U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-528/90-54, 50-529/90-54 and 50-530/90-54

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: December 2, 1990 through January 5, 1991

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

Approved By: Howard J. Wong 2/15/91
H. J. Wong, Chief Date Signed
Reactor Projects Branch, Section II

Inspection Summary:

Inspection on December 2, 1990 through January 5, 1991 (Report Numbers 50-528/90-54, 50-529/90-54, and 50-530/90-54)

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors. Areas inspected included: previously identified items; review of plant activities; monthly surveillance testing; monthly plant maintenance; inadvertent dilution of reactor coolant system boron concentration - Unit 1; diesel generator operability - Unit 1; turbine driven auxiliary feedwater (AFW) pump oil levels - Units 1 and 3; closure of one of four main steam isolation valves (MSIV) while at 100 percent power - Unit 2; use of improper fuses in safety-related applications - Units 1, 2, and 3; and review of licensee event reports - Units 1, 2, and 3.

During this inspection the following Inspection Procedures were utilized: 61726, 62703, 71707, 92700, 92701, 92702, and 93702.

Results: Of the 10 areas inspected, 1 violation was identified in Unit 1. The violation pertained to a licensee-identified inadequate procedure to place a new letdown ion exchanger resin bed into service.

General Conclusions and Specific Findings

Significant Safety Matters:	None
Summary of Violations:	1 Violation (Unit 1) regarding an inadequate procedure
Summary of Deviations:	None
Open Items Summary:	14 items closed, 1 item left open, and 3 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
*T. Bradish,	Compliance, Manager
*E. Dotson,	Engineering & Construction, Site Director
*R. Flood,	Plant Manager, Unit 2
*R. Fullmer,	QA and Monitoring, Manager
*D. Gouge,	Plant Support, Manager (Ch. Plant Review Bd.)
*S. Guthrie,	QA, Dep. Director
*K. Hall,	El Paso Electric Co., Site Representative
*R. Henry,	Salt River Project, Site Representative
P. Hughes,	Site Rad. Protection, General Manager
*W. Ide,	Plant Manager, Unit 1
F. Larkin,	Security, Manager
*J. Levine,	Vice President, Nuclear Power Production
*J. Minnicks,	Maintenance Manager, Unit 3
*G. Overbeck,	Technical Support, Director
*R. Rogalski,	QA, Supervisor
*J. Scott,	Operations Manager, Unit 1
*S. Terrigino,	Management Services, Supervisor

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 January 8, 1991.

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

a. Unit 1:

1. (Closed) Enforcement Item (528/89-56-02): "Motor Operated Valve (MOV) Database Document Inappropriate" - Unit 1 (92702)

This violation consisted of two examples in which the MOV database document, 13J-ZZI-004, was found to be inappropriate. The first example concerned a technician who selected incorrect switch settings from 13J-ZZI-004, apparently due to confusion resulting from 34 Drawing Change Notices (DCNs) which had not been incorporated. The licensee has since determined that the values selected were actually correct and that none of the outstanding DCNs were applicable to the valve in question. However, the licensee recognized that confusion could result in errors and has developed unit-specific database documents and

has implemented administrative controls to keep them more current.

The inspector reviewed these documents (1J-ZZI-004, 2J-ZZI-004, and 3J-ZZI-004) and found them to be updated in accordance with the administrative controls. The administrative controls require future DCNs related to implemented changes to be incorporated such that none is over six months old and no more than five of these implemented change DCNs exists at a time. These actions appear adequate.

The second example concerned the lack of review and approval documentation to support the calculations for the setpoints in 13J-ZZI-004. The licensee stated that the calculations and appropriate review and approval documentation does exist. The inspector reviewed the documentation supporting the 13J-ZZI-004 setpoints for the following ten safety-related valves:

1J-AFC-HV0033
1J-SIA-HV0698
1J-SIA-HV0666
1J-SIB-HV0676
1J-SIA-HV0684
1J-SPA-HV0049B
1J-EWA-UV0145
1J-AFA-HV0054
3J-SIB-HV0689
2J-CHB-HV0530

While the information was not readily available or well organized, the licensee was able to produce the required documentation, including review and approvals, for the opening and closing thrust minimum and maximum values for all these valves, as appropriate (some valves open and close based on limit switch position and do not have thrust values in the database). Procedure 73PR-9ZZ04, "Valve Motor Operator Monitoring and Test Program," specifies the default settings and methodology for determining limit switch settings. The limit switch settings appeared consistent with this procedure. The licensee is taking steps to better organize the calculations which preceded the Generic Letter 89-10 program. The inspector also noted that several of the calculations have been superseded by new calculations resulting from the partial implementation of the Generic Letter 89-10 program. These actions appear adequate. This item is closed.

2. <u>(Closed) Enforcement Item (528/89-56-10): "Inadequate Corrective Actions for 10 CFR Part 21 Notification on Limitorque Motor Insulation and Technical Manual Deficiency" - Unit 1 (92702)</u>

This violation was presented in two examples of inadequate corrective actions, the first dealing with a 10 CFR Part 21

Notification and the second dealing with the response to Information Notice 85-22.

