U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.: 50-528/90-20, 50-529/90-20 and 50-530/90-20

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

License Nos.: NPF-41, NPF-51, NPF-74

Licensee: Arizona Public Service Company
P. O. Box 52034
Phoenix, AZ. 85072-2034

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

Inspection Conducted: April 15 through May 26, 1990

Inspectors:
D. Coe, Senior Resident Inspector
F. Ringwald, Resident Inspector
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Approved By: Howard J. Wong 6/25/90
H. Wong, Chief Date Signed
Reactor Projects Branch, Section II

Inspection Summary:

Inspection on April 15 through May 26, 1990 (Report Numbers 50-528/90-20, 50-529/90-20, and 50-530/90-20)

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors, plus two inspectors from the Region V staff. Areas inspected included: previously identified items; review of plant activities; engineered safety feature system walkdowns; monthly surveillance testing; monthly plant maintenance; reactor coolant pump oil collection system non-conformance - Unit 1; post-accident sampling system (PASS) over-pressurization - Unit 1; dirty atmospheric dump valve (ADV) nitrogen regulators - Unit 1; steam generator hydrolase - reactor coolant system (RCS) dilution - Unit 1; steam generator (SG) tube leak - Unit 1; inadvertent reactor coolant system (RCS) fill flowpath - Unit 1; shutdown cooling throttle valve design deficiency - Unit 1; reactor coolant pump (RCP) "1B" breaker trip - Unit 1; refueling water tank (RWT) stratification - Unit 1; inadvertent shutdown cooling (SDC) bypass flow - Unit 1; MOVATS testing - Unit 1; turbine driven auxiliary feed pump steam admission valve mis-wiring Unit 1; loss of shutdown cooling while preparing for mid-loop operations - Unit 1; confirmatory action letter followup - Unit 1; refueling activities a. fuel reload, b. cavity seal, c. broken incore instrument - Unit 2; broken westinghouse steam generator tube plug - Unit 2; charging pump valve misalignment - Unit 2; inadvertent discharge of carbon dioxide - Unit 2; inadequate retest of

motor operated butterfly valve - Unit 2; steam generator (SG) U-tube mis-plugging, a. 1988 refueling, b. 1990 refueling - Unit 2; reactor coolant system spill - Unit 2; atmospheric dump valve (ADV) nitrogen accumulator found isolated - Unit 3; ECCS pump room material control - Unit 3; temporary instruction 2515/104: fitness for duty (FFD) initial training programs - 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:

TI 251510, 30703, 60710, 61726, 62703, 71707, 71710, 82301, 92700, 92701, 92702, 92703 and 93702.

Results: Of the 32 areas inspected, 2 violations were identified and are being cited. These violations involve the failure to follow procedures: (1) to open a valve which led to overpressurizing the PASS and (2) to maintain the status of a locked open valve associated with an Atmospheric Dump Valve.

Three non-cited violations involved: (1) the mis-wiring of a steam admission valve to the turbine driven Auxiliary Feedwater Pump; (2) the failure to open the suction and discharge valves for a charging pump when being tested; and (3) the failure to install a steam generator hot leg plug for a tube which had a greater than 40% defect.

General Conclusions and Specific Findings

Significant Safety Matters:	None
Summary of Violations:	2 Cited and 3 Non-Cited Violations
Summary of Deviations:	None
Open Items Summary:	14 items closed, 1 item left open, and 7 new items opened.

DETAILS

1. Persons Contacted:

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

Arizona Public Service Company

R. Adney,	Plant Manager, Unit 3
*R. Badsgard,	Engineering and Construction Supervisor
*J. Bailey,	Vice President, Nuclear Safety & Licensing
B. Ballard,	Quality Assurance Director
F. Buckingham,	Operations Manager, Unit 2
H. Bieling,	Emergency Plan/Fire Prevention Manager
*T. Bradish,	Compliance Manager
P. Brandjes,	Central Maintenance Manager
P. Caudill,	Site Services Director
*W. Conway,	Executive Vice President - Nuclear
*J. Draper,	S.C.E., Site Representative
*S. Gross,	El Paso Electric Engineer
D. Heinicke,	Plant Manager, Unit 2
*P. Hughes,	Radiation Protection/Chemistry Manager
*W. Ide,	Plant Manager, Unit 1
*R. Joyce,	Maintenance Manager
*S. Kanter,	Participant Services, Senior Coordinator
*J. Levine,	Vice President, Nuclear Power Production
J. LoCicero,	Independent Safety Engineering Manager
W. Marsh,	Plant Operations & Maintenance Director
*G. Overbeck,	Technical Support Director
*C. Russo,	Quality Control Manager
*E. Sandhoff,	QA&M, Engineer
*J. Scott,	Chemistry Manager
W. Simko,	Maintenance Manager, Unit 2
E. Simpson,	Vice-President of Engineering & Construction
R. Snell,	Chairman Arizona Public Service
*G. Sowers,	Engineering Evaluations Manager
*D. Stover,	Nuclear Safety Manager
C. Stewart,	Employee Concerns Program Manager
*L. Templeton,	I.S.E., Senior Engineer
P. Wiley,	Work Control Manager, Unit 2
R. Younger,	Plant Standards and Control Manager

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 May 31, 1990.

2. Previously Identified Items - Units 1, 2, and 3 (61726, 92701, 92702 and 93702)

a. (Closed) Followup Item (528/89-54-01): "Material Non-Conformance Program" - Unit 1

This item involved the improper invalidation of a Material Non-Conformance Report (MNCR). The licensee committed to and did revise the MNCR program implementing procedure 60AC-OQQ01, "Control of Non-Conforming Items," to eliminate the potential for the improper invalidation of an MNCR. Quality Assurance also committed to issuing a "Quality Talks" memo to clarify the development of the MNCR program. The inspector reviewed the revision to 60AC-OQQ01 and the "Quality Talks" memo and was satisfied that the problem appears to have been addressed. The inspector will continue to evaluate MNCR program implementation. This item is closed.

b. (Closed) Unresolved Item (528/90-03-01): "Containment Hydrogen Monitor Surveillance" - Unit 1

This item involved a surveillance test which was signed off as complete with an apparently shorted zero potentiometer. The I&C Supervisor unsuccessfully attempted to duplicate the indication of the short with the zero potentiometer locking mechanism engaged. The system engineer stated that the Hydrogen Monitor front panel was seismically qualified so the locking device would remain locked during a seismic event. A work order has been written to replace the zero potentiometer prior to the restart of Unit 1 from the current outage. This item is closed.

c. (Closed) Enforcement Item (529/89-54-01): "Blown Fuse on Power Supply to Valve AFA-HV-54" - Unit 2

This violation was related to ineffective corrective actions to prevent the use of improper indicating light bulbs, which twice caused fuses to blow, disabling control form the Control Room of the turbine-driven auxiliary feedwater pumps trip throttle valve.

The licensee has attributed both of these events to cognitive personnel errors, but the specific circumstances of the December 21, 1989, event were not determined. Consequently, several actions were implemented to prevent recurrence. These actions included installing the correct light bulbs in the control circuit, reviewing other plant equipment to ensure proper bulbs were installed, changing the bulb storage cabinet to better consider human factors, removing the type of bulb incorrectly used in both events from the cabinet because this type of bulb was determined not to be needed by operations personnel, and writing a Night Order to restate the proper procedure for replacing indicating bulbs which had blown out for all plant equipment. These actions are considered adequate. This item is closed.

3. Review of Plant Activities (71707 and 93702)

a. Unit 1

The unit began the report period in Mode 5. The unit entered Mode 4 on April 17, 1990, heated up and entered Mode 3 on April 18, 1990. Several valve leak repairs were performed as the unit heated to normal operating temperature and pressure. Main steam safety valve setpoint (Furmanite Trevitest Method) testing was performed. A primary to secondary leak (tube leak) was identified in steam generator No. 2. Atmospheric Dump Valve (ADV), Steam Bypass Control Valve and Auxiliary Feed Pump testing was performed with conservatively evaluated release permits, radiation monitor readings, and steam generator samples taken between each release. All releases were within acceptable limits. The unit cooled down to Mode 4 on May 4, 1990, and entered Mode 5 later the same day. The unit was depressurized, vented, and entered a reduced inventory condition on May 8, 1990. On May 9, 1990, a complete loss of Shutdown Cooling (SDC) occurred (See Paragraph 19). Mid-loop operation was achieved on May 11, 1990. The Reactor Coolant Pump "1B" second stage seal had been leaking and was replaced.

