U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-528/90-45, 50-529/90-45 and 50-530/90-45

Docket Nos. 50-528, 50-529, 50-530

License Nos. NPF-41, NPF-51, 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 & 3

Inspection Conducted: September 30 through November 3, 1990

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

Approved By: Howard J. Wong 12/3/90
H. J. Wong, Chief Date Signed
Reactor Projects Branch, Section II

Inspection Summary:

Inspection on September 30 through November 3, 1990 (Report Numbers 50-528/90-45, 50-529/90-45, and 50-530/90-45)

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors. Areas inspected included: previously identified items; review of plant activities; engineered safety feature system walkdowns; monthly surveillance testing; monthly plant maintenance; splice deficiency identified by system engineer - Unit 1; malfunction and potential loss of as-found conditions of a Potter-Brumfield relay - Unit 1; containment purge isolation - Unit 1; reactor cutback due to main feedwater pump trip - Unit 1; emergency diesel generator trip - Unit 3; reactor trip -- design basis uncertainty - Unit 3; evaluation of licensee self-assessment capability - 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: 30703, 40500, 61726, 62703, 71707, 71710, 92700, 92701, 92702, 92703 and 93702.

Results: Of the 13 areas inspected, 1 violation was identified. The violation pertained to inadequate post-maintenance testing procedures for

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PDR ADOCK 05000528
Q PDR

motor operated butterfly valves in Unit 2, but is applicable to all three units.

General Conclusions and Specific Findings

Significant Safety Matters:	None
Summary of Violations:	1 Cited Violation (Unit 2)
Summary of Deviations:	None
Open Items Summary:	13 items closed, 5 items left open, and 4 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 & Licensing
B. Ballard,	Quality Assurance Director
W. Barley,	Rad. Protection Tech. Svc., (Acting) Manager
H. Bieling,	Emergency Plan/Fire Prevention, Manager
*T. Bradish,	Compliance, Manager
P. Caudill,	Site Services, Director
W. Conway,	Executive Vice President - Nuclear
E. Dotson,	Engineering & Construction, Director
*J. Draper,	SCE, Site Manager
R. Flood,	Plant Manager, Unit 2
*R. Fountain,	QA and Monitoring, Deficiency Coordinator
D. Fuller,	Chemistry, Acting Site Manager
F. Godwin,	Nuclear Records Management, Manager
*K. Hall,	El Paso Electric Co., Site Representative
*R. Henry,	Salt River Project, Site Representative
J. Hesser,	I&C Engineering, Manager
M. Hodge,	Mechanical/Chemical, Manager
P. Hughes,	Site RP, General Manager
*W. Ide,	Plant Manager, Unit 1
*S. Kanter,	Participant Services, Sr. Coordinator
F. Larkin,	Security, Manager
*J. Levine,	Vice President, Nuclear Power Production
*J. LoCicero,	Independent Safety Engineering, Manager
*W. Marsh,	Plant Operations & Maintenance, Director
*J. Napier,	Compliance, Lead
G. Overbeck,	Technical Support, Director
M. Powell,	Nuclear Licensing, Manager
F. Prawlocki,	Engineering Assurance, Manager
W. Quinn,	Nuclear Licensing, Director
G. Shanker,	Commitment Management Project
*T. Shriver,	Assistant Plant Manager, Unit 2
W. Simko,	Maintenance Manager, Unit 2
E. Simpson,	Vice-Pres. Eng. & Const. (Acting Dir. Nuclear Eng. & Support Services)
D. Stover,	Nuclear Safety, Manager (Corp. Assmt. Group)
W. Webster,	Component Engineer, Manager
P. Wiley,	Work Control Manager, Unit 2

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

*Attended the Exit meeting held with NRC Resident Inspectors on November 1, 1990.

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

Unit 1:

a. (Open) Followup Item (528/89-24-P): "10 CFR Part 21 Report and Information Notice 90-03 on BW/IP International, Inc. High Pressure Swing Check Valve Failure" (92701)

The vendor initially reported the failure of one of their check valves at Comanche Peak Steam Electric Station. The Part 21 report indicated that initial investigation of the failed valve showed "no defects or failure to comply." Based on this, the licensee determined no further evaluation was necessary.

The NRC issued Information Notice 90-03 on January 23, 1990, related to the check valve failure. The inspector reviewed licensee memorandum 281-00300-ECS/MFM. APS actions to date include internal inspections of 17 Borg Warner check valves during the most recent Unit 2 refueling outage. No recordable indications were discovered. The licensee plans to continue these inspections as part of their Check Valve Program. Finally, they expect to complete a fracture mechanics analysis and probabilistic risk assessment to determine overall contribution of check valve failure to interfacing system LOCA's during the second quarter of 1991. This item will be reviewed again at that time.

b. (Open) Followup Item (528/89-25-P): "10 CFR Part 21 Report Deficiency With Limitorque SMB-000 and SMB-00 Motor Operator Torque Switches" (92701)

The vendor reported a deficiency with the above torque switches on certain motor operators with specified serial numbers. The licensee initiated EER 89-XE-059 to evaluate this condition for impact on installed motor operators. This item will remain open until the evaluation is complete by the licensee, which is expected by January 1991.

c. (Open) Enforcement Item (528/90-20-02): "Post-Accident Sampling System (PASS) Over-Pressurization" - Unit 1 (92702)

This event involved the overpressurization of the PASS system due to miscommunication leading to a valve misalignment. The procedures have been clarified to reduce the potential for miscommunication and an action plan/schedule has been developed and partially implemented to provide controls for chemistry personnel who manipulate plant equipment. The inspector questioned whether this effort should be expanded to other non-operations department personnel. This item will remain open pending the licensee's response.

d. (Closed) Followup Item (528/90-20-03): "Refueling Water Tank (RWT) Stratification" - Unit 1 (92701)

This item involved an evaluation of the out of specification sample of RWT boric acid concentration and the subsequent Independent Safety Engineering Group (ISEG) evaluation SI-90-04, which followed. Since the ISEG report did not conclude whether stratification occurred or not, Engineering Evaluation Request 90-CH-067 (originally 90-SI-108) was written to request engineering to evaluate the sampling method used to obtain a representative boron sample. The conclusion of the EER was that PVNGS and industry experience suggests that stratification could occur and is best monitored by sampling at both high and low points in the RWT rather than the current practice of only one sample point. This EER was closed and an ICR initiated to change the RWT sampling methodology to sample both high and low points. The inspector concluded that EER 90-CH-067 appears to address this issue and that the ICR appears appropriate. This item is closed.

e. (Closed) Enforcement Item (528/90-28-03): "Incorrectly Set Alarming Dosimeter" - Unit 1 (92702)

This violation was described in paragraph 9 of Inspection Report 528/90-28. The licensee's corrective actions included: issuing a memorandum; revising initial OJT, qualification and continuing training; reevaluating other Radiation Protection (RP) instrumentation for similar concerns; and reevaluating RP clerk tasks which were transferred to RP Technicians. No additional deficiencies were identified. This item is closed.