The licensee disagreed that the first example represented a violation because the facts presented, while accurate, do not constitute a violation of regulatory requirements. The violation concerned failure of the licensee to address both Type SMB and Type SB Limitorque operators in its evaluation, even though the 10 CFR Part 21 notification had only specified Type SMB operators as having the potential problem. The inspector reviewed Engineering Action Requests (EARs) 89-0448 and 89-0449, and Engineering Evaluation Request (EER) 88-XE-015, and confirmed that, consistent with the licensee's response, EER 88-XE-015 addressed the 10 CFR Part 21 Notification applicability to both Type SMB and Type SB Limitorque operators. The inspector concluded that the licensee's response to the violation was accurate and that this example does not constitute a violation.

The second example resulted from a technical manual not being updated following the licensee's response to Information Notice 85-22. The licensee determined that technical manual J605-162 was the only manual not updated. This manual has subsequently been updated and issued. Additionally, the licensee's Vendor Technical Manual project, expected to be complete by December 31, 1993, appears to include in its scope the types of deficiencies identified in this and other findings related to technical manuals. These corrective actions appear to be adequate. This item is closed.

3. <u>(Closed) Followup Item (528/90-03-02): "Load Shed Potential Transformer Failure" - Unit 1 (92701)</u>

This item involved a load shed of a 13.8KV bus, NAN-S02, due to a failure of the potential transformer across the "B" to "C" phase of the bus. A similar failure occurred on the NAN-S01 bus "A" to "B" potential transformer shortly before this event. The licensee conducted a root cause of failure via Engineering Evaluation Request (EER) 90-NA-002. The cause of failure was determined by General Electric to be internal turn-to-turn shorting of unknown origin. An APS Nuclear Engineering failure rate analysis concluded that the mean failure rate for this type device is 6.14E-7 which is close to the industry failure rates represented by the IEEE Reliability Data. The inspector concluded that these results appear appropriate. This item is closed.

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

This event involved damage to the Fuel Building rollup door as a result of improper control of the installation of pneumatic jumpers. Engineering Evaluation Request (EER) 90-ZF-009 was initiated as a result of this event. EER 90-ZF-009 is still

open. This item will remain open until EER 90-ZF-009 is closed and reviewed by the inspector.

5. (Closed) Followup Item (528/90-23-02): "Review of Historically Waived Preventive Maintenance (PM) Tasks" - Unit 1 (92701)

This item involved a review of the licensee commitment to ensure that there are no PM tasks which had been waived which could affect safe plant operation. A significant number of PM review forms were found to contain inadequate documentation for the conclusion reached. The licensee committed to repeating the review, identifying those which were inadequately documented, and providing adequate documentation where needed. In addition, the licensee committed to notifying the inspector of any additional concerns or PM requirements identified during this re-review. No additional concerns were identified by the licensee. The licensee completed the re-review as committed. The inspector reviewed about 10% of the approximately 2000 PM task review sheets and had no concerns with the additional documentation. This item is closed.

6. (Closed) Enforcement Item (528/90-23-03): "Improper Operation of an Atmospheric Dump Valve (ADV) in Manual" - Unit 1 (92701)

This item involved the failure to correctly follow a procedure which resulted in the manual mis-operation of ADV SGB-HV-178, while under the supervision of a more experienced Auxiliary Operator (AO) and a licensed Senior Reactor Operator (SRO). The licensee's System Engineer evaluated the mis-operation and concluded that no damage had occurred. The licensee sampled the knowledge and ability of several AOs at all three units and determined that the AOs knew how to properly operate the ADVs manually and this issue was not a training concern. A Human Performance Evaluation System report was completed which concluded that: (1) inadequate work practices caused the event, (2) the newly qualified AO was under stress due to the presence of the NRC Inspector, (3) having two actions combined into one step was a contributing factor to the mis-operation of the ADV, and (4) a thumbscrew would eliminate the need for the AO to use a tool which could be dropped - not a contributing factor, but identified during the investigation. The licensee counseled and reexamined the AO who mis-operated the ADV and verified that this task could be properly performed. In addition, Instruction Change Request (ICR) 11033 was written to have the tightening of the setscrew made a separate step in procedure 4XOP-XOP01, "Manual Operation of Air Operated Valves," and a plant change request was issued to replace the setscrews with thumbscrews. This item is closed.

7. (Closed) Followup Item (528/90-23-04): "Operating Procedures Review for Independent Verification Requirements - Unit 1 (92701)

This item was associated with Enforcement Item 528/89-16-03, which was closed in Inspection Report 528/90-23. The enforcement item was closed by evaluating the licensee's commitment to review operating procedures "...for human factors considerations, locked valve and breaker requirements, and the new independent verification requirements." The inspector noted that this procedure review initiative went well beyond the scope of the violation. However, the January 2, 1996, scheduled completion date seemed not to be timely, particularly with respect to independent verification requirements. In addition, Enforcement Item 530/89-56-01 noted further independent verification weaknesses and is reviewed in Paragraph 2.C.1. of this report. This Notice of Violation included a commitment to revise "...applicable Operations procedures to include sign off steps to document independent verification" by September 2, 1991. This action will be more timely and will also address the independent verification questions associated with this Followup Item. This item is closed.

