this event was an example in which operator performance and procedures needed to be improved and that increased management and supervisory attention appears warranted. The inspector will evaluate the licensee's conclusions during the review of the LER for this event.

No violations of NRC requirements or deviations were identified.

13. Inoperable Safety Injection Tanks - Unit 1 (93702)

On June 17, 1990, all four Safety Injection Tank (SIT) vent valves were discovered by the oncoming Assistant Shift Supervisor to have power available. This was contrary to Technical Specification 3.5.1.(a) and rendered all four SITs technically inoperable. This licensee identified violation is not being cited because the criteria specified in Section V.G. of the Enforcement Policy were satisfied.

Power was provided to the SIT vent valves on June 16, 1990, approximately 25 hours earlier, to facilitate draining of SIT 1A to permit disassembly and repair of valve SI-235, the SIT 1A discharge check valve. Subsequent to the identification of this situation, the licensee immediately removed power from the vent valves, which restored three of the four SITs to an operable status, and initiated a Problem Resolution Sheet and a Category 3 investigation. The inspector noted that the management briefing given to the operations staff on this event appeared appropriate. Further review of licensee actions to improve operator performance will be conducted during review of the required LER.

14. Installation/Testing of Modifications - Unit 2 (37828)

The inspector examined the activities and hardware associated with the plant modification to install a Refueling Water Level Indication System (RWLIS). The system was installed in Units 1 and 2 and was in response to Generic Letter 88-17 regarding mid-loop operations.

The physical installation was examined in the Unit 2 Containment, including instrumentation tubing runs and connections to the pressurizer and the shutdown cooling loop. The inspector verified anchorages, tubing slopes and runs, and labeling.

The inspector also examined records of the installation including the design change package implementing work orders and completed construction inspection plans and testing documentation. The inspector observed the added control room indication in Unit 1 and discussed the new system operation with the Unit 1 operations personnel who had actually used the system during recent steam generator work. The inspector also discussed modification management and testing with construction, planning and system engineering personnel. Further, the inspector requested that the licensee reverify the physical elevation location of the RWLIS differential pressure indication LT-752A, 752B, 753A and 753B. The level indicators were subsequently verified to be at the proper elevation.

No violations or deviations were observed during the inspection. However, several observations, summarized in the following paragraphs, were made by the inspector which were

related to the licensee at an exit interview held on June 29, 1990.

o <u>Design Engineering Methods of Communicating Information To The Field Construction Personnel</u>

The inspector, in examining the paperwork which documented the design change, noted that the elevation tolerance for locating the RWLIS level transmitter was communicated by means of a relatively obscure note in the Design Change Package and limited the elevation deviation to plus or minus one-half inch, which is much tighter than the licensee's normal field installation tolerance of plus or minus 5 inches for instrumentation location. Also any substantial height deviation would lead to a corresponding error in indicated level which could cause inadvertent reactor coolant vortexing in mid-loop operations. The inspector requested the height of the transmitters be reverified, which was done and was found to be satisfactory. The inspector noted to licensee design engineering personnel the type of documents field personnel take to the field to perform such an installation, specifically work orders and installation drawings. These field documents would appear to be the more appropriate means of communication.

o <u>Strength of Construction Inspection Plans</u>

The inspector noted that the licensee's system of using pre-estabished Construction Inspection Plans (CIPs) appeared to be a sound method to ensure important inspection attributes in specialized areas were examined and signed off. The methodology also provides a location to capture any "lessons learned" when recurring installation problems might be encountered.

o <u>Strength of Modification Turnover Process</u>

The inspector noted that the licensee's modification turnover process included a walkdown and acceptance by the user organizations, e.g. Maintenance and Operations. In the case of the RWLIS modification, the walkdown resulted in a change to the nomenclature of the labeled valves (to suit Operations needs) and change in the scaling of control room indicators to reflect specific plant elevations vice relative heights (to suit operator preference and for clarity and consistency with procedures).

While good observations were being made in the turnover process, the inspector commuted that the licensee should continue to emphasize the importance of the turnover process to plant personnel. The inspector noted that the two gage glass installations (for direct visual

observation of mid-loop level) were not labelled to differentiate which gage was reading which hotleg. This situation might lead to operator confusion since the hotlegs will have different levels depending on which shutdown cooling train is being run. The inspector also pointed out that engineering stated they were surprised the gage glasses were not labeled since their "Note xi" to DCP 2FJ-151 stated that all instruments should be "tagged" if not already "tagged." The inspector again pointed out that general design change notes were not a good way to communicate to the field and in this case was not implemented as expected by engineering. Secondly, the inspector noted that the changes identified by the walkdowns could have been anticipated if a closer design engineering/plant user interface had been established in the design planning stages.