Unit 2:

a. (Closed) Unresolved Item (529/90-20-01): "Post-Maintenance Retests of Motor Operated Butterfly Valves (MOBVs)" - Unit 2 (92701)

This Unresolved Item resulted from a May 20, 1990, event in which the "A" Essential Cooling Water (EW) system could not be placed in service due to excessive leakage through the EW to Nuclear Cooling (NC) cross-connect valve, 2EQA-UV-145, following performance of maintenance on the valve operator per Work Order (WO) 374572, during which the limit switches were adjusted. The inspector concluded that the retest required by this WO was inadequate in that no seat leakage check or other test was performed to ensure that the butterfly valve was actually closed when it was indicating closed. The failure to specify appropriate acceptance criteria for determining that the maintenance activity was performed satisfactorily is considered to be an example of a violation of NRC requirements (Enforcement Item 529/90-45-01). The inspector noted that WO 374572 also lacked the Retest form required by licensee procedures. Additionally, since WO 374572 referred to procedure 32MT-9ZZ48, "Maintenance of Limitorque Motor Operated

Valves," which did not specify leakage testing requirements, the licensee determined that all MOBVs which had been similarly maintained and retested by this procedure had not been adequately retested, unless other additional retesting had been performed.

After the inspector questioned the implications of the inadequate retest for other MOBVs in safety-related systems, the licensee began an informal review. The licensee also initiated an Instruction Change Request (ICR) to modify procedure 32MT-9ZZ48 to address this deficiency. However, the ICR was never actually submitted because preliminary results from the review of other valves led the licensee to conclude that tests or methods were in place which were sufficient to show that they were functional.

No Quality Deficiency Report (QDR) or other corrective action document was initiated by the licensee to address the procedure inadequacies. Consequently, the review being performed remained informal. Verbal results of the review were provided to the inspector on August 10, but no written or reviewable results were available until September 4, 1990. These results, documented in memorandum 316-00045-WEW/GWW/GI, consisted of a list of 27 MOBVs in safety-related systems and a brief explanation as to how they are or may be confirmed to be reasonably leak tight when closed. No check was made to determine if adequate retests had been performed since the last time the limit switches had been adjusted. Additionally, the position verification methods available were not all identified, in that ASME Section XI procedures containing position verification steps were not included.

The licensee determined that in each unit eleven of the valves are included in the Local Leak Rate Testing (LLRT) program, and are adequately leak tested. Four valves in the suction line from the Containment Recirculation Sump (SIA-UV-673, SIA-UV-674, SIB-UV-675 and SIB-UV-676) are tested in a manner similar to LLRT testing even though they are not included formally in the LLRT program. Potential leakage through four other valves (SIA-UV-657, SIA-UV-678, SIB-UV-658 and SIB-UV-679) could impact effective shutdown cooling control, but not a safety injection function. The inspector questioned the licensee's review of safety significance if the remaining eight valves were not fully closed or fully open when they were so indicated, and what retest had been performed following their most recent maintenance affecting limit switch settings. The licensee then determined that two valves (CTA HV-001 and CTA HV-004) receive positive leak checks as part of Section XI testing.

Of the remaining six MOBV's, the two EW to NC cross connect valves (EWA-UV-145 and EWA-UV-065) are the barrier between the Seismic Category I EW system and the Seismic Category II NC system. They receive no leak tests but are self-revealing when

gross leakage exists. The EW system design leakage rate of 50 gpm, if exceeded, would result in NC and EW surge tank level alarms. Following the operational problems with 2EWA-UV-145 on May 20, the licensee reworked the valve and performed a positive leak check as a retest. The EW "A" train was returned to service on May 22, 1990.

The inspector reviewed recent work activities on the last four valves, the spray pond spray isolation valves (SPA-HV-49A, SPB-HV-50A) and spray bypass valves (SPA-HV-49B, SPB-HV-50B). Work Order (WO) 385099, completed on May 19, 1990, required performance of procedure 32MT-9ZZ48 on 2SPA-HV-49B and resulted in adjusting limit switches for the valve. The specified retest was contained in the procedure, which the licensee had subsequently determined to lack an adequate seat leakage check. However, no additional retest was identified as a result of the final review of the WO completed June 6, 1990, or as a result of the inspectors questions regarding MOBV's in general. The licensee has not yet determined how much leakage is allowable through this valve before the Spray Pond (SP) system would be unable to perform its safety function. The SP system does not have a flow instrument which indicates how much flow is directed to the spray nozzles or the bypass line. WO 385098, completed on May 18, 1990, included maintenance on 2SPA-HV-49A and used the same retest. The failures to specify appropriate acceptance criteria for determining that maintenance on 2SPA-HV-49A and 2SPA-HV-49B was satisfactorily accomplished to assure the design criteria of the system are met are considered to be additional examples of a violation of NRC requirements (Enforcement Item 529/90-45-01). The inspector noted that these maintenance activities occurred at about the same time as the maintenance on 2EWA-UV-145, and that while the EW issues were being addressed, the licensee failed to review the implications for the SP valves. An additional opportunity existed to identify the problem with the SP valve retests during the back-end review of the WOs. ASME Section XI testing was not performed until May 25, 1990, though the SP "A" train was in service on May 22 to support operation of the "A" train of Shutdown Cooling, which was the only train in service. The licensee agreed that the Section XI test should have been done prior to the system being required for operation. The inspector encouraged the licensee to review Section XI testing requirements for system restoration.