8. (Closed) Followup Item (528/90-28-02): "Damaged Reactor Trip Breaker" - Unit 1 (92701)

This item involved the unexpected operating characteristics and subsequent damage to a reactor trip breaker while racking it in and out. The Root Cause of Failure Engineering Evaluation Request (EER) 90-SB-046 was completed on December 21, 1990. This EER concluded that a slightly bent or misaligned closing spring discharge linkage was the most likely root cause of failure. Secondary damage during removal hampered a complete understanding of the root cause of failure. Corrective action included replacing the breaker, routing this EER to Training for all Operations Department personnel, and the issuance of Instruction Change Request 25254 to eliminate unnecessary breaker racking operations. The training on EER 90-SB-046 will be for people who rack breakers to be alert for any abnormal, off-normal or unusual condition and to determine the cause of the anomalous condition before proceeding. This item is closed.

9. (Closed) Followup Item (528/90-39-02): "Technical Support Center (TSC) Batteries Not Charged Properly" - Unit 1 (92701)

The inspector noted specific gravity problems with the TSC diesel generator batteries that were noted but not addressed in Employee Concerns File 89-104-12. Based on the inspector's questions, the licensee then supplemented the existing file to address these comments. The supplement reflected an expanded look at TSC battery preventive maintenance (PM) tasks. This expanded look resulted in Quality Deficiency Report (QDR)

90-0440 which documented a negative trend in the performance of PM tasks on these batteries, which are non-safety related. Problems noted included personnel not identifying, documenting, or reporting problems, and making administrative and calculation errors while performing PM tasks on TSC batteries. In addition, examples were noted in which Work Group Supervisors signed PM task work orders as satisfactory when the acceptance criteria had not been met, failed to note the administrative and calculation errors noted above, failed to initiate appropriate corrective action documentation, and signed a PM work order as complete and satisfactory two days prior to the dates of the actual work. In addition, this supplement identified problems in which the Central Maintenance Electrical Work Control Planner/Coordinator misunderstood information on the Station Information Management System (SIMS) terminal display and made errors due to inattention to detail. The inspector reviewed QDR 90-0440 and the associated corrective actions. The Central Maintenance Electrical Supervisor is conducting mandatory briefings for all Central Maintenance electric shop personnel including Electricians, Foremen and Work Group Supervisors, and Central Maintenance Electrical Work Control Planner/Coordinators addressing the concerns noted above. The inspector concluded that this corrective action appears appropriate. This item is closed.

b. Unit 2

1. (Closed) Followup Item (529/90-23-01): "Inadvertent Trip of the 1B Reactor Coolant Pump Breaker" - Unit 2 (92701)

This item involved the tripping of a second Reactor Coolant Pump (RCP) breaker in a three month period due to jarring of an adjacent breaker cubicle while manually rolling the adjacent breaker into its cubicle. Engineering Evaluation Request (EER) 90-NA-009, which was issued as a result of the first event, was closed without additional corrective action recommendations. The Site Maintenance Manager and Maintenance Standards Manager discussed their intent to devise a tool to use to move these breakers into their cubicles with the inspector. During the Unit 1 Surveillance Testing Outage due to begin on January 12, 1990, Central Maintenance plans to remove a breaker to take measurements, then devise and fit up and finalize the design of the tool. No permanent changes will be made to plant equipment. The inspector concluded that this represents a positive step toward providing improved control of these breakers. This item is closed.

2. (Closed) Followup Item (529/90-28-01): "Inadequate Detail in Surveillance Procedure" - Unit 2 (92701)

This item addresses the "Main Steam PSV Set Pressure Verification" procedure, 73ST-9ZZ18, which contained no steps detailing the proper connection of test equipment or performance of the test, using the Trevitest method. The

inspector reviewed Revision 4, Procedure Change Notice 2 of procedure 73ST-9ZZ18, which was effective on November 6, 1990. Sufficient detail was added to the procedure to ensure the test device was properly installed and the test properly performed. Based on this review, this item is closed.

c. Unit 3

1. (Closed) Enforcement Item (530/89-56-01): "Failure to Follow Surveillance Procedure" - Unit 3 (92702)

This item involved the failure to close valve SIA-UV-603 at step 8.2.12 while performing surveillance test procedure 43ST-3SI06, "Iodine Removal System - S.C.A.P. Discharge Flow and Pressure Test." The licensee restored the valve lineup, counselled the operator involved and issued a night order addressing the issue to all operators. The procedure was revised to include an independent verification signoff. The licensee further committed to reviewing all Operations procedures to include signoff steps to document independent verification by September 2, 1991. The licensee has also conducted training for all operators on the new independent verification requirements. This item is closed.