Steam generator nozzle dam installation on steam generator No. 2 was completed on May 14, 1990, and RCS level was restored from the reduced inventory condition on May 15, 1990. The primary-to-secondary leak was identified as a leaking steam generator tube plug (See Paragraph 11). The unit ended the inspection period in Mode 5 with the nozzle dams in place with the RCS vented at approximately three feet below flange level.

b. Unit 2

Unit 2 was in Mode 6 and defueled at the beginning of the report period. Loading fuel into the reactor vessel commenced May 13, 1990, and was complete on May 20. Major outage activities performed during this period included: steam generator tube inspections and plugging; reactor coolant pump overhaul and reinstallation; overhaul of many breakers; control element drive mechanism coil repairs; implementation of many design modifications; replacement of a pressurizer heater; and overhaul of the "B" emergency diesel generator. The plant remained in Mode 6 for the rest of the reporting period.

c. Unit 3

Unit 3 began this report period in Mode 3 having tripped on April 14, 1990, due to a dropped Control Element Assembly during testing (see NRC Inspection Report 530/90-12). Unit 3 was returned to service on April 19, 1990, but due to repairs needed on two high pressure feedwater heaters with cracked divider plates, remained at 90 percent power until April 28, 1990, when it returned to 100 percent and operated at essentially that power level through the remainder of the reporting period.

d. Plant Tours

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

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

The following areas were observed during the tours:

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

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

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

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

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

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

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

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

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

The Secondary Alarm Station was included in plant tours.

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

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

12. Shift Turnover - The inspector observed a shift crew turnover in Unit 2. The turnover was conducted in a professional manner. The Shift Operators each walked down the control boards with the relieving Operators. Proper emphasis was given to the status of current activities. A shift briefing was conducted, and formal Control Room decorum was maintained.

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 inspector to confirm that the systems were aligned in accordance with plant procedures.

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

Unit 1

- o Shutdown Cooling
- o Reactor Water Level Indicating System

Unit 2

- o Shutdown Cooling

Unit 3

- o "A" Train Safety Injection
- o Shutdown Cooling - During the walkdown of the Unit 3 "A" Shutdown Heat Exchanger Room the inspector observed a cigarette butt and a candy wrapper which were removed by the Radiation Protection (RP) Technician. The "A" shutdown Heat Exchanger Room at the time was posted as a Locked High Radiation Area.

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 (T/S) 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 T/S; 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 36ST-9SE04	Excore Startup Channel Functional Test
o 41ST-1CH04	Boron Injection Flow Test
o 41ST-1RC01	RCS and Pressurizer Heatup and Cooldown Rates
o 41ST-1SG05	ADV Nitrogen Accumulator Drop Test
o 41ST-1ZZ09	Containment Cleanliness Inspection: During the performance of 41ST-1ZZ09 the inspector observed several bags of debris, tape, herculite, one socket wrench and socket plus one cigarette butt which were all removed from containment by the Auxiliary Operator.
o 73ST-9SI01	ECCS Flow Balance Test

Unit 2

Procedure	Description
o 36ST-2SE01	Excore Safety Channel Log Calibration
o 36ST-9SB03	Plant Protection System Calibration

Unit 3

Procedure	Description
o 36ST-9SE12	Excore Safety Channel Calorimetric Compensation

No violations of NRC requirements or deviations were identified.

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

a. During the inspection period, the inspector observed and reviewed selected documentation associated with maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required Quality Assurance/Quality Control involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel

qualifications, and proper retesting. The inspector verified that reportability for these activities was correct.

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

Unit 1

Description

- o Disassemble ADV N2 Regulator SG-PCV-323.
- o Repack RC-432 with backseat as isolation.
- o 73TI-9SG06 ADV Function Test SG-178, 179 and 181.
- o 31MT-9CH01 Repack CHA-P01.
- o RCP 2B Breaker Rack In/Alignment Check.
- o PM Task-Replace ADV Air Supply Filter Element.
- o 32MT-9ZZ32 Maintenance of Medium Voltage Circuit Breakers AM-13.8-1000.
- o Steam Bypass Control Valve Time Response Test SG-1002, 1007, and 1008.

Unit 2

Description

- o Calibration of differential pressure loop for 2B Reactor Coolant Pump (RCP)
- o Repair misaligned mounting holes on Control Element Assembly Calculator #2
- o MOVATS test of 2-SIB-656
- o Installation of RCP Vibration Monitoring Cabinet
- o Retest of Engineered Safeguards Features Actuation System (ESFAS) relays - Train "A"
- o Retrieval of broken incore instrumentation

Unit 3

Description

- o Vibration Testing on Coolant Charging Pumps
- o CEDMCS Undervoltage Relay Replacement

i. The inspector observed troubleshooting and repair activity conducted on the Control Element Drive Mechanisms Control System (CEDMCS) Undervoltage (UV) relay, UV-1. The repair was conducted on Unit 3 with the plant at 100 percent power using Work Order (WO) No. 424333. The WO documentation was completed in accordance with work control procedures.

The troubleshooting activity began when a UV indication lighted on the CEDMCS local indication panel. The significance of this indication was that the phase monitor (K1) relay had detected a potential UV on the power supply

to the CEDMCS and caused a one channel trip of the CEDMCS. Because of a potential turbine trip, the licensee decided to immediately troubleshoot the cause of the UV indicator.

The WO only specified that the output voltage of the CEDMCS Motor Generator (MG) set No. B was to be measured. Upon troubleshooting in the field by both Maintenance and System Engineering personnel, the licensee determined that the actual field ampere readings were 1.05 and 1.06 respectively, within the required current range. Voltage measurements taken indicated 138.5 volts between phases "A", "B", and "C" to neutral, which was within specification. Personnel in the field concluded that the UV indication was not attributable to an MG set problem. Since the WO contained steps which permitted troubleshooting, repair and replacement of parts, licensee personnel elected to continue troubleshooting.

Additional measurements were conducted by maintenance personnel under the direction of System Engineering personnel. Voltage measurements were made at the K1 relay which performs the phase monitor function. Licensee personnel concluded the cause of the UV indication was due to the K1 relay malfunctioning and verified that the WO would permit the replacement of the K1 relay under the current WO without revision. A jumper was installed across the K1 relay contacts to minimize any electrical transient during the relay replacement.

The inspector discussed with maintenance supervision whether the above scope of work was permitted by the WO, since the logic and voltage measurements across the K1 relay were neither authorized to be conducted by the WO nor documented by personnel after they were measured. Maintenance supervision stated that the current WO did permit the replacement to be performed, however, the measurements performed at the K1 relay would be documented in the WO.

The inspector concluded that both maintenance and system engineering personnel were very knowledgeable of systems under troubleshooting and found the location of the relays in question quickly. WO planning and documentation were minimal, in that the WO gave specific instructions on the measurement of the MG set output voltage only. This measurement was not needed since the local indication of MG set output voltage was within requirements and could have been verified with installed instrumentation in the earlier stages of WO planning. Once the licensee's personnel concluded that the problem was no longer the MG set output voltage, they proceeded with other troubleshooting which correctly led to the specific relay (K1) which was causing the UV indication, however the work and measurements were not documented until several hours

later after the inspector discussed the activity with maintenance supervisors. The maintenance work activity appeared to be conducted in compliance with the licensee's procedures although there appeared to be a lack of complete documentation during troubleshooting activities.

ii. The inspector noted that following maintenance on the "E" Charging Pump (CCP), herculite sheets were left covering various portions of the pump and motor even after the pump was given a pre-start check by operations personnel and then placed in service. The inspector noted that the herculite was partially obstructing the airflow through air cooled bearings on the gear box.

The inspector considers that this is a poor practice which could result in premature failure of a component required by Technical Specifications. Also, in conjunction with the lack of an adequate pre-start check on a Unit 2 CCP (See Paragraph 23), it points to the need for strengthening adherence to the licensee's existing pre-start check requirements and better sensitivity to the potential impact of abnormal conditions. Licensee management acknowledged these observations.

No violations of NRC requirements or deviations were identified.

7. Reactor Coolant Pump Oil Collection System Non-Conformance - Unit 1 (93702)

A walkdown of the Reactor Coolant Pump configuration by the System Engineer revealed that the Oil Collection System, required by 10 CFR Part 50, Appendix R, did not conform to the design in that thermal expansion "S" - bends in tubing did not have the proper shape, that some tubing supports were not installed, that unions were used in lieu of "T" - connections and that tubing support screws were damaged and not in accordance with the design. A Material Non-Conformance Report was issued and a conditional release was authorized to make interim modifications to install proper thermal expansion "S" - bends. Final disposition will be to replace the tubing during the next outage to conform to the original design. During the interim tubing replacement, the mechanics identified that the "S" - bend tubing which was removed was thick wall tubing rather than the designed thin walled tubing. The licensee did not have a clear history of when the tubing was installed, removed or reinstalled. A walkdown of the same system in Unit 2 revealed that it was installed as designed. During the 1989/1990 outage of Unit 1, Westinghouse contract workers removed at least some of this piping and requested replacement tubing for some of the removed piping which had been damaged. The inspector concluded that this represents poor system configuration control. Based on information received by the end of this inspection period the inspector concluded that no design verification checks were performed prior to the walkdown by the System Engineer. Since a determination of

whether design verification requirements exists for this system could not be made by the end of this inspection period, this will remain an Unresolved Issue (50-528/90-20-01).