In reviewing work history for the SP valves, the inspector found that an ASME Section XI test, contained in procedure 73ST-2XI07, "Section XI Valve Stroke Timing & Position Indication Verification, Mode 1 thru 4-GA, GR, RD, SP and WC," includes a position verification procedure for the four SP valves in question. The verification method is to observe flow from the spray nozzles and bypass line. Step 8.10.4.4.1, "Acceptance Criteria," requires an operator stationed at the spray pond to verify that there is flow through the spray

nozzles and that "there is NO flow present from the Bypass Line, thus verifying SPA-HV-049A is OPEN and SPA-HV-049B is CLOSED." However, the inspector observed that there is no flow instrumentation on the bypass line or the spray line and that the bypass line discharges about 10 feet below water into the spray pond. The inspector concluded that it would be very difficult to detect flow from the bypass line, particularly while water from the spray nozzle caused surface turbulence. Weather conditions could also contribute to reduced ability to monitor flow. After the inspector questioned the basis for signing this step off in the Section XI the Surveillance Test (ST) or if the amount of leakage necessary to result in visual turbulence would result in flow from the spray nozzles below the design requirements, the licensee acknowledged that the intent of Section XI was not met by the existing method, and an ICR was submitted to require local position verification. The absence of appropriate acceptance criteria in procedure 73ST-2XI07 is another example of a violation of NRC requirements (529/90-45-01).

The aforementioned September 4, 1990 memorandum which documented the licensee's review identifies a monthly Preventive Maintenance (PM) activity which provides data for SP system performance monitoring and analysis. This data provides evidence that the current valve leakage is acceptable. However, this PM was not specified as a post-maintenance retest and was not performed following maintenance on 2SPA-HV-49A or -49B prior to the system being operated in support of shutdown cooling.

Procedure 30DP-9WP04, "Maintenance Retest Manual," requires the Test Designator to specify retests to ensure the component is capable of performing its intended function. However, the guidance included in this procedure does not address the type of work performed in 32MT-9ZZ48. The inspector noted that a revision to this procedure is currently being reviewed by the licensee. Additionally, a revision to 30PR-9ZZ04, "Valve Motor Operator Monitoring and Test Program," has also been initiated to include retest requirements for MOBVs.

The safety significance of this issue is embodied in the individual safety function of the valves involved. In some cases, the specific leakage criteria have not yet been determined by the licensee. In some cases, the valves provide isolation between Seismic Category I safety systems and Seismic Category II non-safety systems. Operational problems such as with the EW system, could result. The basic issues are that operators may not be able to rely on valve position indication to represent true valve position, and that system design requirements may be compromised by maintenance activities which lack appropriate retest requirements.

10 CFR Part 50, Appendix B, Criterion V, requires procedures to include appropriate acceptance criteria for determining that

important activities have been satisfactorily accomplished. This requirement appears not to have met in several instances as described in the previous paragraphs.

The inspector concluded that the licensee's review of the status of MOBVs in safety-related systems did not appear to be performed in a timely manner and was not rigorous or complete. The informality of the review was not consistent with the licensee's QDR program, which applied but was not implemented. THe licensee has acknowledged the inspectors concerns and has initiated corrective actions as described previously. Therefore, this unresolved item is closed and further followup will be tracked under Enforcement Item 529/90-45-01.

b. (Open) Followup Item (529/90-23-02): "Thirty Gallon Reactor Coolant System (RCS) Spill" - Unit 2 (92701)

This issue resulted from an RCS spill associated with pressurizing the RCS while a recently installed, but not fully implemented, Refueling Water Level Indication System (RWLIS) was inadvertently aligned to the RCS. The inspector had several questions regarding the conclusion and corrective actions identified in Incident Investigation Report (IIR) 3-2-90-017. Some of the key issues were deferred to corrective action documents Quality Deficiency Report (QDR) 90-309, QDR 90-310, and Corrective Action Report (CAR) 89-0076. These documents have not all been closed. This item will remain open pending licensee closure of the QDRs and CAR.

c. (Open) Followup Item (529/90-28-02): "Plant Monitoring System (PMS) Database Errors" - Units 1, 2 and 3 (92701)

Two examples of data inaccuracies were discussed in NRC Inspection Reports 529/90-28 and 529/90-39. Three additional occurrences of incorrect data in the PMS database have been identified by the licensee. Because of the similar nature of these events, all these issues will be evaluated together. The licensee has initiated an investigation of these issues, which will be documented in Incident Investigation Report (IIR) 3-1-90-046. The three additional occurrences are described below.

(1) On April 23, 1990, with Unit 3 operating at 100 percent power and Units 1 and 2 shutdown for refueling, a licensee engineer identified a discrepancy between the PMS database and the Combustion Engineering (CE) Setpoint Documents (N001-1.01-413, -841, -842 and -843) in the value for the Part Length Control Element Assembly (PLCEA) Lower Group Stop (LGS). Engineering Evaluation Request (EER) 90-RJ-015 documents that the CE Setpoint Document value of 24 inches withdrawn is correct and that the database value of 21.75 inches withdrawn is incorrect. Material Nonconformance Report (MNCR) 90-RJ-0001 was issued on October 1, 1990, to evaluate the acceptability of this

condition. The MNCR documents the determination that operation with this discrepancy was acceptable, but that the database must be corrected. The database had not been corrected as of the end of this inspection period, although work documents were being prepared. Because the database value does not affect the Core Operating Limits Supervisory System (COLSS) or Core Protection Calculators (CPCs), and other restrictions prevent operation with PLCEAs inserted near the LGS setpoint, the inspector concluded no immediate changes were necessary. IIR 3-1-90-043 was also initiated on October 1, 1990, to evaluate the circumstances of this occurrence, and is not yet complete.

(2) On October 5, 1990, with all three units operating at 100 percent, the licensee identified a discrepancy between the PMS database and the CE Setpoint Documents (N001-1.01-413, -841, -842, and -843) for the Control Element Assembly (CEA) Major Group Deviation Limit. The Setpoint Documents contained the correct value of 5.25 inches, whereas the database value was 9.75 inches. MNCR 90-RJ-0002 was issued on October 5, 1990, to evaluate the acceptability of this condition. The MNCR documents the determination that operation with the condition is acceptable, but that the database must be corrected. The database was not corrected as of the end of the report period, although work documents were being prepared. Because the database affects Control Room annunciation only (no control functions), and the Minor Group Deviation Limit provides a more conservative annunciator warning, the inspector concluded no immediate changes were necessary.

(3) On October 17, 1990, with Unit 2 operating at 100 percent power, the licensee identified incorrect sensitivity values in the PMS database. The licensee reduced reactor power to approximately 80 percent power which is consistent with a COLSS inoperable condition. The licensee's analysis, documented in MNCR 90-RJ-0005, determined that the errors had only a negligible effect on the results of COLSS calculations, and the reactor was returned to full power on October 19, 1990. The background regarding this problem is described below.