2. (Closed) Enforcement Item (530/89-56-05): "Improper Atmospheric Dump Valve (ADV) Packing" - Unit 3 (92702)

This item involved the improper packing of valve 3J-SGB-HF-0178. The licensee reviewed this event in Human Performance Evaluation System Report 89-038 which concluded that there was inadequate self-checking on the part of the mechanics and an inadequate program to control valve packing. The HPES report noted the development of a new valve packing program and concluded that it should prevent recurrence of the use of valve packing which did not meet the valve manufacturer's specifications.

The inspector reviewed this program and noted that it is described in program procedure 73PR-9ZZ05, "PVNGS Valve Packing Program," and implemented in procedure 31DP-9MP02, "Valve Stem Packing and Gland Adjustment," in the new valve packing specification 13-PN-220, and the valve packing drawings 0X-P-ZZG-019 and 0X-J-ZZI-005 where X is the unit number. According to the licensee, specification 13-PN-220 was based heavily on EPRI Report NP-5697, "Valve Stem Packing Improvements," which recommended flexible graphite packing, and Equipment Change Evaluation ECE-ZZ-A158, which justified the use of graphite valve packing material at Palo Verde Nuclear Generating Station.

The inspector noted two weaknesses in the program. The first weakness, in procedure 73PR-9ZZ05, "PVNGS Valve Packing Program," is that in the list of responsibilities of Component and Specialty Engineering (C&SE), the program does not require

C&SE to review the Valve Survey and Data Sheets (VSDS) for technical appropriateness prior to forwarding them to Nuclear Engineering for incorporation into the valve packing drawings. The Manager, C&SE, committed to having procedure 73PR-9ZZ05 revised to state this technical review as a responsibility of C&SE. The second weakness was that the Unit 1 valve packing drawings were not issued and no schedule existed for the issuance of these drawings. The Manager, C&SE, committed to having these drawings issued during the three month period following the end of the present Unit 1 surveillance test outage. The inspector noted that the valve packing procedures have only been issued for Unit 3 and are scheduled to be issued for Unit 2 February 28, 1991. The inspector concluded that the corrective actions taken as a result of this violation appear adequate and that the new valve packing program represents an improvement. This item is closed.

3. (Closed) Enforcement Item (530/89-56-06): "Failure to Identify the Correct Maintenance Component" - Unit 3 (92702)

This item involved the installation of parts from containment purge exhaust valve 3J-CPA-UV-02B on containment purge supply valve 3J-CPB-UV-03A with a Quality Control (QC) holdpoint verification signoff. The licensee responded by counselling the individuals involved, performing a Human Performance Evaluation System (HPES) evaluation, and conducting training on "Effective Work Practices" for all site maintenance personnel. According to the Manager of Quality Control, QC Inspectors were not required to attend "Effective Work Practices" training, however a number of them did attend. QC revised their Plant Inspection Report document to require QC verification of component identification and QC personnel were briefed on the new form and on this event. The HPES report concluded that inadequate verbal communication and inadequate written communication contributed to the event. Corrective action included reviewing the HPES report with all affected work groups, conducting the "Effective Work Practices" training, and issuing Instruction Change Request (ICR) 18899 to evaluate the use of accurate descriptions in work orders. This item is closed.

3. Review of Plant Activities (71707 and 93702)

a. Unit 1

Unit 1 remained at essentially 100 percent power throughout this reporting period, except for a downpower to 75 percent on December 17, 1990, due to a Core Operating Limits Supervisory System (COLSS) failure. The unit was restored to full power the same day.

b. Unit 2

Unit 2 remained at essentially 100 percent power throughout this reporting period except for an MSIV closure event on December 21, 1990, which resulted in a forced power reduction to approximately 65 percent for several hours (see paragraph 9).

c. Unit 3

Unit 3 operated at approximately 100 percent power throughout this report period with the exception of a downpower to 40 percent from December 25, to December 27, 1990, to locate and repair a condenser tube leak.

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 Specifications requirements.

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

4. Equipment Lineups - Various valves and electrical breakers were verified to be in the position or condition required by Technical Specifications and administrative procedures for the applicable plant mode.

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

6. General Plant Equipment Conditions - Plant equipment was observed for indications of system leakage, improper

lubrication, or other conditions that would prevent the systems from fulfilling their functional requirements.

The inspector noted that a bolt was missing from the casing on the Unit 1 Essential Cooling Water "B" pump coupling. The licensee initiated Material Non-Conformance Report (MNCR) 90-EW-011 to address the deficiency and the bolt was replaced.

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

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

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

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

11. Radiation Protection Controls - Areas observed included control point operation, records of licensee's surveys within the Radiological Controlled Areas (RCA), posting of radiation and high radiation areas, compliance with Radiation Exposure Permits (REP), personnel monitoring devices being properly worn, and personnel frisking practices.