o <u>Formality of Test Reviews by Design Engineering</u>

The inspector noted that design engineering had formally documented their review, rationale and acceptance for a special test of the RWLIS system. The inspector considered this a good practice.

o <u>Potential Installation Weaknesses</u>

The inspector observed two design features that could cause potential problems in the future. Specifically, long tubing runs used many swagelock mechanical fittings which provide the opportunity for leaks, whereas welded fittings would have eliminated the potential maintenance problems. Secondly, the final connection to plant systems, e.g. to the pressurizer gas space, were done without the addition of RWLIS vent valves. Other plants have found frequent draining and venting of the RWLIS to be necessary and have provided valves for such operations. While Arizona Public Service Company's current system configuration will allow for such venting by disconnecting swagelock fittings at the high points, this may lead to additional maintenance. On the other hand, the licensee's use of the system in Unit 1 did not indicate that frequent venting was required at Palo Verde.

o <u>Lack of Detailed Operator System Information</u>

The inspector observed that design engineering had not provided an operating diagram of the RWLIS system for operator use. Licensee personnel in standards had produced a diagram in the operating procedure for the system, but the inspector noted that the diagram was not complete nor accurate. Specifically high side and low side drain valves for the level transmitters were not shown on the diagram although they were installed. Additionally, the diagram (Appendix I of procedure

410P-1ZZ16) did not show the label nomenclature associated with the valves in the field.

The inspector explained that other sites had eventually found it necessary to number and label all valves, including those operated by I&C, and to position and verify those valves by specific valve line up sheets. The inspector explained that other sites found these valve line up actions necessary after they experienced continuing valve line up errors especially in the I&C/Operations interface area.

o Conclusion

At the exit interview on June 29, 1990, the inspector concluded that the licensee's installation and testing of the RWLIS system appeared to have been properly performed. Specific observations were related as detailed above. The inspector also made the general comment that it appeared that the design engineering interface with the site could be strengthened as exemplified by the changes required to the RWLIS system after installation which could have been identified prior to the design package issuance, and as exemplified by the designers expectation that general package notes would be an effective way to communicate detailed installation requirements.

Additionally, the inspector noted some of the licensee's strengths in modification control as exemplified by the Construction Inspection Plans (CIPs).

No violations of NRC requirements or deviations were identified.

15. Control Room Controlled Document Discrepancies - Unit 2 (71707)

During a review of the performance of a surveillance test on June 26, 1990, which utilized information from the Unit 2 - Cycle 3 Core Data Book (CDB) to calculate Keff, the inspector identified the fact that the copy of the CDB utilized by control room operators was marked "Information Only" instead of "Controlled Document." The inspector determined that the licensee Document Distribution Center (DDC) issued a Revision 0 of the CDB on April 30, 1990, stamped "Information Only" on all pages, which was the copy in use by Control Room operators in Unit 2. Then, on May 10, 1990, a revision (Rev. 1) was issued which was marked "Controlled Document" and several revised pages were inserted by DDC in the CDB in place of the old pages. The inspector concluded that an inappropriately marked CDB was in use in the control room and that DDC had revised it with an appropriately marked revision but failed to notice the discrepancy, and operators had utilized the CDB at least weekly to meet Technical Specification surveillance requirements without questioning the appropriateness of the "Information

Only" markings. The inspector noted that over two months all five operations crews would have had the opportunity to detect and correct this discrepancy, but did not.

The licensee's immediate corrective action was to issue a controlled document CDB to the Unit 2 control room and to verify that all controlled pages matched the information copy. The licensee concluded that the copies were identical and therefore no technical discrepancy would have resulted from the use of the "Information Only" copy. The licensee checked all other controlled copies of the CDB's and found no other discrepancies. In addition, the licensee issued a Night Order to the operations staff stressing the need to ensure "Information Only" copies of documents are not used in the control room.

On July 11, 1990, a Unit 2 Shift Supervisor, while answering an inspector's question, identified a controlled procedure, 74OP-9SS03, Gaseous Waste System Sampling, which had been revised with a change intended for 74ST-9SS03, Post Accident Sampling System Surveillance Test, and had been placed in the location for 74ST-9SS03. However, the correct and updated 74ST-9SS03 was in the location for 74ST-9ZZ03, Liquid Holdup Tank Surveillance Test. Thus, on July 10 the Unit 2 controlled document set had the following discrepancies:

1) 74ST-9ZZ03 was missing
2) A correct 74ST-9SS03 was mis-located to 74ST-9ZZ03
3) 74OP-9SS03 was incorrectly revised with a change intended for 74ST-9SS03.