During the Unit 2 Cycle 3 refueling outage, 42 of 61 incore detector strings were replaced. The vendor requested information from the licensee on the Unit 2 Cycle 2 end of cycle detector sensitivities (So) such that the 19 old string (So) values could be adjusted. The licensee incorrectly sent Unit 1 Cycle 1 data to the vendor representing it as Unit 2 Cycle 1 information, and incorrectly verified the data in two subsequent phone conversations thereby missing opportunities for error identification. The vendor noted that this data was not

the same as had been provided for Unit 2 Cycle 1, and further noted that the data corresponded to Unit 1 Cycle 1 values. The vendor incorrectly assumed that the licensee had used these Unit 1 Cycle 1 values throughout Unit 2 Cycles 1 and 2. This discrepancy was communicated to the licensee in a July 19, 1990, letter from the vendor. The licensee did not act to verify this assumption following receipt of the July 19, 1990 letter. The adjusted values for the old detector strings were determined based on this faulty assumption. Consequently, the adjusted (So) values were incorrect, but certified to be correct by the vendor.

Since reactor startup in July 1990, Unit 2 has had 34 incore detectors fail. The failure rate of Unit 2 incore detectors and the assumption that Unit 1 Cycle 1 data were used in Unit 2 prompted the licensee's Reactor Engineering group to ask the Nuclear Fuel Management group to review possible second order effects on COLSS. It was during this review that the error was identified.

An evaluation of the impact of the incorrectly adjusted (So) values was performed by the licensee. The (So) errors averaged about 2.5 percent, with the maximum error being about 4.5 percent. This error, added to existing variance, results in a total of 67 "failed" detectors. A detector is considered failed if its variance is greater than 10 percent. COLSS can be operable with up to 76 failed detectors as long as detector symmetry requirements are met. However, since only 67 of 305 detectors are affected, computation of COLSS and of computer code reduction of incore detector data for Core Protection Calculation (CPC) monthly checks gives only 1.0 percent maximum errors in Planar Radial Peaking Factors (Fxy) or COLSS output.

The Plant Review Board (PRB) met and discussed this issue on October 19, 1990. IIR 3-1-90-046 was initiated to address the root cause of this event. The PRB decided that if the disposition of MNCR 90-RJ-0005 concludes there is no impact on COLSS operability or Plant Protection System/CPC operability, and no other safety concerns are presented, and if this disposition is independently verified by a specific qualified individual, that Unit 2 could return to 100 percent power. These conditions were met and Unit 2 was subsequently returned to 100 percent power on October 21, 1990. Of note on this event were the missed opportunities to identify the problems in the (So) values earlier than occurred.

3. Review of Plant Activities (71707 and 93702)

a. Unit 1

Unit 1 operated at essentially 100 percent power throughout this report period with the exception of October 2, 1990. On that date a Reactor Power Cutback occurred due to the tripping of the "B" Main Feedwater Pump resulting in a power reduction to about 50 percent, which lasted several hours (see Paragraph 10).

b. Unit 2

Unit 2 operated at essentially 100 percent power throughout this report period with the exception of October 17-21, 1990. During this interval, plant power was reduced to approximately 80 percent following the licensee's discovery that certain Core Operating Limits Supervisory System (COLSS) inputs were inaccurate (see Paragraph 2.c.(3)).

c. Unit 3

Unit 3 began the inspection period in Mode 1 at 100 percent power. On October 20, 1990, the unit tripped on CPC variable overpower due to an inadvertent opening of all in-service (seven) steam bypass control valves as discussed in Paragraph 12. The unit remained in Mode 3 during troubleshooting, entered Mode 2 on October 21, 1990, and Mode 1 later that same day. On October 30, 1990, the "A" EDG tripped during an engine analysis surveillance test due to a faulty vibration switch as discussed in Paragraph 11. The unit ended the inspection period in Mode 1 at 100 percent power.

d. Plant Tours

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

- Auxiliary 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 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 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.

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 Feature System Walkdowns - Units 1, 2 and 3 (71710)

Selected engineered safety feature systems (and systems important to safety) were walked down by the inspectors 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

o Essential Spray Pond System

Unit 2

o Essential Spray Pond System

Unit 3

o Essential Spray Pond System

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 73ST-9CL03	140 Foot Containment Airlock Seal Leak Test
o 36ST-9SB02	Channel "C" PPS Bistable Trip Units Functional Test

Unit 2

Procedure	Description
o 73ST-2XI6	FWIV 132 Section XI Valve Stroke Timing, Partial Stroke Exercise and Position Indication Verification

Unit 3

Procedure	Description
o 36ST-9SB02	PPS Bistable Trip Units Functional Test
o 43ST-3DG01	Diesel Generator "A" Test
o 77ST-3SB12	CEAC No. 2 Functional Test

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 inspectors 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 inspectors verified that reportability for these activities was correct.

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

Unit 1

Description

- o Calibration of Instrument Loop for HPSI Flow to Reactor Coolant Loop "1A"
- o 36MT-9SF15 CEA Coil Traces
- o Emergency Lighting System Preventive Maintenance

Unit 2

Description

- o FWIV-174 Solenoid Valve Replacement
- o ADV-178 Positioner Adjustment
- o Class 1E Voltage Regulator Capacitor Replacement

Unit 3

Description

- o RU-141/142 LED Replacement

7. Splice Deficiency Identified by System Engineer - Unit 1 (92700)

On October 23, 1990, during a pre-job walkdown, a Engineering Evaluation Department System Engineer noticed an apparent deficiency in the insulation for a cable splice for 15GA-HY-184C, a solenoid valve in the Atmospheric Dump Valve (ADV) control system. During construction in 1985, the splice had been insulated with electrical tape instead of heat shrink as required by applicable specifications. Material Nonconformance Report (MNCR) 90-SG-043 was generated to address the deficiency and the proper insulation was applied as a result of the disposition to rework. Four of the eight cabinets in Unit 1 were inspected, with no other deficiencies noted. This is a positive example of the benefit of System Engineers spending time in the field and is encouraged.

No violations of NRC requirements or deviations were identified.

8. Malfunction and Potential Loss of As-Found Conditions of a Potter-Brumfield Relay - Unit 1 (92700)

Following surveillance testing during which Engineered Safeguards Features (ESF) relay K114 failed to completely change state, technicians removed and replaced K114 which is a Potter-Brumfield Model MDR relay with which the licensee has previously experienced significant design problems (See LER 530/89-07). The failed relay was subsequently brought into a shop area and held for System Engineer evaluation. During this time the technicians cycled the relay by connecting it to a power supply and attempted to determine if the failed state was repeatable.