12. Material Control - Warehouse and material receipt, handling, storage and issue activities were reviewed.

    The inspector discussed the recent implementation of Level I certified QC inspectors for material receiving inspections with several warehouse personnel, including supervision and Level I and II certified inspectors. The inspector noted that although four warehousemen were given Level II training in October 1990, the licensee implemented a change to their receipt process which only required these personnel to be qualified to the lesser Level I standard (ANSI N45.2.6). Based on discussions with two of the four recently certified Level I inspectors, and a review of training and certification records, the inspector determined that the change to the licensee's receipt inspection process was being controlled by procedure, that the procedure provided for specific attributes for Level I receipt inspection, that this level of inspection was consistent with the level of

certification given to the Level I inspectors, and that previously all receipt inspections for quality related material were performed completely by Level II certified inspectors even though non-certified warehousemen also routinely performed some of the checks which would be normally done by Level I inspectors. Licensee personnel stated that receipt inspections were now more efficient in taking credit for the Level I inspector's checks, freeing the Level II inspector to inspect higher level attributes. Based on these discussions, the inspector concluded that ANSI N45.2.6 requirements relative to receipt inspector qualification and activities were being governed by approved licensee procedures.

No violations of NRC requirements or deviations were identified.

4. 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 31ST-9DG01	Diesel Engine 18 Month Inspection
o 32ST-9PE01	18 Month Surveillance Test of Diesel Generator
o 32ST-9ZZ03	Surveillance Test Procedures for the Class 4160 Bus Under Voltage Protective Relays

Unit 2

None

Unit 3

Procedure	Description
o 43ST-3ZZ16	Routine Surveillance Daily Midnight Logs

No violations of NRC requirements or deviations were identified.

5. 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 Inspection of Emergency Diesel Generator Piping and Oil Sample

Unit 2

Description

o Repair of "B" Emergency Diesel Generator Silencer

Unit 3

Description

o "B" Emergency Diesel Generator High Vibration Trip Troubleshooting

No violations of NRC requirements or deviations were identified.

6. Inadvertent Dilution of Reactor Coolant System Boron Concentration - Unit 1 (71707 and 92700)

The details of this event are described in LER 50-528/90-11 and the licensee's Incident Investigation Report (IIR) 2-1-90-004. In summary, on December 6, 1990, with Unit 1 at 100% power, the reactor coolant system boron concentration was diluted by approximately 3 ppm when a new ion exchanger was placed into service without adequate boron saturation. There were several weaknesses which were evident during the event and missed opportunities which could have prevented or mitigated the dilution event:

a. There was inadequate technical basis for the 20 minutes specified in the procedure for the flush of the ion exchanger and an informal process was used to communicate the criteria in the development of the procedure.

b. Operations' initial concern with the adequacy of the time specified in the procedure for boron saturation of the ion exchanger prior to being placed in service was not pursued to conclusion. Operations discussion with chemistry personnel were not adequate to resolve the concern.

c. The decision to concurrently perform high rate blowdowns of the steam generators also raised reactor power in addition to the dilution and caused the Core Operating Limits Supervisory System master alarm to annunciate. The operators expected the alarm due to the high rate blowdowns and therefore the alarm did not alert the operators to the dilution event.

d. Computer technicians failed to communicate to the operators the inability of the control element assemblies to move in sequential control mode which further complicated operator response to the dilution event.

The dilution occurred from approximately 1:53 a.m. to 2:49 a.m. on December 6. During this time the steam generators were being given a series of two minute high rate blowdowns. In combination with the dilution effect, this caused actual reactor power to exceed 100 percent for between one to two hours and exceed 101 percent for between 14 to 26 minutes. Although licensee calculations show that "best estimate" thermal power did not exceed the safety analysis upper limit of 102 percent, the licensee acknowledges in the IIR and LER that engineering calculations which account for all worst case uncertainties can be shown to result in peak power of nearly 104 percent. The licensee submitted the 10 CFR 50.73 report based on having exceeded licensed thermal power. When the operators attempted to drive CEAs into the core to limit the increased reactor power and RCS temperature, the CEAs would not respond in the manual sequential mode due to the unrecognized impact of a plant computer system malfunction. Operators were able to control CEAs in the manual group mode and mitigate the transient.

The inspector reviewed the licensee's IIR, LER, supporting documents, and noted the following:

The licensee determined that a dilution event in Mode 1 is bounded by the faster CEA withdrawal event which results in a reactor trip on VOPT or low Departure From Nucleate Boiling Ratio (DNBR), and no fuel damage, even assuming no operator action. Maintenance of reactor power below 102 percent on a steady state basis assures consistency with safety analysis assumptions. Furthermore, licensee policy guidance to operators allows for variations above the 100 percent licensed power, but held within the 102 percent limit, based on 1980 NRC guidance which suggests 100-102 percent power is "briefly" permissible "for as long as 15 minutes," provided the shiftly average of reactor power remains at or below the licensed (100 percent) limit. This guidance for shiftly average power appears to have been met in this case. The licensee review acknowledges the need to maintain tighter control over RCS parameters during such evolutions and management counseled the shift supervisor in this regard. The inspector considered this action appropriate.