8. Post-Accident Sampling System (PASS) Over-Pressurization - Unit 1 (93702)

On April 22, 1990, while performing surveillance testing of the PASS, a mispositioned valve resulted in the over-pressurization of portions of the PASS and Hydrogen Monitoring system. Chemistry and Operations personnel were working to sample the reactor coolant using Surveillance Procedure 74ST-9SS02, "Post Accident Sampling System Leakage Monitoring." Due to mis-communication between the Chemistry and Operations personnel, Reactor Drain Tank return valve, 1-CHUV-715, was not opened. This allowed RCS pressure at 1750 psia, to dead-head against spring-loaded check valve, SSHV-332, which leaked by. This then allowed RCS pressure to be applied to shut solenoid valve, SSHV-73, which also leaked by to the gaseous portion of PASS and then to the "A" Train Containment Hydrogen Recombiner.

This apparently over-pressurized the gaseous portion of PASS and the Hydrogen Recombiner and Monitor. The failure to follow applicable procedures is an apparent violation of NRC requirements (50-528/90-20-02).

The licensee disassembled, examined, cleaned, reassembled and hydrostatically tested check valve SSHV-332 prior to returning PASS to service. Valve SSHV-73 is designed to leak when pressure is applied in the reverse direction. The licensee's Incident Investigation Report concluded that mis-communication between the Chemistry and Operations department caused the event and both individuals were counseled on improving communication.

9. Malfunctioning Atmospheric Dump Valve (ADV) Nitrogen Regulators - Unit 1 (93702)

ADV Nitrogen Regulator PCV-303 did not properly control pressure during Surveillance Test, 41ST-1SG05, "ADV Nitrogen Accumulator Drop Test". During the ADV nitrogen drop test, a valve calibration could not remedy the problem. When nitrogen pressure regulator PCV-303 was disassembled in the presence of the inspector, foreign particles were found in the internals components, particularly in the soft seat portion of the pilot valve seating surface. These valves are manufactured by Target Rock. The Target Rock vendor representative stated these particles may contribute to a pressure control problem. The system engineer requested a flush of the nitrogen system which was performed on May 12, 1990. Subsequently, another pressure regulator, PCV-323, also failed to control properly during performance of Surveillance Test 41ST-1SG05 and could not be calibrated. When PCV-323 was disassembled in the presence of the inspector there was dust, corrosion products and metal particles in the internals and imbedded in the pilot valve soft seat. The licensee initiated a root cause of failure (RCF) analysis, cleaned and polished the valve internals and restored the systems to service

following appropriate testing. Although the RCF analysis was not complete and was intended to include a series of bench tests of an identical regulator, the licensee believed that regulator mechanical problems such as improper assembly was the more likely cause. In the absence of a confirmed RCF analysis, the licensee had not determined that any compensatory measures were needed. The inspector noted that the only calibration check planned for the regulator was initiated by known performance problems, no routine preventive maintenance calibration check was to be performed. Also, even though the instrument air supply to the ADV's was filtered, there were no installed filters for the nitrogen supply.

Although the licensee plans to install nitrogen filters by April 1992, no methods were planned to routinely check nitrogen system purity until that time. Following the inspector's questions, the licensee committed to evaluate routine regulator PM calibration checks (EER-90-SG-0112) and routine nitrogen purity checks (EER-90-GA-010) until filters were installed. The inspector concluded that the licensee had not aggressively dealt with all aspects of the known ADV regulator performance problems, but that the committed actions appeared appropriate.

No violations of NRC requirements or deviations were identified.

10. Steam Generator Hydrolase - Reactor Coolant System (RCS) Dilution - Unit 1 (93702)

On May 12, 1990, while a contractor was hydrolasing the No. 2 Steam Generator (SG), the suction tubing to the air operated pump lost suction. The SG bowl filled up and approximately 800 gallons of demineralized water entered the RCS when it spilled over into the RCS hot leg, diluting the RCS boron concentration from 3120 ppm to 3050 ppm. Adequate shutdown margin was maintained during the event. The work order for this activity did not have specific guidance for monitoring the SG bowl suction. The work order was subsequently amended for Chemistry personnel to monitor RCS boron concentration hourly. According to the contract workers, flow indicating devices were not used in the suction tubing, however, they asserted that they were able to detect when the suction pump was not removing water. They also indicated that they decided to continue hydrolasing for 30-45 minutes after noticing the absence of water flow because they mistakenly thought there was no water in the bowl to remove. No licensee organizations were involved in making this decision. The inspector concluded that while the consequences of this dilution were minimal, the control over the hydrolase process by the licensee and the configuration of the suction tube inside the SG bowl was inadequate. The licensee acknowledged the inspector's observation and initiated an Incident Investigation (3-1-90-024) to determine appropriate corrective actions.

No violations of NRC requirements or deviations were identified.

11. Steam Generator (SG) Tube Leak - Unit 1 (93702)

On April 24, 1990, a primary-to-secondary tube leak was discovered in the No. 2 SG. After cooling down, depressurizing and draining to mid-loop in the RCS, the leak was identified to be a leaking tube plug weld in location Row 2, Column 187. This location is in the corner of the hot leg against the divider plate. Directly below the plug is a bolt head and a "patch plate" that holds the divider plate in place. There is only approximately 2 inches of vertical clearance below the leaking tube plug. The plug was removed and replaced with a Combustion Engineering (CE) welded plug which is made of the same material as the weld overlay cladding on the primary side of the tube sheet. The licensee also fabricated several SG tube plug weld coupons to qualify welders for this process in the SG mockup. The welders attempted to duplicate the weld failures without success. One theory postulated by CE is that if there is insufficient contact force between the tube sheet and the plug skirt that the welding process will put high thermal stress across the skirt which can cause it to crack. The replacement plug leaked, so it was removed and replaced with another CE welded plug. The second replacement plug also leaked and was removed.

Further weld testing led the Engineering Evaluation Department ISI/NDT Engineers to theorize that the leak was occurring due to gas pressure building up underneath the weld between the plug and the tube. To counteract this a thicker skirt (0.080 inches) was specified. A custom plug was designed and fabricated on site. It too was installed and found to leak as well. The custom plug was removed and the licensee finally achieved an apparently successful weld by milling the tube sheet for insertion of a CE tube sheet plug which is larger and of a slightly different configuration than the previously used plugs. Through the process of pressurizing the secondary side of the steam generator to check for leaks, the licensee identified three adjacent plugged tubes which were leaking. These plugs were removed and replaced. The root cause of failure Engineering Evaluation Request (EER) 90-RC-94 identified these four tubes as having had a common history of leaking plugs which were reworked in November 1987 and first plugged in February 1987. The licensee concluded that multiple welding attempts in the restrictive location probably caused slight fitup anomalies with the plugs which resulted in welding defects. Three of the four tubes have now been milled and oversized tube sheet plugs were used. The remaining tube could not be milled, due to its proximity to the divider plate. The inspector concluded that the licensee's actions and evaluation's appeared appropriate.

No violations of NRC requirements or deviations were identified.

12. Inadvertent Reactor Coolant System (RCS) Fill Flowpath - Unit 1 (93702)

While restoring from the Low Pressure Safety Injection (LPSI) Section of 73ST-1XI09, Section XI, "Check Valve Operability and Position Indication Verification - Mode 1 Thru 4 CT, SI and HP "A" Train" surveillance procedure, the operator shut the LPSI "A" suction valve, SIA-683, and then opened the shutdown cooling

bypass-warmup valve SIA-691 without allowing sufficient time for SIA-683 to go fully closed. During the transition when both valves were partially open, a flow path existed from the Refueling Water Tank (RWT) to the RCS. Reactor Water Level Indication System indications increased from approximately 150 to 168 inches, which is an increase of approximately 800 gallons. Since the RWT is borated to at least 4,000 ppm no RCS boron dilution occurred. The level did not increase enough to spill water out of the open pressurizer manway. There was no impact on plant operations. The Operations Department has issued a night order alerting operators to these unexpected flowpaths. This night order was also sent to the Operations Departments at Units 2 and 3. The Operations Department also implemented an interim measure to put plexiglass covers over SI-690/691 to remind operators of the unexpected flowpath which is not represented by control board mimic lines. These plexiglass covers were not utilized at Units 2 or 3. The licensee initiated a review of this event by the Training Department to evaluate the potential need for changes to Operator Training after the inspector questioned the Training Department on this issue. The Operations Department submitted a Plant Change Request (PCR) to Engineering to add mimic lines to the control board to show this flowpath. This PCR will be evaluated at a future Plant Modification Committee meeting. The inspector concluded that these actions appear appropriate.