The inspector determined that the technicians had acted upon a request from a System Engineer to determine the state of the failed contacts. The engineer apparently had no intention of cycling the relay and only desired a continuity check across the contacts. The technicians apparently misinterpreted this request as allowing relay energization. The inspector concluded that those involved should have been more sensitive to the preservation of as-found conditions on failed components so that maximum information can be gained from the Root Cause of Failure (RCF) analysis. In this case it was fortuitous that the relay failure mechanism remained even after the cycling.

The inspector discussed these observations with Unit 1 management who acknowledged the comments and agreed that more sensitivity toward as-found conditions was warranted. Subsequently a discussion of this was distributed in a Unit 1 circular.

Due to the historical problems with the Potter-Brumfield MDR relays, the inspector will review the licensee's RCF (EER 90-SA-25) when it is completed (Followup Item 528/90-45-01).

No violations of NRC requirements or deviations were identified.

9. Containment Purge Isolation - Unit 1 (93702)

On October 12, 1990, with the unit in Mode 1 and while the containment was being vented, a Containment Purge Isolation Actuation Signal (CPIAS) in Channel "B" was received, along with a cross-channel trip of Channel "A". This was caused by the loss of power to the containment power access purge high range radiation monitor (RU-38) Remote Indicating Controller (RIC). The licensee quickly confirmed that no actual high radiation condition or unplanned release had occurred by observing all other available radiation parameters and trends associated with the containment. Following these actions, the venting of containment was resumed, and RU-38 was repaired and returned to service on October 15. A Root Cause of Failure Engineering Evaluation Request (RCF EER) was initiated on the replaced power supply.

The inspector concluded that licensee actions in this event were timely and thorough, giving appropriate consideration to the prevention and identification of potential unplanned releases.

No violations of NRC requirements or deviations were identified.

10. Reactor Cutback Due to Main Feedwater Pump Trip - Unit 1 (93702)

On October 2, 1990, at 3:00 AM, (MST), Unit 1 experienced a Reactor Power Cutback (RPC) from 100 percent power due to the "B" Main Feedwater Pump (MFP) tripping. Operators were hanging a clearance to isolate the "B" MFP mini-flow recirculation valve (1FW-FV-2) for maintenance on its pneumatic operator. The valve itself was isolated, but when operators closed an instrument air supply valve, the opposite train "A" MFP mini-flow recirculation valve (1FV-FV-1) failed fully open. The sudden increase in flow through this 12 inch flowpath resulted in a transient in the MFP suction pressure. The "B" MFP tripped on low suction pressure. A turbine setback, a turbine run back and a RPC occurred bringing the reactor to about 52 percent power and the turbine to about 54 percent power. A second turbine run back occurred a few seconds later, due to a perceived imbalance between reactor power and turbine load which caused steam pressure and Reactor Coolant System average temperature to appear to again satisfy the run back criteria. This resulted in turbine output being reduced to about 15 percent, with the Steam Bypass Control System (SBCS) controlling to maintain reactor power nearly constant. Operators took manual remote control of the SBCS and restored the turbine to about 50 percent load.

The licensee determined that operators had closed the instrument air isolation valve for 1FW-FV-1 instead of the isolation for 1FW-FV-2, due to the control air lines being reversed between the two valves and the air distribution manifold during original construction. The licensee checked the same manifolds in Units 2 and 3 but was unable to visually determine if the valves isolate the components their labels indicate.

Following repair of 1FW-FV-2, the "B" MFP was returned to service. Air was restored to 1FW-FV-1, and the unit was returned to 100 percent power at 5:05 PM on October 2, 1990.

Incident Investigation Report (IIR) 3-1-90-042 was initiated to identify any deficiencies associated with the event. The unexpected second turbine run back was identified as abnormal and is attributed to potential calibration deficiencies in the SBCS. This will not be confirmed until the unit is shutdown.

A previous similar event occurred in Unit 2 on December 22, 1988. In that event, described in Inspection Report 529/88-42 (Paragraph 12), a RPC occurred due to inadvertent isolation of control air to the wrong component as a result of air lines being reversed in an air manifold during construction.

After the inspector asked if plans were being made to confirm the proper configuration of other manifolds in the control air system, the licensee began walkdowns of other manifolds in Unit 1 to determine if the non-controlled Field Generated Drawings (FDGs) were accurate. Quality Deficiency Report (QDR) 90-0421 was initiated to address the fact that these drawings are uncontrolled for non-safety related portions of the system.

Material Nonconformance Report (MNCR) 90-IA-0003 was also initiated and validated, requiring verification of the instrument air lines from the manifolds to the air loads. Licensee management confirmed that this verification would be performed. The inspector concluded that licensee actions with respect to this event were adequate.

No violations of NRC requirements or deviations were identified.

11. Emergency Diesel Generator Trip - Unit 3 (92700)

On October 30, 1990, the "A" Emergency Diesel Generator tripped, apparently on high vibration, due to a faulty Amot Controls Vibro-guard vibration switch. The exact cause of the trip could not be determined because the local diesel panel alarm was reset without noting the first-out indication. During the event the output breaker did not trip due to a faulty Agastat relay coil. This caused the generator to be motorized for approximately 8 seconds because the trip signal caused the fuel racks to trip and the field to short. The control room operator noticed that output megawatts dropped to zero while the output breaker was still closed and manually tripped the generator. The inspector considers this an alert response to protect safety-related equipment.

Troubleshooting identified the faulty vibration switch and relay. The diesel was repaired and returned to operability within the 72 hour action statement time limit. The licensee is pursuing a root cause of failure under Engineering Evaluation Request 90-DG-073 to include analysis of both the relay and vibration switch failures. The licensee also initiated a Problem Resolution Sheet (PRS) to evaluate the trip and subsequent troubleshooting/repair activities. The NRC Electrical Distribution System Functional Inspection Team is investigating the relay failures and will document the results in Inspection Report 530/90-42. The inspector concluded that the loss of the first-out indication complicated troubleshooting and root cause of failure analysis. The licensee acknowledged the inspector's comments.

No violations of NRC requirements or deviations were identified.

12. Reactor Trip -- Design Basis Uncertainty - Unit 3 (93702)

On October 20, 1990, the unit tripped on Variable Overpower (VOPT) at 110 percent power as a result of seven Steam Bypass Control Valves (SBCVs) modulating open. Troubleshooting identified the fault as a shorted blocking diode in the power distribution card for nest 1 in Foxboro cabinet 3J-ZJN-C02E, which contained main steam

pressure channel modules. Repairs included replacing the failed power distribution card and retesting the system. The post-trip review determined that no safety limits were reached. The restart authorization was completed on October 21, 1990, and the unit started up on October 21, 1990.