The licensee's review determined that computer technicians were aware of a computer malfunction which caused de-energization of circuit cards in the plant computer two days prior to this event. The IIR did not acknowledge that these technicians should have been able to provide operators with enough information to alert them to

the impact on CEA Control. This was demonstrated by the technician's ability to provide information to operators in the context of the plant indication and control which would be lost while restoring power to the cards. In subsequent discussions with the inspector, licensee management agreed to emphasize to operators and computer technicians the need for thorough analysis of current plant impact due to malfunctioning equipment.

Finally, the licensee issued Quality Deficiency Report (QDR) 90-485 to correct the procedure guidance for placing a new resin bed in service and for preventing recurrence of similar procedural inadequacies. The inspector noted that the IIR did not delve into the reasons why the procedure was deficient, relying instead on the QDR program to sufficiently resolve this issue. The inspector determined that the underlying cause was that technical information regarding the length of time needed to borate a new resin bed to RCS concentration was communicated verbally from Chemistry Standards to the Operations Standards group writing a procedure revision in May 1990. Apparent misunderstanding and lack of critical review of the basis for this information contributed to its being approved in the revision. The response to the QDR was to incorporate the licensee's existing Engineering Evaluation Request (EER) program as a means of documenting the transmittal of technical information between Standards groups. Although this appears to provide more formality, the inspector emphasized to licensee management that such documentation must still be critically reviewed and challenged when necessary prior to its use in approved procedures. A previous example of a procedure deficiency due to misunderstood engineering input was recently discussed in NRC Inspection Report 528/90-46 (paragraph 9), but resulted in more conservative requirements than were necessary. The inspector concluded that the failure to provide a required procedure with appropriate criteria for determining the satisfactory accomplishment of this important activity is a violation of 10 CFR Part 50, Appendix B, Criterion V (50-528/90-54-03).

7. <u>Diesel Generator Operability - Unit 1 (61726 and 92700)</u>

While observing performance of Surveillance Test 31ST-9DG01, "18 Month Diesel Generator Inspection," on the "B" Emergency Diesel Generator (EDG) on December 18, 1990, the inspector noticed that the opposite Train EDG (Train "A") had a "Diesel Inoperable/Malfunction" local annunciator lighted. The local annunciator for low lube oil pressure was also lighted. If these alarms were valid, the EDG would be inoperable.

The inspector determined that the EDG "A" inoperable indication had been first identified on December 15, 1990, and that the Shift Supervisor (SS) had evaluated the problem and determined that it was an annunciator problem only and that the EDG was operable. This was based on the licensee's verifications that none of the parameters identified in the alarm response procedure were in a condition to provide a valid alarm, that no control room EDG trouble alarm or Safety Equipment Status System (SESS) alarm was present, and that a

valid local annunciator would result in the appropriate control room alarms. Additionally, the Assistant Shift Supervisor telephoned the duty Instrumentation and Controls (I&C) Technician and explained the observations. The I&C Technician concurred with the conclusion that EDG "A" was operable. However, no log entries document the checks which were made to verify EDG operability.

On Monday, December 17, 1990, High Pressure Safety Injection (HPSI) Train "B" was taken out of service for planned maintenance. Later that day, the Operations Manager became aware of the EDG "A" "Inoperable/Malfunction" annunciator and directed that I&C confirm that the condition was simply an annunciator circuit problem. This effort consisted of checking continuity across the contacts which cause the annunciator to be on. The contacts were determined to be closed, which should not cause the alarm. I&C concluded that the annunciator circuit card was faulty. However, the condition was not corrected at that time. Additionally, the I&C Technician used an uncontrolled diagram instead of controlled drawings while performing this troubleshooting confirmation. Licensee management stated that their expectation was that controlled drawings should have been used.

The Operations Manager authorized the SS to take the opposite Train "B" EDG out of service and declare it inoperable for 18 month surveillance testing, providing the SS had no operability questions about the "A" EDG after the I&C troubleshooting. The "B" EDG was thus removed from service on December 18, 1990. The annunciator circuit card on the "A" EDG was subsequently replaced.

After detailed discussions with the licensee's engineering staff and examination of the related logic prints, the inspector agreed that the EDG "A" annunciator problem did not impact operability. However, up to this point, engineering had not been involved in the resolution of the problem, and no other attempt to confirm the scope of the problem via the logic diagrams had been made.

Procedure 40AC-90P02, "Conduct of Shift Operations," states that "when key decisions are made, the thought process for that decision should be logged, for reconstruction at a later time." The determination that EDG "A" was operable in spite of the "inoperable/malfunction" annunciator, particularly prior to making opposite train equipment inoperable for planned maintenance, appears to be a "key" decision.

The inspector concluded that adequate information was used by the SS to verify EDG "A" operability, but that documentation of this verification was poor. The licensee concurred that this should have been documented.

No violations of NRC requirements or deviations were identified.

8. Turbine Driven Auxiliary Feedwater (AFW) Pump Oil Levels - Units 1 and 3 (92700)

On December 28, 1990, a Unit 1 Auxiliary Operator (AO) reported that the oil level in the turbine driven AFW pump, 1AFA-P01, was 1/8 inch higher than the upper limit mark on the sightglass. A locally mounted placard declares that oil level must be maintained between the marks on the sightglass. As a result of this finding, the pump was successfully operated to ensure that the high oil level would not prevent operation. Subsequently, the oil was changed and level restored to the normal band. A sample of the old oil was obtained, analyzed, and found to be normal.