The licensee indicated that they had identified discrepancy 3 above and had re-issued 74ST-9SS03 on June 7, 1990, but that it had been mis-filed in Unit 2 to the 74ST-9ZZ03 location. The inspector acknowledged that although the licensee had identified this problem, the corrective action had not been completely effective. The licensee took immediate action to correct these deficiencies and verified these controlled document procedures were correctly located in all other controlled locations. In addition, DDC performed a 100 percent audit of the Unit 2 controlled document set. Finally, the DDC Supervisor issued a memo to all DDC personnel regarding attention to detail. Document distribution also preformed a complete audit of all Unit 2 controlled documents. At the end of the audit, Licensing management evaluated the results and determined that out of 2,229 procedures, 23 deficiencies were noted, but that these had no impact on plant operations.

The inspector concluded that although the requirements of 10 CFR Part 50, Appendix B, Criterion VI, Document Control, had not been met, the licensee's actions were prompt, thorough and appeared to be appropriate. Thus, this violation is not being cited because the criteria in Section V.A. of the Enforcement

Policy were satisfied. The licensee management acknowledged these comments.

16. Pressurizer Heater Replacement - Unit 2 (93702)

A faulty pressurizer heater was identified during Cycle 2 operation and was successfully replaced during this refueling outage. Another heater had failed during Cycle 1 operation which could not be extracted and replaced. In that case, the heater element had been cut off below the lower support plate and the penetration sealed with a welded plug. The inspector reviewed several Engineering Evaluation Requests (EERs) providing resolution of various concerns as efforts to extract that heater proceeded. EER 88-RC-083 and Site Modification 2-SM-RC-011 document the acceptability of leaving portions of the heater in the pressurizer.

The failure mechanism of the Cycle 1 failed heater, documented in EER 88-RC-123, is similar to that found in Arkansas Unit 2. The heater expands after water intrusion through the heater sheath wets the surrounding magnesium oxide with sufficient force on the inner diameter of the heater sheath to split the sheath. The crack thus formed will propagate in either direction and allow further wetting of the magnesium oxide and further splitting. This could have resulted in an unisolable loss of coolant as the sheath splits into the weld area. In this case, the split extended to about 1/4 inch into the upper end of a sleeve, but no weld area deformation was observed. These conditions were evaluated and determined by the licensee to be satisfactory to support the continued use of the penetration with a welded plug and the remaining portion of the heater in the pressurizer. The inspector noted that the heater sheath remaining in the pressurizer is not in contact with the pressure boundary such that potential for boundary leakage could occur.

No violations of NRC requirements or deviations were identified.

17. Reactor Coolant Pump Breaker Trip - Unit 2 (93702)

On July 12, 1990, while rolling the circulating water pump breaker into the cubicle adjacent to the 1B Reactor Coolant Pump (RCP) breaker, the electricians jarred the side of the cubicle. The vibration caused protective relays on the front of RCP 1B to shift, which tripped the 1B RCP breaker. The reactor was shutdown at the time and there was no operational impact. This event is similar to the April 15, 1990 event in Unit 1 described in Inspection Report 528/90-20, paragraph 14. The inspector noted that the evaluation of this event is not complete and that the only document tracking the evaluation is EER 90-NA-009, which was issued as a result of the April 15, 1990 event at Unit 1 and is still open. The inspector concluded that the corrective action taken as a result of the

Unit 1 event was inadequate to prevent recurrence. The inspector will track the licensee's resolution of EER 90-NA-009 with an Inspector Followup Item (529/90-23-01).

No violations of NRC requirements or deviations were identified.

18. Missed Reactor Coolant System Boron Sample - Unit 2 (93702)

On July 4, 1990, a Reactor Coolant System (RCS) boron sample was not obtained when required. During the RCS heatup with the plant in Mode 3 with charging pump CHA-P01 running, a second charging pump, CHE-P01, was started at 1:22 PM, MST, resulting in an increase in the required RCS boron concentration monitoring frequency, from 6 hours to 2.5 hours, in accordance with Technical Specification (TS) 3.1.2.7.a and Table 3.1-5. A sample had been taken at 1:20 PM and another was required by 3:52 PM. However, another sample was not obtained until 4:20 PM. The sample results confirmed that no unacceptable boron dilution had occurred.

The licensee's investigation of interim corrective actions and actions to prevent recurrence is being documented in Incident Investigation Report (IIR) 3-2-90-026. The licensee will be submitting an LER for this issue and the licensee's corrective actions will be reviewed at that time.