The shorted diode in the power distribution network shorted the +15 VDC power supply line to ground for the entire Foxboro cabinet, bringing the voltage to essentially zero for all components connected to the power supply line in the cabinet. When the protective fuse blew, the +15 VDC power supply line quickly returned to +15 VDC. This rapid power supply swing caused main steam pressure modules SGN-PY-1024 and SGN-PY-1027 in nest 6 of this Foxboro cabinet to generate a rapidly rising steam pressure signal. This steam pressure signal is one input to the Steam Bypass Control System (SBCS) and its rapid rise caused the SBCS to modulate the seven in-service SBCVs open. In essence, the shorted diode caused a power supply perturbation, causing an affected steam pressure module to generate an erroneous rapidly rising steam pressure signal. The SBCS then responded correctly to the erroneous signal by modulating the in-service SBCVs open. The core protection calculators generated a VOPT as expected. With the exception of the shorted diode, all systems responded as designed.

One element of the post-trip review was to have Nuclear Engineering evaluate the Foxboro cabinet to determine if a plant change would be appropriate to prevent recurrence. During the preliminary investigation, Nuclear Engineering identified an unanalyzed condition. Updated Final Safety Analysis Report (UFSAR), Paragraph 10.4.4.1.2 states that "Power generation design bases applicable to the turbine bypass system are as follows: ... J. Include redundancy in the design so that neither a single component failure nor a single operator error result in excessive steam releases." Excessive steam release as reflected in design analyses is more than one SBCV inadvertently opening.

Since the inadvertent opening of more than one SBCV was not considered a credible Anticipated Operational Occurrence (AOO), no analysis had originally been performed to determine whether General Design Criteria 20 (GDC 20) would be met and Specified Acceptable Fuel Design Limits (SAFDLs) would not be exceeded as a result of this occurrence. In addition, the single failure considered in Table 15.0-0 in the UFSAR accident analysis was excessive SBCS steam demand due to the inadvertent opening of only one SBCV. The licensee's post trip review and restart authorization process failed to recognize the inadvertent opening of more than one SBCV as potentially an unanalyzed AOO. Upon identification of this concern, the licensee placed a continuous, dedicated watch in the control room of each unit to monitor the SBCVs for inadvertent opening while evaluations were performed.

On October 23, 1990, the Plant Review Board (PRB) reviewed this event and determined that no unreviewed safety question (USQ) existed. This decision was documented in a letter dated October 24, 1990, from the licensee to the NRC. The letter also detailed the reasons for their decision to continue to operate while they completed the additional analyses to support a formal Justification for Continued Operation (JCO). On October 25, 1990, a conference call was held between members of the licensee, CE, NRR, RV and the Resident Inspector to discuss the problem and actions taken and planned to resolve the issue. A JCO was submitted to the NRC in a letter dated November 1, 1990 which described the analysis of the event of all SBCVs opening at full power and that fuel design limits were met. In addition, the JCO stated that an evaluation of UFSAR Chapter 15 events potentially affected would be completed by November 23, 1990. The NRC also questioned the basis of the PRB's conclusion that an unreviewed safety question did not exist. The licensee agreed to document the basis of the PRB conclusion for NRC review. Pending the completion of the licensee's evaluation of the event and documentation of the PRB conclusion, this matter will remain open (Unresolved Item 530/90-45-01).

Licensee Event Report 528/86-53 for a reactor trip event which occurred on September 11, 1986, describes a similar event in which eight steam bypass control valves opened while the unit was at 100 percent power due to an electrical short which interrupted all main steam flow signals to the SBCS. The incident investigation report concluded that this event did not pose a safety concern because the event is bounded by the Main Steam Line Break (MSLB) accident analysis. However, since the inadvertent opening of multiple SBCVs should have been considered an AOO, it should also have been demonstrated to meet the more restrictive requirements of GDC 20.

Two other similar events occurred on January 9, 1986, and March 3, 1989, in which inadvertent opening of multiple SBCVs occurred. The inspector concluded that these events were also not adequately evaluated as potential AOO's.

The Unit 3 restart authorization which was prepared on October 21, 1990, did not document an evaluation of UFSAR analysis or design basis. Discussions with individuals associated with the decision to restart the Unit indicated that the UFSAR MSLB accident analysis was considered as the bounding scenario for this event. The Plant Manager recognized the need for additional engineering evaluation associated with the design criteria/safety analysis and tasked the Shift Technical Advisor and System Engineering for later evaluation. The inspector concluded that the existence of the prior events, the recognized need for additional engineering evaluation, and the failure to evaluate the implications of GDC 20 suggests the need for a clearer understanding of plant event characteristics with respect to the plant design basis prior to unit restart.

In addition, the inspector noted that during the event, a page was missing from all copies of the Critical Safety Function Status Checks, Appendix BB of Procedure 43EP-3ZZ01. This identical page was also missing during an April 14, 1990 Unit 3 reactor trip event. The licensee's Incident Investigation Report 2-3-90-002 of the October 20 trip event acknowledges this fact and concludes that the corrective action following the April 14 trip event was not completed. It was to consist of a correction to 43EP-3ZZ01, but was initiated verbally and therefore was not tracked to closure. The licensee issued QDR 90-0437 to resolve the deficiency. The inspector noted that early in 1990, the licensee had stopped tracking IIR action items as a separate category, allowing each item to be tracked by the appropriate corrective action system (i.e. ICR, QDR, MNCR, etc). QDR 90-0437 notes that the licensee's IIR procedures require an Instruction Change Request (ICR) for resolution of procedural problems and that one was not submitted following the April 14 trip event. The inspector concluded that the lack of central control and tracking of IIR open items requires strict adherence to the corrective action provisions of the IIR procedures, and that this did not occur following the April 14 trip event. However, the licensee stated they are evaluating the need for better tracking methods for IIR items.

The inspector concluded that the licensee's existing procedure, if strictly adhered to, adequately provides for tracking corrective action, but encouraged evaluation of methods which would further ensure timely closure of IIR action items. The inspector also noted that IIR 2-3-90-002 incorrectly specified the same ICR number for correcting the Appendix BB discrepancy as well as to include more guidance on when a Nuclear Safety Assessment is required within the IIR procedure. This kind of administrative error can also lead to incomplete corrective action. The inspector also noted that a documented QA review of the IIR failed to note this error. Because the licensee had not determined the extent of changes needed to the IIR procedure the inspector will review these changes when complete (Followup Item 530/90-45-02).