On January 1, 1991, the oil level in 1AFA-P01 was again observed to be about 1/8 inch above the upper mark. This oil was sampled for lab analysis and about 12 ounces of oil were drained out to restore the level. The licensee initiated Engineering Evaluation Request (EER) 91-AF-01 to determine why the level was too high.

On January 4, 1991, the inspector checked the Units 2 and 3 turbine driven AFW pumps, and found that the Unit 3 pump, 3AFA-P01, had an oil level about 1/8 inch above the mark at the inboard bearing. Level was about 1/4 inch above the mark at the outboard bearing sightglass. The Unit 3 shift supervisor noted that the oil had been changed and a routine oil sample had been taken a few days previously. He requested maintenance to drain the oil as necessary to restore the level.

The inspector noted that the AO logs have a different acceptance criteria for oil level than what is provided by the placard. The logs have no limit on the maximum allowed level, and the minimum level allowed is "no visible level." The normal level given is 50 percent, though the sightglass has no numerical scale or mid-point mark. The licensee submitted Instruction Change Request (ICR) 15434 to correct this discrepancy.

The significance of marginally high oil levels has not been determined. This item will remain open until the inspector reviews the results of the licensee's evaluation of the cause and significance of high oil levels (Followup Item 528/90-54-01).

No violations of NRC requirements or deviations were identified.

9. Closure of One of Four Main Steam Isolation Valves (MSIV) While at 100 Percent Power - Unit 2 (93702).

At approximately 5:45 AM, (MST) on December 21, 1990, MSIV 170 unexpectedly closed while the plant was operating at 100 percent power. This malfunction affected only one of two MSIVs associated with the No. 1 steam generator. Operators reduced plant power to approximately 65 percent and stabilized plant parameters. Plant response to this event was subsequently determined by the licensee to be as expected, with no significant abnormalities noted. Operator action was briefly required to operate the No. 1 steam

generator feedwater control system in manual, and an approximately seven degree difference in cold leg temperatures between steam generators created a sufficient core azimuthal flux tilt (1.03) to require changing the Core Protection Calculator (CPC) AZTILT parameter in accordance with the provisions of Technical Specifications. Additionally, the unaffected steam line on the No. 1 steam generator initially passed excessive steam flow and over-ranged the steam flow instrument used to correct the steam header pressure instrument which inputs to the Core Operating Limits Supervisory System (COLSS) secondary calorimetric power calculation. The steam flow instrument came into range at power levels less than 70 percent as expected.

The licensee determined that the cause of MSIV closure was a failed solenoid operated air valve (Skinner/Honeywell Model V5-61090) associated with the Anchor/Darling MSIV. Once plant conditions were stabilized, the air valve was replaced, and the MSIV was opened and surveillance tested satisfactorily. The licensee initiated a root-cause-of-failure analysis on the failed valve (Engineering Evaluation Request 90-SG-221).

The overall licensee response to this event appeared well coordinated. The NSSS vendor was promptly consulted, Nuclear Fuels Management department quickly provided a simulation of plant response which helped confirm that the actual response was as expected, Reactor Engineering coordinated on-site engineering evaluation and assessment, and maintenance and material support were efficient and effective in restoring the MSIV to service. The licensee restored the plant to normal operations late that afternoon and restored full power operation later that evening. The licensee also initiated an Incident Investigation to assess the transient in more detail.

The inspector noted two areas of apparent weakness in the licensee's performance in response to this event. First, the licensee based the determination of satisfactory plant response on the simulation which showed a maximum seven degree delta T-cold, operator statements that delta T-cold was not seen to be larger than seven degrees, engineering judgement which extrapolated a four degree delta T-cold at 83 percent power to a seven degree delta T-cold at 100 percent power, a review of CPC functional requirements of which protection from this specific transient was included, a physical check of CPC auxiliary trip setpoints of fifteen degrees delta T-cold, and NSSS vendor concurrence with the above. The inspector noted that after the plant had been restored to normal operation but prior to restoring full power operation, available precise plant parameter transient response (TDAS) data was not accessed and reviewed. Although the inspector considered the licensee had sufficient basis to assure the plant remained within its design envelope throughout the transient, the TDAS plots represented the most precise data available to confirm actual plant response. Licensee management agreed that this data could have further contributed to confirmation of plant response.

Second, the inspector questioned unit operations management during the transient on how the over-ranged steam flow instrument affected the calculations performed by COLSS. Operations management at that time could not confirm that COLSS was impacted by this over-ranged instrument. The operations staff or shift had not been informed of any impact and were not considering the possibility of any adverse effect. On further questioning, the operators and a computer technician confirmed the use of this instrument as an input to COLSS. Subsequently the licensee informed the inspector that the impact on COLSS did not affect the validity of COLSS calculations. The inspector stressed the need for operators to task supporting groups such as engineering to provide such assessments. Licensee management acknowledged these comments and noted that consideration was being given to creating additional reference documents to assist operators in assessing the impact of various sensor or instrument failures. Additionally, development of an operations procedure was initiated to provide specific guidance to operators for this event.