No violations of NRC requirements or deviations were identified.

13. Shutdown Cooling Throttle Valve Design Deficiency - Unit 1 (93702)

While cooling down with the reactor coolant pumps operating and the shutdown cooling system in service, the shutdown cooling heat exchanger outlet valve SIA-657 torqued out at approximately 15 percent open when the valve was being closed. The operators are directed in Operating Procedure 410P-1SI01, "Shutdown Cooling Initiation," to throttle downstream valves SIA-635/645 to reduce the differential pressure across SIA-657 if the differential pressure across SIA-657 results in a failure of the valve to move due to motor torque out. Licensee management questioned the appropriateness of this design. An Engineering Evaluation Request (EER 90-SI-94) was initiated to evaluate whether this butterfly valve should be used as a throttle valve and what flow conditions are appropriate. In certain circumstances reducing flow would not be permitted due to Technical Specification limitations. The inspector concluded that this valve operator configuration represents a design deficiency which makes shutdown cooling system operation difficult. The licensee agreed and is evaluating the feasibility of replacing the operator with one capable of higher torque.

No violations of NRC requirements or deviations were identified.

14. Reactor Coolant Pump (RCP) "1B" Breaker Trip - Unit 1 (93702)

On April 15, 1990, during replacement of the 13.8KV General Electric Magne-Blast breaker for RCP "2B," the electricians jarred the adjacent cubicle containing the breaker for RCP "1B" with enough force to cause it to trip. RCP "1B" was operating at the time and the plant was in Mode 5 preparing for Mode 4 entry. It was subsequently determined that the protective relays for all reactor coolant pump breakers are extremely sensitive to physical vibration and it is probable that the vibration resulting from jarring the RCP "1B" breaker cubicle caused the breaker to trip. Sufficient force was used to install the "2B" breaker that the noise resulting from the installation of the 2B breaker was loud enough to mask the sound of the "1B" breaker tripping. The electricians did not notice that the "1B" breaker had tripped while they were working in the adjacent cubicle. The "1B" RCP was meggered, the "1B" RCP breaker and relays were inspected by electricians and engineers. Since no problems were noted, the "1B" RCP was restarted and run without incident. An incident investigation (3-1-90-19) was performed and concluded that the electricians were the likely cause of the "1B" RCP breaker trip. An Electrical Shop Briefing Memo was prepared and sent to the other units and central maintenance was to advise all electricians to use "extreme care" when inserting the 13.8KV breakers into its cubicles. Engineering Evaluation Request 90-NA-009 was also initiated to evaluate the feasibility of using the electrical transport device discussed in the vendor technical manual. It appears, however, that although four such devices are available on site, General Electric no longer supplies breaker electrical transport devices. The inspector agreed with the Incident Investigation Report conclusion that "extreme care" is necessary when working near RCP breakers to prevent this potential for reactor trips and possible safety system actuations.

No violations of NRC requirements or deviations were identified.

15. Refueling Water Tank (RWT) Stratification - Unit 1 (93702)

On April 17, 1990, the unit entered the Action Statement for Limiting Condition for Operation (LCO) 3.5.4 after two RWT Boric Acid (BA) samples were less than the LCO value of 4,000 ppm. After thorough mixing using the High Pressure Safety Injection (HPSI) system, the final BA sample results were 4,009 and 4,124 ppm and the Action Statement was exited.

The Unit 1 Plant Manager asked the Independent Safety Engineering Group (ISEG or ISE) to evaluate the RWT scenario to determine if stratification had occurred and provide recommendations. On May 19, 1990, ISE submitted Engineering Evaluation Request (EER) 90-CH-067 to the Engineering Evaluation Department (EED) requesting EED to evaluate whether the current RWT sampling program results reflect actual RWT inventory. The EER was accompanied by draft ISE Special Investigation Report 90-04. ISE Special Investigation Report 90-04 did not reach any firm conclusion, suggesting only that there was evidence of stratification. The recommendation section only stated that all three plant managers had reviewed and agreed with the content of the report and that the EER needed to be answered. The

requested EER evaluation appeared to be answered by the facts gathered in the ISE report. The inspector questioned the adequacy of the ISE report conclusions and recommendations since the only apparent action to be completed was for EED to confirm ISE's statements that the sampling methods did not reflect actual RWT inventory. Nothing in the ISE report either resolved or initiated resolution for questions associated with the physical mechanism of stratification, the rate at which it occurs, the significance with respect to plant operation, or actions needed to ensure continuing operability of the RWT. ISE asserted that they are working with Engineering to ensure that the right questions get addressed to resolve this problem. The ISE report stated in conclusion No. 12 that while the low RWT boric acid concentration results were below Technical Specification limits, this concentration "still provides a positive margin to ensure reactor shutdown if RWT water were added to the RCS." This was based on Updated Final Safety Analysis Report (UFSAR) estimated RCS Boric Acid concentrations needed for criticality and 5 percent subcriticality at hot zero power at 565 degrees F with all Control Element Assemblies out. The inspector noted that this assumes hot RCS conditions. This assertion failed to account for the T/S LCO 3.5.4 basis for RWT concentration to ensure that ..."(2) the reactor will remain subcritical in the cold condition following mixing of the RWT and RCS water volumes..." (emphasis added). The licensee acknowledged the inspector's observations. The licensee also asserted that ISE will take an active, aggressive role in seeing that EER 90-SI-108 resolves this issue. (Inspector Followup item 528/90-20-03).

No violations of NRC requirements or deviations were identified.

16. Inadvertent Shutdown Cooling (SDC) Bypass Flow - Unit 1 (93702)

To shift flow from the SDC warmup/bypass line to the reactor coolant system loop, Shutdown Cooling Operating Procedure, 410P-1SI01, directs the operator to gradually jog valve SI-691 closed and valves SI-635/645 open for Train "A" and jog valve SI-690 closed and valves SI-615/625 open for Train "B". The design of valves SI-690/691 is such that the closed limit switch interrupts power to the valve operator and relies on the remaining valve inertia to drive the valve fully into its seat. When the valves are gradually jogged closed per 410P-1SI01, the inertia is insufficient to fully seat valves SI-690/691. This results in flow which bypasses the core but which is measured by the instruments the operators use to satisfy the minimum SDC flow requirement of Technical Specification 4.4.1.4.2 and also used for Reactor Water Level Indication System flow compensation. There are no installed flow instruments which would indicate the amount of bypass flow. Procedure 410P-1SI01 has been revised to require an operator to manually verify SI-690/691 shut whenever it is jogged shut per the procedure. In addition, Engineering Evaluation Request (EER) 90-SI-093 was issued to evaluate whether the existing controls are adequate to ensure that bypass flow does not occur. The inspector questioned the Nuclear Engineering Department (NED) Supervisor responsible for responding to this EER as to whether this evaluation would include the

historically poor correlation between the local valve position indication and actual valve position as well as the postulated condition where higher stem torque may suggest to an operator that the valve is closed when it is not fully seated. The NED representative stated that these questions would be addressed in their evaluation. The inspector concluded that this is a system design deficiency with the potential for impacting safety system operation and will monitor the licensee's activities in this area. (Inspector Followup Item 528/90-20-04). The licensee agreed and is evaluating these concerns in the resolution of EER 90-SI-093.

No violations of NRC requirements or deviations were identified.

17. MOVATS Testing - Unit 1 (92701 and 93702)

As a result of industry experience the Engineering Evaluation Department (EED) reviewed the historical Motor Operated Valve Acceptance Testing (MOVATS) data and concluded that four valves had possibly been overstressed during MOVATS testing. This occurred when the valves were adjusted to meet closing times, however the vendor recommended maximum thrust values were not incorporated. The valve which had potentially experienced the highest opening thrust of the four valves, SI-609, was disassembled and inspected. Slight deformation was observed on the gate where the stem force was exerted. However, the valve manufacturer examined the valve and stated in a letter dated April 16, 1990, that no major discrepancies existed and recommended operating one additional cycle with the existing valve and replacing the stems and gates on all four valves at the next refueling. The inspector examined MNCR 90-SI-0007 and its conditional release, and the vendors analysis and recommendations, and concluded the licensee's actions were consistent with their administrative requirements.