13. Evaluation of Licensee Self-Assessment Capability - Units 1, 2, and 3 (40500)

The inspector used two criteria primarily to evaluate the effectiveness of each group reviewed - (1) whether the group has found problems and provided recommendations which made a contribution to nuclear safety, and (2) where appropriate, whether Technical Specifications (TS) requirements for the number and qualification of the members of the review group were met. Four groups were evaluated, the Nuclear Safety Group (NSG), the Independent Safety Engineering Group (ISEG or ISE), the Offsite Safety Review Committee (OSRC) and the Project Self Assessment Group (PSAG). The Plant Review Board (PRB) was not evaluated in this inspection because it was evaluated in Inspection Reports 528/90-15 and 528/90-37 and because the PRB has recently undergone significant changes which have not been in effect long enough to be meaningfully evaluated.

NSG - Inspection Report 528/89-43 noted weakness in the NSG programmatic review and critique, which could limit beneficial long term organizational changes, and that NSG had not always been effective in accomplishing such change. It appears that NSG took this criticism seriously. NSG conducted more than twelve programmatic reviews with significant recommendations which the inspector considered appropriate. The annual assessment of the PRB was part of the effort to revise the PRB's composition and program which required a TS change to implement. The annual assessment of the 10 CFR 50.59 program resulted in program and training changes which the inspector considers an improvement to the program.

One area in which the inspector had discussions with licensee personnel involved the way technical reviews are trended. The method used to trend the "Personnel Adherence to Administrative Controls" issue was to keep a desk folder of copies of documents which represented issues of this nature. When enough (unspecified) documents were accumulated, the issue was raised to the PSAG and ultimately included as a major issue for the PSAG Semiannual Report to Senior Management. This informal trending approach can be effective, but may not identify all or even the most significant issues. The licensee responded by requiring all NSG members to enter all NSG issues into the NSG database to facilitate broader trending.

The inspector concluded that the NSG has improved over the past year. While some minor faults were identified, the NSG is finding problems and making recommendations which appear to be contributing to nuclear safety improvements.

ISEG - The ISEG has maintained the TS required staffing level during the past year primarily by including contract engineers to augment licensee employees. A large turnover in the ISEG staff has contributed heavily toward this approach. The inspector noted that this can make continuity of tracking and resolving ISEG issues more difficult. The licensee responded by pointing out that turnover of information did occur and that many ISEG evaluations were done by two engineers together.

Inspection Report 528/90-20 addressed inspector concerns with Special Investigation (SI) 90-04. The inspector noted a weakness in that the ISE report did not bring the technical issues to full resolution, instead passing the technical evaluation to the Site Engineering Evaluations Department (EED). Further, the ISE report failed to account for an applicable Technical Specification basis in their discussion. The final resolution of this issue was determined by EED and is noted in this report as closure of Followup Item 528/90-20-03. The inspector noted during this review that the technical resolution of the EER was also within the capability of ISE to have completed.

Field Evaluation (FE) 89-25, "ISE Evaluation of Maintenance Activities," was performed by observing work at Units 1 and 3 on the main feed pump turbine torque shaft and bearing and by reviewing QDRs and other documents associated with maintenance activities. ISE did not observe maintenance activities on nuclear safety-related components to perform this evaluation. However, the licensee stated that another evaluation, FE 89-10, "Diesel Generator Task Evaluation," was also utilized to draw conclusions. The inspector noted that Field Evaluation 89-10 was not focused on maintenance, although it did cover some maintenance activities. The inspector considered the observation of non-quality related maintenance to provide a weak basis for drawing overall conclusions regarding quality related maintenance. While several conclusions address individual worker performance, work practices and consistent work performance between units, ISE made no recommendations for either the Maintenance or Work Control Departments. Instead, conclusions and recommendations were passed to the Maintenance Task Force.

The inspector noted that ISE completed 35 reports since October 1989. Fourteen of these reports had no recommendations. The inspector also noted that of the 25 reports ISEG initiated since October 1989, 11 were the result of external requests. Eight of these resulting from external requests had no explicit recommendations. The inspector acknowledged that some of ISE's reports which had no recommendations found problems which were ultimately addressed, but the inspector still considers it important for ISE to clearly make detailed recommendations as required by TS 6.2.3. The licensee responded by stating that future ISEG reports will include findings in the conclusion and recommendation sections of ISEG reports. The licensee also pointed out that 5 of the 11 externally requested evaluations were initiated by the Vice President of Nuclear Safety and Licensing, who they consider to be part of ISEG. The inspector concluded that it appeared that a significant number of ISE reports resulted in no direct recommendations, and therefore encouraged licensee management to consider better ways to employ ISE resources so as to find more problems and make more recommendations for improvements.

ISE performed FE 90-06, "Reduced RCS Inventory Operation in Unit 1," to comply with the licensee's commitment in their response to Generic Letter 88-17. This commitment required ISEG to review the issue of RCS perturbations after experience has been gained with the new procedural controls. ISEG FE 90-06 reviewed the licensee's commitments and documents associated with mid-loop operation and identified five items which initially did not have documented closure prior to entering mid-loop operations with fuel in the vessel. These items were addressed by plant management. ISE made recommendations to the Manager of Nuclear Licensing to address commitments and commitment tracking. ISE FE 90-06 states that ISE concluded that "There was no impact on nuclear safety with the actions taken in respect to the Unit 1 preparations. ...Based upon this conclusion, ISE determined that entry into Reduced RCS Inventory (Mid-Loop) Operations was justified." The inspector

questioned the appropriateness of an ISEG activity which is an in-line review requiring ISEG concurrence prior to a unit proceeding with critical-path outage work. The inspector acknowledged that ISEG had more engineers than required by TS while this evaluation was being performed and that the licensee may utilize these additional individuals to perform activities which may not be consistent with the concept of ISEG as described in the TS or other source documents (NUREG-0737, etc.). The inspector encouraged the licensee to carefully consider the potential conflict to the principle of independence when tasking ISE to perform in-line reviews.

The inspector finally concluded that ISE has made some improvement during the past year. This is based on the fact that there was only one ISEG report the NRC criticized from a technical basis since October 1, 1989. The inspector noted that ISEG reports were somewhat more consistent in format. The inspector also noted that ISEG engineers made a more visible presence in the field than they had in the past. The inspector encouraged the licensee to continue to improve the definition of ISEG activities, the format and consistency of ISEG reports and the technical accuracy of ISEG investigations.