No violations of NRC requirements or deviations were identified.

10. Use Of Improper Fuses In Safety-Related Applications - Units 1, 2 and 3 (62703)

The inspector reviewed an issue previously identified by the licensee related to the possible use of incorrect fuses in Beta Products equipment.

The inspector reviewed Reportability Evaluation Report (RER) 89-03, which determined that these problems did not warrant a 10 CFR Part 21 report. The corrective action section did, however, indicate the need for an evaluation of other Beta supplied fused equipment to determine if this problem existed in other equipment. This evaluation was to be documented in Engineering Action Request (EAR) 89-0831. The inspector concluded that the RER appeared appropriate.

The inspector reviewed EAR 89-0831 and found that it was still open. The EAR was initiated on May 10, 1989 with the Nuclear Engineering Department responsible for this EAR. Unit 3 inspections were completed by August 1989, however, due to personnel changes, the Nuclear Engineering Department was unaware of this status until January 1991. The status of the inspections and individual responsibility for the EAR had not been communicated until questioned by the NRC inspectors in December 1990. The NED supervisor responsible for the completion of this EAR indicated that it had routine priority and that it would be completed after completing higher priority work. The inspector concluded that in this case, the EAR prioritization process was weak, in that after one year there was no planned completion date. The inspector further concluded that in this case communications were ineffective in transmitting requested data from the field to NED.

The inspector reviewed Work Orders 393611, 393528, 400054, and 429555, which covered all the units. These work orders were issued to perform these fuse inspections in various safety and non-safety

cabinets. The inspector noted that the form used to collect the data in Unit 2 had a pen and ink column added to document independent verification of the reinstallation of the fuses. In the work orders for Unit 3, the data form had pre-printed columns which duplicated the independent verification pen-and-ink columns used at Unit 2. Unit 1 used a determ/reterm sheet. The inspector noted that Procedure 30DP-0AP01, "Maintenance Instruction Writer's Guide", states in Section 3.2.4 on page 11 of 44 that "The removal and reinstallation of the same component shall be documented on a component removal/reinstallation form ... or controlled by the work instruction." While the use of a column on a form or a determ/reterm sheet is not explicitly in accordance with the requirements of 30DP-0AP01, its use provided the same independent verification of that required by the component removal form. The inspector concluded that this was a minor difference.

In addition, the inspector noted that the work order entry for Work Quality Related ("WK QR") was listed as no ("N") on the cover page of the work orders for each unit, yet the work orders received the technical and quality reviews normally associated with Quality Class work orders. The reason for this is that some of the fuses being inspected were Q-Class and some were not, and this had been marked "N" in error. The work order received a technical and quality review despite the incorrect flag in the "WK QR" field. The inspector concluded that except as noted above, the work orders appeared appropriate for the planned task with adequate detail and references.

Work order 393611 for Unit 1 had not been completed. According to notes in the work order and discussion with personnel from Work Control, including the Planner Coordinator, this work stopped when a Q-Class fuse for the annunciator circuit for a Class 1E circuit was broken in May 1990. These discussions also indicated that this fuse only had a Beta Products part number which they could not cross reference to any other fuse. In addition, other higher priority work delayed the procurement of the replacement fuse. By June 14, 1990 the Planner Coordinator initiated a request to Materials for a replacement fuse. Purchase Request 9535389 was written on August 2, 1990. The Station Information Management System indicates that the lead time for procuring this fuse after a purchase order is issued is 37 weeks. According to the Planner Coordinator, as of January 7, 1991 a Purchase Order had not been issued. This broken fuse had no impact on the affected equipment because it was in a redundant power supply. The inspector discussed availability of Q-Class fuses with an I&C Foreman, the I&C System Engineer for these systems, the NED I&C Engineer for these systems, and with a Procurement Engineering representative. None of these discussions identified any unusual difficulties in obtaining Q-Class fuses. The inspector also discussed this with the Planner Coordinator who said that there had been difficulty obtaining fuses in some situations and that in this case there was a class and item number but no stock for the fuse in the warehouse. The inspector concluded that low priority resulted in the lengthy delay in obtaining the replacement fuse.

The inspector concluded that inadequate ownership of this issue appears to have delayed the completion of corrective action. The licensee initiated Problem Resolution Sheet 1613 to evaluate the significance of the concerns raised regarding this EAR and any possible broader implications. The inspector will review the results of this investigation when the PRS is closed (Followup Item 528/90-54-02).

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

The following LER was reviewed by the Resident Inspectors.

Unit 1

528/90-11-LO (Closed) "Reactor Thermal Power License Limit Exceeded." - Unit 1

This event is described and reviewed in paragraph 7 of this inspection report. Based on this review, this LER is closed.

12. Exit Meeting

The inspector met with licensee management representatives periodically during the inspection and held an exit meeting on January 8, 1991.