No violations of NRC requirements or deviations were identified.

18. Turbine Driven Auxiliary Feed Pump (AFW) Steam Admission Valve Mis-Wiring - Unit 1 (93702)

On April 27, 1990, the ramp start circuitry for the turbine drive AFW pump AFA-P01 from valve SG-UV-134 was discovered to be landed on the wrong lugs inside the electrical connection box for SG-UV-134 during troubleshooting during turbine driven AFW pump testing. The incorrectly landed lugs were on lugs 10/10c when they should have been on lugs 2/2c. This resulted in multiple overspeed trip actuations and caused the AFW pump to fail its surveillance test. A review of prior work on the electrical connection box for valve SG-UV-134 revealed an error on the Determination/Retermination (Determ/Reterm) sheet for cable 1ESF-01AC1RO in Work Order No. 421856. On this Determ/Reterm sheet cable 1ESG-01AC1RO was logged as having been lifted and relanded on Rotor 1 Termination Point (PT) 10/10c. Drawing 01-E-SGB-001 shows that these leads should have been lifted and landed on Rotor 3 terminals 2/2c. The incorrect use of the determ/reterm sheet is considered a violation of NRC requirements in that licensee procedure requirements were not

followed. However, this licensee identified violation is not being cited because the criteria specified in Section V.G of the Enforcement Policy were satisfied. The wiring error was corrected, and the AFW pump was retested, passing the surveillance test. The licensee counseled the electrician who made the mistake and is planning to issue a shop memo and hold a shop briefing to instruct electricians to double check their Determ/Reterm log entries with the cables before lifting leads.

The inspector discussed the requirements of ANSI N18.7-1976 with the licensee's Quality Control Manager. The current program requires an independent verification of the landing of leads per the Determ/Reterm sheet entries logged by the worker who lifted the leads but does not require independent verification of the Determ/Reterm sheet entries when the leads are lifted to ensure the entries are correct. The licensee also does not have a requirement for a Quality Control Inspector to verify the post maintenance wiring with plant design documents. Licensee management stated that current program requirements will be reviewed with regard to ANSI N18.7-1976. The inspector concluded that further licensee review of how independent verification is performed appears warranted.

19. Loss of Shutdown Cooling While Preparing for Mid-Loop Operations - Unit 1 (93702)

On May 8, 1990, at 8:00 PM (MST), Unit 1 entered reduced inventory operations in accordance with procedure 41OP-1ZZ16, "RCS Drain Operations." At 1:11 AM on May 9, "A" Train Shutdown Cooling Flow was inadvertently lost when the pump suction valve SIA-UV-655 went shut while I&C Technicians were in the process of defeating the auto closure pressure interlock on the suction valve. During removal of the auto interlock electrical leads, the I&C Technicians inadvertently shorted the positive and negative leads which caused the closure. The Primary Reactor Operator tripped the "A" LPSI pump before suction was completely lost.

The Primary Reactor Operator was directed to restore shutdown cooling using "B" Train. However the "B" Train Shutdown Cooling pump suction valve SIB-UV-656 was discovered to be closed also. Both the "A" and "B" Train pump suction valves were reopened from the Control Room. At 1:17 AM, "B" Train Shutdown Cooling started supplying water to the core and at 1:28 AM, shutdown cooling flow greater than 4,000 gpm was restored.

During the time shutdown cooling was lost, RCS level increased as a result of the continued charging from Charging Pump "E". At 3:15 AM, the Plant Manager directed that level be increased to a level greater than reduced inventory operations pending an investigation of the event.

The licensee initiated Incident Investigation Report 2-1-90-1 to evaluate this event. The licensee concluded that the cause of the "B" Train valve being shut was the same as the "A" Train. They determined that approximately 14 minutes prior to the "A" Train

valve going shut, technicians had performed the same work on the companion "B" Train valve. Through testing and document reviews, the licensee determined that there was no common mode relationship between both valves going shut, such that a single failure or event would cause a total loss of cooling flow. They concluded that improvements could be made in the methods used for defeating the interlocks and in the timing of when each train is defeated such that a train was not operating when defeating interlocks associated with that train and that the plant was not in a reduced inventory status.

The inspector considered that the core had minimal decay heat and that RCS level was several inches above the hot leg. During the 17 minutes that shutdown cooling was lost only a three degree RCS temperature rise occurred. However, in a reduced RCS inventory condition and with a core with greater decay heat, there is a substantial increase in the risk of boiling in the core and subsequent core recovery upon a loss of shutdown cooling flow. The licensee had addressed NRC concerns in this area in their responses to Generic Letter 88-17 (GL-88-17). The inspector examined these responses and determined that, in the program enhancement area, the licensee committed to maintain participation in a generic CE Owners Group on the study of eliminating automatic closure interlocks for SDC suction valves. A determination had not yet been made at the time of this incident. The inspector concluded that although the licensee was meeting their commitment, further consideration needed to be given to alternative methods for defeating interlocks while in reduced inventory status. The licensee reached a similar conclusion and initiated Quality Deficiency Report 90-182 to evaluate possible solutions. The inspector further reviewed the licensee's compliance with Technical Specification 3.4.1.4.1 concerning shutdown cooling system operation and concluded that the licensee met action statement requirements to immediately initiate corrective action to return a shutdown cooling loop to operation.

The inspector concluded that the licensee's investigation adequately identified the technical issues involved with the difficulty of physically lifting the leads to defeat the interlocks in that the leads were adjacent to each other on the terminal block without insulating material between, and also identified possible improvements in the procedure such that interlocks would be defeated without risking loss of shutdown cooling flow. Based on the disposition of QDR 90-182, the licensee changed procedure 4XOP-XZZ16 for all units to require interlocks to be defeated prior to entering a reduced inventory condition if the final condition will be mid-loop operations. In addition, the power supply to each valve will be disconnected during the time the interlock is defeated. Finally, each valve position will be verified after power is restored. The inspector concluded that these actions appeared appropriate.

The inspector reviewed IIR 2-1-90-1 and questioned whether the operation crew's performance was adequately assessed. Operators failed to notice the change in position of the "B" Train valve for

approximately 14 minutes until the loss of flow occurred and they took action to initiate "B" Train cooling flow. Licensee management acknowledged this observation and stated that the operators had been counseled and that this aspect of the event would be reviewed by licensed operators during scheduled training. The inspector concluded that operators' response following the event was satisfactory.

No violations of NRC requirements or deviations were identified.

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

The inspectors reviewed a selected portion of the completed restart action items committed to by the licensee for the restart of Unit 1. This review was still in progress at the end of the inspection report period and will be documented in the next resident inspectors' inspection report.

21. Refueling Activities - Unit 2 (60710)

During this reporting period, several minor refueling related anomalies occurred, all identified and corrected by the licensee.

a. Fuel Reload

Fuel reload began May 13, 1990. Early during the reload, several delays were incurred while adjusting the lighting at the bottom of the reactor vessel to improve the ability to monitor proper seating of the assemblies as they are loaded. The licensee had committed to provide lighting in the lower core area to help detect mechanical binding between assemblies. While lighting was adequate for this purpose before fuel was loaded, licensee management chose to enhance lighting so as to be able to observe seating of the assemblies over the alignment pins.

Assembly 67 could not be properly seated in its correct orientation due to being slightly bowed. The licensee chose to rotate the assembly 180 degrees until it was boxed in by other assemblies, and was subsequently successfully repositioned to its correct orientation. The licensee determined that this rotation did not reduce shutdown margin below acceptable limits while the assembly was in a condition other than final core configuration.

The core reload was completed on May 20, 1990. During core mapping it was discovered that the assembly in location E03 was in the correct core location, but mis-oriented by 90 degrees. The licensee properly repositioned the assembly. The core verification was completed on May 21, 1990, without further incident.

b. Cavity Seal

On about May 20, 1990, the licensee observed air bubbles in the refueling pool indicating an air leak on the hose supplying the refuel cavity seal. The design of this seal is such that the hydrostatic pressure of the water in the refueling pool alone is sufficient to create an adequate seal with the water level at least five feet over the seal. Below this level some leakage is anticipated, which would be collected in the cavity sump. The licensee chose to delay planned refueling activities involving lowering the water level until the leak was repaired. It was later determined that the supply hose had become disconnected from the seals. A diver successfully reconnected the hose.

The inspector reviewed the licensee's response to I&E Bulletin 84-03 regarding the failure of the Haddam Neck cavity seal and did not identify any related actions. The response classifies the pneumatic seal as secondary and the wedge (activated by hydrostatic pressure) as primary. The response does not address monitoring of the pneumatic seal pressure.