OSRC - The OSRC is not a TS required organization, but was initiated by the licensee. The inspector attended one OSRC meeting on September 5, 1990. This meeting was a self-critique and not a routine OSRC meeting. Since OSRC has only recently been instituted and was still operating under a draft charter, the inspector concluded that OSRC has not been in existence long enough to allow a meaningful evaluation.

PSAG - The PSAG also is a licensee initiative which is not required by TS. The inspector noted the PSAG's mission is two-fold. First, the PSAG is to identify the areas where oversight is needed and coordinate the planned activities of the groups in the PSAG (QA, NSG, ISEG and PRB) to cover these areas. Second, the PSAG collects the results of all of these oversight activities and attempts to identify common threads, possibly identifying nuclear safety concerns which would not be apparent solely from the results of one individual oversight group. The inspector reviewed the PSAG meeting minutes of 1989, the first Semiannual PSAG Assessment Report, the integrated schedule, and interviewed several members. The inspector concluded that the second aspect of PSAG's mission, as evidenced by the Semi-Annual PSAG Assessment Report, appears to have been accomplished.

The licensee's process for attempting to accomplish the first aspect of the PSAG mission has changed throughout the year. Initially, a PSAG sub-group (made up of subordinates of each PSAG member) was tasked to prepare the integrated schedule which coordinates the planned activities of the member groups. This process did not initially meet the expectations of the PSAG and the schedule responsibility eventually was taken over by the PSAG chairman. The

integrated schedule development as yet does not show a clear coordination effort nor does it appear to systematically ensure that all identified nuclear safety review areas are being covered. The inspector concluded that this process still appears to be developing. The PSAG Chairman agreed and stated that the integrated schedule development process has evolved to the point where it will begin to produce benefits to the licensee. The inspector will evaluate this area again during the normal inspection process. The inspector further concluded that the PSAG process is producing benefits now and has the potential for greater benefits as both aspects of the PSAG process mature.

Conclusion

APS management has numerous self-assessment activities available to identify and help correct nuclear safety issues. Each of the groups evaluated have identified a number of concerns. As the newly reorganized PRB and the newly created OSRC mature, the number of concerns raised may compete for resources. PSAG appears to have the potential to provide this prioritization of resource expenditure. As originally discussed in Inspection Report 528/89-43, independent contractor expertise continues to be utilized by the licensee in various oversight functions, potentially giving rise to organizational instability. Groups required by Technical Specifications appear to be meeting minimum requirements. NSG has shown the most improvement over the past year. The ISEG role still appears to lack clear definition, particularly with regard to the meaning of independent review. The inspector also concluded that ISEG could more consistently provide detailed recommendations to address their findings.

No violations of NRC requirements or deviations were identified.

14. Review of Licensee Event Reports - Units 1, 2 and 3 (90712 and 92700)

The following LERs were reviewed by the Resident Inspectors.

Unit 3

a. 530/89-01-L1/L2/L3 (Closed) "Reactor Trip Due to Low Steam Generator Level" - Unit 3 (92700)

This event was reviewed by an Augumented Inspection Team as documented in Inspection Report 530/89-13. The licensee response to this report and other correspondence between the licensee and NRC Region V documented activities and schedules for the licensee to complete both prior to and subsequent to the restart of the unit. Confirmatory Action Letters (CAL) were issued on March 28, 1989, and June 28, 1990, to document the agreement between the licensee and the NRC that the unit would not be restarted prior to the completion of these activities. A December 24, 1990, letter from APS to the NRC certified that all agreed pre-restart activities were complete.

The CALs were lifted on December 24, 1990. The resident inspectors sampled the closure packages for these pre-restart items as documented in Inspection Report 530/89-54. The LER corrective action to revise procedures for recovering from a Safety Injection System actuation were reviewed by the inspector and contain guidance for performing the previously missed surveillance in a timely manner. LERs 528/89-012 and 528/89-005 document additional corrective action associated with emergency lighting and atmospheric dump valves. Corrective actions associated with these two LERs will be reviewed by NRC inspectors at a later date. Based on NRC inspections of this event, a sampling of the restart items, APS certification of the completion of all restart items, the planned reviews of LERs 528/89-005 and 528/89-012, and the inspector's review of the Safety Injection System actuation recovery procedures. This LER is closed.

b. 530/89-04-L2/L3 (Closed) "Emergency Diesel Generator Rocker Arm Failure/ESF Actuation" - Unit 3 (92700)

This event was discussed in detail in paragraph 13 of Inspection Report 530/88-41 and in paragraph 23 of Inspection Report 530/89-36. The root cause of the rocker arm failure was inadequate design coupled with insufficient inspection. The LER states that "As designed the rocker arm casting was not sufficiently strong to withstand the stress incurred when the push rod seat insert was press-fit into place. This excessive stress resulted in the cracks which then went undetected during post-manufacturing inspections." Cooper-Bessemer has redesigned the rocker arm utilizing an adhesive to affix the push rod insert in place rather than the previously used press-fit method and has instituted additional quality controls. APS has implemented nondestructive examination for replacement rocker arms prior to installation. The steam generator low pressure trip setpoint reduction circuitry problem was addressed by a modification which has installed improved variable setpoint cards in all three units. This LER is closed.

c. 530/89-08-L1/L2/L3 (Closed) "Surveillance Requirements Not Performed Satisfactorily" - Unit 3 (92700)

This event involved the identification of a sixth trip lever arm on the ten ton fuel handling crane rails contrary to the plant design. This sixth trip lever arm could trip the train control starwheel a sixth time permitting the crane trolley/hook to travel over the spent fuel pool in the container mode which allows up to 5,000 lbs load contrary to the surveillance requirement of Technical Specification 4.9.7. The crane was moved away from the spent fuel pool and declared inoperable. The sixth trip lever arm was removed. Units 1 and 2 were evaluated and found to be in accordance with the plant design. An investigation revealed that a DCP may have been

misunderstood resulting in the installation of the sixth trip lever arm. Since the DCP implementation, no work orders were found associated with installation or adjustment of trip lever arms at Unit 3. The inspector concluded that corrective action appeared appropriate. This LER is closed.

d. 530/90-04-LO (Closed) "Reactor Trip Due to Dropped Shutdown Group CEA" - Unit 3 (92700)

This event was discussed in paragraph 19 of Inspection Report 530/90-12. This LER is closed.

e. 530/90-06-LO (Closed) "Plant Shutdown Forced by Slipped Control Element Assembly" - Unit 3 (92700)

This event was discussed in paragraph 15 of Inspection Report 530/90-28. This LER is closed.

15. Exit Meeting

The inspector met with licensee management representatives periodically during the inspection and held an exit meeting on November 1, 1990.