19. Reactor Coolant System (RCS) Spill - Unit 2 (93702)

On July 12, 1990, a 30-gallon RCS spill resulted from an overpressurization of a tygon tube which was used to test the newly installed Refueling Water Level Indication System (RWLIS). The RCS was being pressurized to 100 psia when the tygon tube ruptured. The System Engineer who discovered the source shut valve 2RC-V204 to isolate the RWLIS from the RCS, stopping the spill. The spill was cleaned up promptly. Air samples confirmed no airborne radiological problem developed from the event.

The RWLIS had been recently installed and had not been turned over to operations at the time of the event. In this condition, the operations procedures and plant drawings had not yet been updated to reflect the plant modification.

The licensee is documenting its investigation into this event in Incident Investigation Report (IIR) 3-2-90-017. This investigation will address the apparent programmatic weakness regarding control of the implementation/retest phase of modifications. This issue will be examined by the inspector after the licensee's investigation is complete (529/90-23-02). Other related comments regarding adequacy of system documentation for operations is found in paragraph 14 of this report.

No violations of NRC requirements or deviations were identified.

20. Reactor Power Cutback - Unit 3 (93702)

On May 29, 1990, at 3:56 PM, MST, Unit 3 was at 100 percent reactor power, when the "A" Main Feedwater Pump Turbine (MFWPT) tripped resulting in a Reactor Power Cutback (RPCB). The Reactor Power Cutback caused the selected Control Element Assembly (CEA) regulating groups 4 and 5 to fully insert in the core and setback the Main Turbine to 60 percent, per design. After the insertion of the CEA's and the run back of the Turbine, the CEA's were placed in Manual Sequential control to maintain temperature and to stabilize power in accordance with 43AO-3ZZ43, Reactor Power Cutback (Loss of Feedpump). Power was stabilized at approximately 52 percent.

The event was initiated during calibration of the "A" MFWPT high discharge pressure switches, but was determined by the licensee not to be a human performance deficiency. Troubleshooting indicated that pressure spikes were induced in the pressure sensing lines during instrument valve manipulation. Engineering Evaluation Request EER 90-FT-007 was generated to evaluate the pressure spike phenomena and provide recommendations.

The inspector reviewed the licensee's Incident Investigation Report (IIR) 3-3-90-007 and followed up on several issues not brought to closure in the report. While troubleshooting is still incomplete for two minor problems identified in the report, the licensee's response and corrective actions appear adequate and it appears that the open issues are being prudently addressed.

No violations of NRC requirements or deviations were identified.

21. Cracked Reactor Trip Breaker Arc Chutes - Unit 3 (93702)

While performing semi-annual preventive maintenance on a Westinghouse reactor trip breaker, the electricians discovered damage to two of the three arc chutes. The electricians who initially removed the arc chutes were certain that the chutes were not damaged when the breaker was removed from service, however the foreman has not been able to establish when and how they were damaged. The system engineer told the inspector that the damage is what would be expected if the screws securing the arc chutes were over-tightened. The inspector looked at the damaged arc chutes and agreed with this conclusion. Based on the electricians assurance that the arc chutes were not damaged when the breaker was removed from service, the system engineer concluded that the arc chutes did not fail in service and an evaluation of the damage on the operability of the breaker was not necessary. The inspector concluded that this event suggests a need for better control of maintenance practices for these and similar breakers.

No violations of NRC requirements or deviations were identified.

22. OSHA Concern: Non-ionizing Radiation - Units 1, 2 and 3 (93001)

A licensee contractor raised a concern regarding non-ionizing radiation effects associated with Electro-Magnetic Fields (EMF) on personnel occupying the Unit 2 Operations Support Building (OSB). The inspector passed this concern to the licensee. The licensee asserted that the location of the OSB met OSHA and licensee guidelines for stand off distances from the nearby high voltage lines.

The contractor also questioned the effects of Radio Frequency (RF) radiation on workers in the vicinity of a microwave transmitter. This issue was also passed on to the licensee. The licensee determined that RF power and energy densities were well within ANSI guide lines and that no health hazard exists.

No violations of NRC requirements or deviations were identified.

23. Review of Licensee Event Reports - Units 1, 2 and 3 (92700)

The following LERs were reviewed by the Resident Inspectors.