The inspector reviewed Auxiliary Operator logs for the duration of the outage to determine if trends in air pressure to the seals could have indicated the existence or extent of the leak. The logs show essentially uniform pressure (about 22-24 psig) for both inner and outer seals, except that after the hose was reconnected, both seal supply pressures were 30 psig. The acceptable band for these pressures is 20 to 30 psig. Because the pressure indicators are located just downstream of the regulator, they indicate supply pressure rather than seal pressure. In this configuration they do not provide direct indication of the integrity of the seal. The licensee stated that the seal should be monitored by observation for bubbles from the seal air supply system prior to each draining evolution. The licensee initiated an Instruction Change Request (ICR) to evaluate the adequacy of procedures in this respect.

c. Broken Incore Instrument

During removal of Incore Instrumentation (ICIs), one ICI was broken in the tube. The licensee carefully proceeded to remove the broken ICI by pushing it back up into the reactor vessel, bending it over and then hooking it. The process of pushing it out was not initially successful due to binding of the cable used for pushing inside the tube. Eventually a new ICI was modified for use as a pushing tool, which was successful.

No violations of NRC requirements or deviations were identified.

22. Broken Westinghouse Steam Generator Tube Plug - Unit 2 (93702)

During removal and replacement of potentially defective Westinghouse Steam Generator (SG) tube plugs identified in NRC Bulletin 89-01, one SG No. 1 tube plug (hot leg tube R78/L21) was found to be

broken. The cap from the plug was lodged in the tube near the upper part of the tube sheet. No damage to the tube itself was observed. The licensee determined that leaving the broken portion of the plug in the tube was acceptable. A stabilizer rod was inserted under the broken plug, a wear piece was installed above the top of a new plug, and the new plug was installed. Additionally, a new mechanical plug was installed in the cold leg end of the tube. The inspector reviewed the licensee's response to NRC Bulletin 89-01 and the 10 CFR 50.59 Safety evaluation for the configuration change. An NRC technical staff representative from NRR also reviewed the licensee's engineering evaluation and had no comments.

No violations of NRC requirements or deviations were identified.

23. Charging Pump Valve Misalignment - Unit 2 (93702)

On May 11, 1990, following maintenance on the "A" charging pump (CHA-P01), the pump was started without a suction or discharge flowpath established. The pump tripped a few seconds later due to low suction pressure. Following establishment of the desired flowpaths, the pump was successfully run with no apparent damage having resulted from the misoperation. The pump was not required to be operable at the time of the event because the plant was defueled.

During the week prior to the event, several valve lineups had been performed on portions of the Chemical and Volume Control (CVCS) system. These lineups consistently verified the "A" charging pump normal suction valve (CHA-HV-316) open, the "A" charging pump alternate suction valve (CHA-HV-755) shut and the "A" charging pump discharge valve (CHA-HV-339) shut. Even though the normal suction valve was open, this was not available as a flowpath because the Volume Control Tank (VCT) was empty and its discharge valve (CHA-UV-501) was shut. Both the "B" and "E" charging pumps were aligned to the alternate suction flowpath from the Refueling Water Tank (RWT). The Auxiliary Operator (AO) responsible for performing the prestart checks of the pump lineup, per Appendix C of 42OP-2CH01, "CVCS Normal Operations," did not perform the checks when directed, but asserted that the checks had been performed, based on previous observations during his routine tour of the three charging pump rooms. Also, he did not physically check the valves by turning the valves in the closed direction as required by licensee procedures. He did not have the procedure with him when he made the checks as required by licensee procedures, though he claims to have verified his observations with the procedure afterwards. He thought the discharge valve was open, even though its position indicator showed it was shut. He also confirmed the normal suction valve to be open as expected, though he should have recognized that the normal suction flowpath was not available.

The Control Room operators who directed the AO to perform the prestart checks did not recognize that the prestart check contained in 42OP-2CH01 does not address the alternate suction path. These checks are inadequate to independently assure proper system alignment when the CVCS system is not already aligned for normal

operations. The operators should have confirmed the adequacy of the prestart checks or utilized a special valve lineup to accomplish the intended function.

In reviewing this event, the licensee determined that the prestart checks for the Safety Injection system pumps are also possibly deficient because the alternate suction flowpaths are not considered. The licensee committed to evaluate the adequacy of these check lists. Additionally, the Shift Supervisor and AO involved were counseled regarding their performance, and a Human Performance Evaluation System (HPES) evaluation is being performed. The failure to check the valves in the manner described in licensee procedures, and the failure to refer to the procedure while performing the prestart checks, are apparent violations of NRC requirements. However, the violations are not being cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied.

24. Inadvertent Discharge of Carbon Dioxide - Unit 2 (93702)

On April 27, 1990, during routine carbon dioxide fire suppression system functional testing (Procedure 14FT-9FP08), an inadvertent discharge of carbon dioxide occurred in the "A" Train Engineered Safeguards Features (ESF) Switchgear Room. The discharge occurred as a result of inattention to detail in the performance of the test, in which the technician improperly capped the wrong line while attempting to test the pneumatic discharge timer for the extended discharge portion of the system. When the timer was actuated, an anticipated warning alarm sounded, and carbon dioxide was injected into the switchgear room for approximately 30 seconds. The licensee sent a team equipped with Self-Contained Breathing Apparatus into the area to search for any personnel who might have been in the affected area. No personnel were in the switchgear room at the time. Atmospheric monitoring demonstrated that oxygen levels in the affected room remained above 20.5 percent. The room was ventilated and a fire watch stationed until the fire suppression system was recharged and operable.

The licensee performed a Human Performance Evaluation System evaluation (HPES 90-021), which the inspector reviewed. While this issue has negligible nuclear safety significance, the licensee has acknowledged the substantial potential risk to personnel and has approached its corrective actions from that perspective.

No violations of NRC requirements or deviations were identified.

25. Inadequate Retest of Motor Operated Butterfly Valve - Unit 2 (93702)

On May 21, 1990, the Essential Cooling Water (EW) to Nuclear Cooling Water (NC) cross-connect valve (2EWA-UV-145) was found to be leaking by its seat, preventing restoration of the EW system to operable status. The EW system was not required to be operable at the time, because the plant was in Mode 6 with RCS water level greater than or

equal to 23 feet above the reactor vessel flange. However, operability was needed to support planned plant activities involving lowering the RCS level to less than 23 feet. The inspector determined that valve maintenance had been performed on under an Equipment Qualifications Preventive Maintenance (EQ PM) task (Work Order 374572) on May 19 and May 20, 1990.

The inspector questioned the thoroughness of the post-maintenance retest in that it allowed valve leakage. Subsequent to the inspectors questions. The licensee concluded that the retest was inadequate for the task performed. The task, identified in procedure 32MT-9ZZ48, "Maintenance of Limitorque Motor Operated Valves," involved adjusting the limit switches and mechanical stops for the valves. The retest, also specified in that procedure, verifies remote and local indication upon stroking the valve, verifying the valve is not hitting the mechanical stop nuts, and determining that electrical characteristics of the motor match the nameplate data. No leakage is monitored to verify actual valve seating. The licensee determined that this deficiency applies to the retest of all limitorque motor operated butterfly valves.

After discussing the EW and NC system characteristics with engineering and operations personnel, the inspector determined that any significant leakage through WEA-UV-145 would always be self-revealing during plant operation, causing EW and NC surge tank level alarms to annunciate in the Control Room. The inspector concluded that it would be unlikely for either EW Train to be unknowingly cross-connected to the non-class, non-seismically qualified NC system, resulting in EW Train inoperability, without operator awareness of the situation. The NC system is normally in service during plant operations, but the EW system generally is not.

The licensee committed to review the potential operability concerns associated with the inadequate retest of other motor operated butterfly valves. (Unresolved Item 50-529/90-20-01).

No violations of NRC requirements or deviations were identified.

26. Steam Generator (SG) U-Tube Mis-plugging - Unit 2 (93702)

a. 1988 Refueling

While performing Eddy Current Testing (ECT) of Steam Generator No. 2 (SG-22) U-Tubes during the 1990 refueling outage, one plug was found to have been installed in the wrong tube on the hot leg side during the previous (1988) refueling outage. The tube which should have been plugged had a 41 percent defect and was required to be plugged for the SG to be operable in accordance with Technical Specifications (T/S). The cold leg side of the tube had been properly plugged. This was reported to the NRC in Licensee Event Report 529/90-005 (See Paragraph 31).

The inspector reviewed the licensee's Incident Investigation Report (IIR) 3-2-90-009. The licensee determined that the mis-plugging was the result of personnel errors on the part of the 1988 plugging crew and the QC Inspector who certified that the correct tubes were plugged. Corrective action included instituting independent verification of the correct tube by the plugging crew and post-installation video verification by comparison of engineering drawings with the visual record.

The plant operated for one cycle with SG-22 inoperable, which is an apparent violation of T/S 4.4.4.4.b. The violation is not being cited because the criteria specified in Section V.G of the Enforcement Policy were satisfied.

b. 1990 Refueling

Following completion of plugging activities on SG-22 during the 1990 refueling outage, two tubes were found to have been mis-plugged. Two independent reviews were being performed in parallel, resulting in one mis-plugging being first identified by different organizations. During back-end review of Material Non-Conformance Report (MNCR) 90-RC-0013, a plug was found to have been installed in hot leg tube R95-L140 instead of in hot leg tube R85-L140. During engineering review of the video tape of the cold leg tube sheet, a plug was found to have been installed in tube R90-L51 instead of in R96-L51.

Both of these errors occurred due to mis-transposition of the plugging list from the MNCR into the Work Orders (WO 419483 and WO 419484). Following completion of ECT of the tubes, the plugging lists in the WOs were modified to include the additional 87 tubes found to be defective in SG-22. This additional work was not determined to constitute a change in scope, allowing the WOs to be modified via a "field change" procedure. In this process, a work planner makes a pen-and-ink change to the WOs, and a Quality Control (QC) Inspector reviews the change to insure adequacy of QC inspection points. QC management expects other aspects of the change to be checked also, but this did not occur. In this case, different planners and QC Inspectors were involved in the change to each WO. No independent verification of the change was performed.

Licensee procedure 30DP-9WP02, "Work Planning," requires "scope changes" to be implemented via the WO amendment process, which receives the same level of review as the original WO. This includes an independent technical review. As a corrective action, the licensee has committed to processing future additions to the SG tube plugging lists in WOs as scope changes, using the amendment process. The licensee considers the existing procedures adequate, and stated that sensitizing QC and maintenance personnel to this broader meaning of "scope change" for this application would suffice in ensuring adequate reviews in the future. The QC department has also established

a "Lessons Learned" file which inspectors will be required to review before commencing inspection activities.

No violations of NRC requirements or deviations were identified.

27. Reactor Coolant System Spill - Unit 2 (93702)

On April 27, 1990, while the reactor was defueled, approximately 2,500 gallons of water spilled out of the Reactor Coolant System (RCS) onto the containment floor while operators were attempting to fill and vent the "B" Train Containment Spray (CS) system. The filling was to be done by gravity feeding water from the Refueling Water Tank (RWT), through the Low Pressure Safety Injection (LPSI) "B" pump into the CS "B" header. When the Assistant Shift Supervisor (ASS) reviewed the system drawings, he failed to recognize the potential flow path from the Safety Injection (SI) system to the RCS via the Shutdown Cooling (SDC) warm up line. This line is normally isolated by valve 2SIB-HV-690. The line up was performed as a clearance restoration line up, and was discussed by the ASS, Shift Supervisor (SS) and Reactor Operator (RO).

About two hours after filling operations commenced and operations personnel were satisfied with plant conditions, the ASS gave permission for maintenance personnel to perform MOVATS testing on valve 2SIB-HV-690, fully recognizing that the valve would be cycled. When the valve was stroked open, water passed from the RWT into the RCS and spilled onto the floor via the Reactor Coolant Pump (RCP) seal injection connection (the RCPs were in various stages of disassembly at the time). When the leakage was reported to the Control Room, operators immediately closed valves 2CHB-HV-530, 2SIB-HV-692 and 2SIB-UV-654 to secure all viable flow paths and water sources to the RCS. This stopped the spill. The licensee then cleaned up the spill, which resulted in some equipment problems (RCP seal packages) but no personnel contaminations.

The inspector reviewed the licensee's Incident Investigation Report (IIR) 3-2-90-010. Immediate corrective actions included requiring establishment of positive administrative controls to preclude unplanned movement of water during MOVATS activities, independently verified system alignments for all clearance restorations involving filling of systems to establish system boundaries, and restrictions on removing valve operators for MOVATS testing. These interim actions were superseded by final corrective actions, which included evaluation of enhancing the control board mimic to show the SDC warm up line, briefing all Unit 2 operations crews, emphasizing to the SSs and ASSs the importance of attention to detail and finally, using independently verified valve alignments for restoration of clearances involving the filling of systems. This last corrective action is being evaluated by the licensee to determine if procedure changes are appropriate for permanent implementation.

The IIR conclusions and final corrective actions do not address the issue that operations personnel did not maintain awareness of plant systems as affected by MOVATS activities, however the interim

corrective actions provided additional controls in this area. The inspector noted that operations now uses plastic "MOVATS" tags on the control boards, in addition to caution tags to indicate valves being worked by MOVATS crews. Additionally, the Unit 2 Operations Manager issued a Night Order emphasizing the need for operations to maintain control over system boundaries during maintenance by either 1) issuing clearances to prevent maintenance activities from impacting operations unexpectedly, 2) operations maintaining direct control over system components, or 3) allowing maintenance to have component control, but having a dedicated operator to maintain cognizance of the specific maintenance activity.

The IIR does not address the concepts emphasized in the Night Order. The licensee stated that the night order reflects a philosophy consistent with management expectations, and that it adds emphasis to direction already contained in existing procedures. The licensee is evaluating operating procedures to determine if revisions are necessary or appropriate to clarify this management philosophy.

No violations of NRC requirements or deviations were identified.

28. Atmospheric Dump Valve (ADV) Nitrogen Accumulator Found Isolated - Unit 3 (93702).

On April 22, 1990, Unit 3 operators received a low nitrogen pressure alarm on the accumulator for ADV 185. Upon investigation, the operations crew determined that accumulator outlet valve SGE-V363, which was supposed to be locked open, according to Control Room records, was found locked closed. At the time of this occurrence, Unit 3 was in Mode 1. The licensee's immediate action was to open valve V363 and verify all other ADV locked valves. No other discrepancies were identified.

The licensee performed an investigation (HPES 90-20) and determined that on April 16, 1990, operators had last positioned valve V363 during performance of a maintenance test procedure to check ADV bonnet pressures. It was concluded that despite the licensee's requirement for independent verification of this valve, operators failed to correctly check its position at the conclusion of the test and thus had incorrectly locked it and documented it in the open position.

The isolation of the nitrogen supply removed the only quality related source of operating pressure from ADV 185 for remote operation. This rendered the valve inoperable pursuant to Technical Specification (T/S) 3.7.1.6. Since the Action Statement allows continued operation with only one operable ADV per Steam Generator (SG), no actual loss of safety-related ADV capability occurred.

The inspector noted that licensee procedure 43DP-30P01, "Manual Operation of Air Operated Valves," requires that SGE-V363 be restored for remote operation by utilizing 40AC-00P06, "Locked Valve and Breaker Control," which requires (Section 3.3.1) independent verification of this valve per 02AC-0ZZ01, "Independent Verification of Valves, Breakers, and Components," which requires (Section 3.4.6.1) that valves be checked open by manipulating in the closed

direction. Thus, prior to lock wiring the valve in its final position, the valve should be physically verified, by partial operation, to be open. Documentation of the repositioning and the independent verification of its open position was inaccurately made in the Control Room record for locked valves by the operators performing the lineup. This is considered an apparent violation of NRC requirements (530/90-20-01).

The inspector further noted that an identical condition was discovered in Unit 1 on April 10, 1989, wherein ADV 178 was discovered to be inoperable (NRC Inspection Report 528/89-16) and an NRC Notice of Violation was issued. The licensee's corrective action at that time included changing procedures to require locked valve controls and independent verification to be applied to important ADV nitrogen system valves. This corrective action was fully in place at the time of the present incident. In addition, the NRC Diagnostic Evaluation Team (DET) report dated March 16, 1990, (Section 3.2.3.8) observed a weakness in the independence of independent verification (IV) techniques and concluded that the licensee's IV program was weak.

Based on a review of the licensee's investigation, the inspector agreed with the licensee's conclusion that in this case independent verification was inadequate due to operators not following the guidelines of 02AC-0ZZ01. The inspector further concluded that this was an additional example of the IV program weakness discussed in the DET report. The licensee's corrective action included issuing a letter to all unit operations managers emphasizing the importance of proper IV techniques required by 02AC-0ZZ01, and referenced the addition of IV training for Auxiliary Operators in continuing training classes. Finally, the inspector noted that one of the two operators was a licensed Control Room Operator, and was apparently not setting an appropriate example for the auxiliary operators.

The licensee management acknowledged the inspector's comments.

One apparent violation of NRC requirements or deviations was identified.