Unit 1:

a. 528/90-01-L0/L1 (Closed) "Engineered Safety Feature Actuation Caused by Radiation Monitor Spike"

The licensee event discussed in this report was previously discussed in Inspection Report 528/90-03, paragraph 13. This LER is closed.

b. 528/90-03-L0 (Closed) "Inoperability Of All Log Power Channels Places Plant in Condition Not Defined By Technical Specifications"

This licensee event discussed in this report was previously discussed in Inspection Report 528/90-12, paragraph 11. This LER is closed.

c. 528/90-04-L0 (Closed) "Technical Specification Surveillance (TS) Requirement Missed Due To Procedure Error"

This licensee event involved surveillance testing procedures which test the remote shutdown disconnect switch and control circuit operability of Units 1, 2 and 3. However, these procedures did not test the remote shutdown panel control of valve SIB-UV-659. At the

time of discovery this surveillance requirement only applied to Unit 3 since Units 1 and 2 were in operational modes to which this surveillance did not apply. The licensee entered Action (b) of Technical Specification (TS) 3.3.3.5, immediately revised the surveillance procedure, performed the surveillance on valve SIB-UV-659, declared the remote shutdown system operable, and exited Action (b) of TS 3.3.3.5. Procedure changes were issued for Units 1 and 2 and TS component change record entries were made to ensure that completing this surveillance would be a Mode 2 restraint. A 100 percent review of the TS 4.3.3.5.b required equipment was made with the surveillance procedures to ensure that no other components were missed in the surveillance test procedures. This LER is closed.

The inspector concluded that although Technical Specifications requirements had been violated, the licensee's actions were prompt and considered appropriate. Thus, this violation is not being cited because the criteria of Section V.G.1 of the Enforcement Policy were satisfied.

<u>Unit 2:</u>

a. <u>529/89-09-L0/L1 (Closed) "Reactor Trip Due to Partial Loss of Forced Flow"</u>

This LER reports the reactor trip and safety injection which occurred on July 12, 1989. This event was also documented in Inspection Report 529/89-30, Paragraphs 11 and 12. The LER appears to adequately identify the root causes of the plant response problems, though the root cause of failure of the potential transformer fuse failure which resulted in the trip was not conclusively determined due to insufficient data.

The corrective actions and actions to prevent recurrence were reviewed and confirmed to have been implemented. These actions appear to adequately address the known root causes of the event and plant response problems.

Unresolved item 89-30-05, concerning adequacy of previous corrective actions for problems with pressurizer spray valves and steam bypass control valves, is addressed separately in paragraph 2 of this inspection report. This item resulted from the inspectors questions related to these system responses following the reactor trip and which were not addressed in the LER.

This LER is closed.

b. 529/89-10-LO (Closed) "Reactor Trip Due to Erroneous Power Level Signal"

This event was previously inspected and reported in Inspection Report 89-49, Paragraph 10. Three faults resulted in the plant trip: 1) a grounded Reactor Coolant Pump (RCP) speed sensor, 2) a faulty cable connector for excore nuclear instrumentation (NI), and 3) a failed excore NI linear calibrate switch.

The corrective actions described in the LER appear adequate to address the deficiencies and prevent recurrence.

The temporary modification to the NI linear calibrate switch was installed in all three units. Permanent replacement switches have been procured and were installed in Unit 2 during the current refueling outage.

Two preventive maintenance tasks have been developed for the RCP speed sensors for each unit, as described in the LER.

The licensee committed to performing an evaluation of methods to ensure continuity of NI detector cables and associated connectors following maintenance or test activities. According to the Engineering Evaluations Department System Engineer, the evaluation is incomplete. No method has been identified which will check continuity when the reactor is at very low power levels. Work orders are in place to confirm that the signal strength is too weak to detect while the reactor is shutdown. However, continuity can be confirmed at low power levels during reactor startup early enough to identify problems before challenging safety systems. Additionally, channel deviations result in alarms and automatic reactor trips, even if the discontinuities are not detected earlier. The sole purpose of this corrective action was to enable the licensee to repair deficiencies without affecting the plant startup schedule. This is not a safety concern. This LER is closed.

24. Review of Periodic and Special Reports - Units 1, 2 and 3 (90713)

Periodic and special reports submitted by the licensee pursuant to Technical Specifications (TS) 6.9.1 and 6.9.2 were reviewed by the inspector.

This review included the following considerations: the report contained the information required to be reported by NRC requirements; test results and/or supporting information were consistent with design predictions and performance specifications; and the validity of the reported information.

Within the scope of the above, the following reports were reviewed by the inspector.

Unit 1

- o Monthly Operating Report for May and June 1990.

Unit 2

- o Monthly Operating Report for May and June 1990.

Unit 3

- o Monthly Operating Report for May and June 1990.

No violations of NRC requirements or deviations were identified.

25. Exit Meeting (30703)

The inspector met with licensee management representatives periodically during the inspection and held an exit meeting on July 19, 1990. Additionally, a separate exit meeting was held on June 29, 1990, regarding the inspection findings documented in Paragraph 14 of this report.