29. <u>ECCS Pump Room Material Control - Unit 3 (71710).</u>

On May 17, 1990, while conducting a walkdown of the High Pressure Safgety Injection (HPSI) system, the inspector noted a Radioactive Material Storage Area (RMSA) had been established in the "B" HPSI pump room. Within this area were 3 tagged bags of pump insulation material that had been apparently stored there since January 24, 1990, awaiting completion of certain tests on the pump. The inspector noted that the licensee's FSAR paragraph 6.3.1.4.c.3 states that the maximum pipe break outside of containment would not interfere with ECCS pump operation due, in part, to the draining of flood water through the ECCS pump room sumps. The licensee confirmed that design calculations 13M-ZA-805 and 809 take credit for these sumps during postulated flooding. The inspector noted that the stored material represented a potential threat to assumed sump

operation if flooding were to cause this material to be transported to the sump and partly or fully block its opening. The licensee does not have any administrative or program controls to specifically control transient material in ECCS pump rooms with respect to potential impact on the sumps. The licensee removed the material from the identified area and verified other ECCS pump rooms were not similarly affected. They further commited to evaluate the nature and extent of any necessary controls. This is an Inspector Followup Item (530/90-20-02).

30. Temporary Instruction (TI) 2515/104: Fitness for Duty (FFD) Initial Training Programs - Units 1, 2, and 3 (2515/104)

This report entry is to administratively close TI 2515/104. The inspector attended three Fitness for Duty (FFD) training sessions held by the licensee. On December 7, 1989, the inspector attended a presentation to the Training Department covering FFD Policy and Awareness. On December 20, 1989, the inspector took a self-paced computer presented training and testing program specifically for persons authorized to be escorts within the protected area. The inspector noted that all licensee employees who have access to the protected area are possible escorts and that the FFD escort training has been incorporated into routine site access training requirements. Finally, the inspector attended a presentation given for Supervisors on February 27, 1990. The inspector concluded that the presentations were generally complete and thorough, and offered ample opportunity for questions to be raised and answered. The inspector had no further questions.

No violations of NRC requirements or deviations were identified.

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

The following LERs were reviewed by the Resident Inspectors.

Unit 1:

a. 528/84-01-LO (Open) "Fire Barrier Penetration Seals"

This LER was statused in Inspection Report 50-528/89-54 with two Engineering Evaluation Requests (EER) which needed to be closed. EER 89-FP-37 has been closed; however, 89-FP-139 remains open. According to the Nuclear Engineering Department (NED) engineer responsible for closing 89-FP-139, this resolution will require a 100 percent inspection of all 10 CFR Part 50 Appendix R fire barrier penetration seals. By separate correspondence on March 16, 1990, ANPP communicated a Fire Protection Action Plan which contains a schedule for performing these inspections. According to NED, these inspections will be 100 percent inspection and data gathering. Once all the data is obtained, the design requirements will be compared to the as built configurations, an evaluation will then be performed, and if design documents or seals have to be changed, the changes will be made promptly. This item remains open.

b. 528/89-10-LO (Closed) "Main Steam Safety Valve Setpoints Discovered Out of Tolerance"

This licensee event describes failures of Main Steam Safety Valves (MSSV) to meet their Technical Specification (T/S) setpoint tolerance. The licensee adjusted the valves and achieved three satisfactory lifts within the required tolerance. The requirement for testing these valves had been once every five years. The testing frequency has been increased to once per refueling until satisfactory performance is achieved. The licensee is also performing an Engineering Evaluation to evaluate the feasibility of changing the T/S to increase the tolerance on MSSV setpoints. The licensee acknowledged that the existing T/S will be met until a license change is approved. This LER is closed.

c. 528/89-19-LO (Closed) "Engineered Safety Feature (ESF) Actuation Caused by Loose Connection"

This licensee event describes an ESF actuation caused by a loose connection between a radiation monitor remote indication and control unit drawer and cabinet. The plug was secured in place and surveillance tests were completed satisfactorily. All ESF equipment operated as designed. This LER is closed.

d. 528/89-20-LO/L1 (Closed) "Voluntary Report of Load Sequencer Actuation"

This licensee event describes an inadvertent load sequencer actuation including an emergency diesel generator start. This event was addressed in Inspection Report 50-528/89-36. The procedure change described in the licensee event report is complete. This LER is closed.

e. 528/89-22-LO (Closed) "Fuel Building Ventilation Low Range Effluent Monitor Alarm Not Properly Investigated"

This licensee event described a Control Room alarm which was received but not investigated. As a result, Action Statement Requirement 40 of Technical Specification 3.3.3.8 was not met. The cause of the alarm appeared to be the low flow limit switch drifting from its desired position. This was investigated and reported in Special Report 2-SR-89-007. The cause of the failure to investigate the Control Room alarm was investigated and corrective action taken. This LER is closed.

f. 528/89-23-LO (Closed) "Ventilation Turning Vanes Not Seismically Qualified"

This licensee event referred to seismic deficiencies in the essential auxiliary building and Engineered Safety Feature (ESF) equipment room ducts which rendered these ventilation systems inoperable. The licensee verified that the normal ventilation systems would maintain the original air temperatures then added braces on the ducts to stiffen them to meet seismic requirements.

Additional deficiencies identified in this LER included an inadequate administrative program to ensure that significant conditions were escalated to management for appropriate disposition. The corrective action for this concern is primarily the new Material Non-Conformance Report (MNCR) program which was used in the rediscovery and resolution process for this seismic issue. The LER is closed.

g. 528/89-24-L0/L1 (Closed) "Engineered Safety Feature Actuation During Reactor Coolant Pump Test"

This licensee event involved an ESF actuation which occurred due to a radiation monitor trip during a reactor coolant pump (RCP) motor start with the 1E battery disconnected from the essential DC bus. The radiation monitor tripped due to a voltage fluctuation on the essential DC bus. The long term corrective actions were to revise RCP and circulating water pump operating procedures to warn operators of the potential for power fluctuation or interruptions if these large motors are started with 1E batteries disconnected. The LER is closed.

Unit 2:

a. 529/89-002-L0 (Closed) "Main Steam Safety Valve Setpoints Discovered Out-of-Tolerance"

This LER is closed based on actions taken for a similar event reported in LER 528/89-010, and documented in this report.

b. 529/89-003-L0/L1 (Closed) "Reactor Trip Due To Low Steam Generator Level"

This report describes the February 16, 1989, trip of Unit 2 caused by feedwater control system problems. A Safety Injection Actuation and Containment Isolation Actuation occurred due to overcooling of the Reactor Coolant System during the event. While the root cause of the event was determined to be debris in the economizer valve pneumatic positioner, the response to the event was complicated by improper connections within a digital recorder being used to troubleshoot previously observed feedwater control system perturbations. The corrective actions as described in the report appear to be adequate. This LER is closed.

c. 529/89-007-L0 (Closed) "Main Steam Safety Valve Setpoints Discovered Out-of-Tolerance"

This LER is closed based on actions taken for a similar event reported in LER 528/89-010, and documented in this report.

d. 529/90-005-L0 (Closed) "Operation With Steam Generator U-Tube Not Plugged As Required By Technical Specifications."

This event is described in paragraph 24.a, which also describes enforcement conclusions. The LER is consistent with information

obtained from source documents reviewed by the inspector. This LER is closed.

Unit 3:

a. 530/90-003-LO (Closed) "Emergency Diesel Generator Inoperable Due to Painting."

This LER resulted from the discovery, by a licensee System Engineer (SE), that painters had allowed paint into the fuel metering rod ports during painting of the Emergency Diesel Generator (EDG) "3A". The SE was conducting an EDG walkdown due to the painting in progress, after having conducted a pre-job briefing with the painters' foreman. The pre-job briefing specifically covered areas which were not to be painted, but the painters apparently did not fully understand that the fuel metering rod parts must remain free of paint. The licensee determined that the cause of the event was poor communication from the painter foreman to the painters.

The inspector noted that the SE walked down the EDG only one day after the affected area was painted. Thus the SEs initiative to stay close to a maintenance task prevented the condition from going unnoticed or lasting beyond one day.

The licensee's actions included halting work while further, more detailed briefings were held with the painters, foreman, SE, and work planner. A new work order was developed with more specific guidance, including pictures, regarding areas not to be painted. The licensee is studying further actions to improve future similar work orders. This LER is closed.

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

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

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

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

Unit 1

- Monthly Operating Report for April 1990.

Unit 2

- Monthly Operating Report for April 1990.

Unit 3

o Monthly Operating Report for April 1990.

No violations of NRC requirements or deviations were identified.

33. Exit Meeting (30703)

The inspector met with licensee management representatives periodically during the inspection and held an exit meeting on May 31, 1990.