U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-528/91-01, 50-529/91-01 and 50-530/91-01

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: January 6 through February 16, 1991

Inspectors:		
	D. Coe,	Senior Resident Inspector
	F. Ringwald,	Resident Inspector
	J. Sloan,	Resident Inspector
	D. Kirsch,	Chief, Reactor Safety Branch
	W. Ang,	Project Inspector

Approved By: H. J. Wong, Chief
Reactor Projects, Section II

3/20/91
Date Signed

Inspection Summary:

Inspection on January 6 through February 16, 1991 (Report Numbers 50-528/91-01, 50-529/91-01, and 50-530/91-01)

Areas Inspected: Routine, onsite, and regular and backshift inspection by the resident inspectors and inspectors from the Region V staff. Areas inspected included: previously identified items; review of plant activities; monthly surveillance testing; monthly plant maintenance; reactor coolant system (RCS) cooldown rate limit exceeded - Unit 1; apparent reactor coolant system (RCS) stratification in loop 1 hotleg - Unit 1; incorrect lube oil added to auxiliary feedwater pump and boric acid makeup pump - Unit 2; emergency diesel generator air start system leakage - Unit 3; violation of surveillance requirement to perform emergency diesel generator (EDG) inspections during plant shutdown - Unit 3; use of an engineering evaluation (EER) request not formally approved - Unit 3; potential for small break LOCA due to tube rupture in the reactor coolant pump seal cooler - Units 1, 2, and 3; Probabilistic Risk Assessment - Units 1, 2, and 3; Plant Review Board activities - 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: 30703, 40500, 61726, 62703, 71707, 71710, 92700, 92701, 92702 and 93702.

Results: Of the 15 areas inspected, two violations were identified in Unit 3. The violations pertained to an NRC identified departure from the plant conditions specified for performing an Emergency Diesel Generator surveillance inspections and the failure to promptly correct an identified deficiency and perform an adequate evaluation of the deficiency.

General Conclusions and Specific Findings

Significant Safety Matters:	None
Summary of Violations:	2 Cited Violations - Unit 3
Summary of Deviations:	0
Open Items Summary:	7 Items closed, 3 Items left open, and 6 New Items opened.

DETAILS

1. Persons Contacted:

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

Arizona Public Service Company (APS)

*R. Adney,	Plant Manager, Unit 3
*J. Auston,	Fire Department, Deputy Chief
*J. Bailey,	Vice President, Nuclear Safety & Licensing
*H. Bieling,	Emergency/Fire Protection, Manager
#*T. Bradish,	Compliance, Manager
*M. Czarnylas,	Fire Protection, Deputy Chief
*J. Draper,	SCE, Site Representative
*E. Dotson,	Engineering & Construction, Site Director
#*T. Engbring,	Lead Engineer, Systems Engineering
*R. Flood,	Plant Manager, Unit 2
R. Fullmer,	QA and Monitoring, Manager
D. Gouge,	Plant Support, Manager (Ch. Plant Review Bd.)
#*S. Guthrie,	Quality Department, Deputy Director
*K. Hall,	El Paso Electric Co., Site Representative
*B. Hazelwood,	Quality Assurance, Monitoring, Supervisor
*R. Henry,	Salt River Project, Site Representative
P. Hughes,	Site Rad. Protection, General Manager
*W. Ide,	Plant Manager, Unit 1
*S. Kanter,	Sr. Coordinator, Owner Services
F. Larkin,	Security, Manager
*J. Levine,	Vice President, Nuclear Power Production
J. Minnicks,	Maintenance Manager, Unit 3
*J. Napier,	Compliance, Lead
*G. Overbeck,	Technical Support, Site Director
*R. Rouse,	Compliance, Supervisor
R. Rogalski,	QA, Supervisor
J. Scott,	Operations Manager, Unit 1
#G. Shell,	Quality Systems, Manager
S. Terrigino,	Management Services, Supervisor
#N. Thibodaux,	System Engineer, EDG System

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 February 21, 1991.

#Persons contacted by W. Ang.

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

A. Unit 1:

1. (Closed) Unresolved Item (528/90-20-01): "RCP Lube Oil Collection System Tubing" - Unit 1 (92701)

This item involved improper restoration of RCP lube oil collection system tubing following replacement of the RCP motors. The inspector questioned the requirements for quality control classification and controls over this piping. The licensee has classified the RCP lube oil collection system tubing as Quality Augmented (QAG) and is finalizing the specific requirements as part of the Fire Protection Task Force effort. The licensee is also correcting the deficiency in procedure 31MT-9RC06, "Reactor Coolant Pump Disassembly and Reassembly" to include steps for restoring this tubing and will include references to the drawings and documents required for proper installation. The Manager of Maintenance Standards committed to issuing the revision to 31MT-9RC06 prior to the start of the Unit 3 outage refueling (approximately March 1991). This item is closed.

2. (Open) Followup Item (528/90-20-04): "Inadvertent Shutdown Cooling Bypass" - Unit 1 (92701)

This item involved the discovery of bypass flow through valves SI-HV-690/691 when they are slowly jogged closed because they are not driven into their seat by the motor operator. The licensee initiated Engineering Evaluation Request 90-SI-093 which concluded that a plant modification would be required to fully address this problem. The EER is closed and engineering is pursuing a plant modification as long term corrective action. As an interim measure, the licensee has revised procedures 4XOP-XSI01, "Shutdown Cooling Initiation," to require operators to manually shut these valves to ensure that they are fully closed, eliminating any bypass flow. The inspector reviewed EER 90-SI-093 and noted strong recommendations which differed from the interim measures established prior to closure of the EER and that the EER discusses problems with manual operation of these valves in that it applies indeterminate torque to the valve stem. It also recognizes that "...both overthrust and underthrust are both of equal concern in terms of valve operability and reliability." The licensee is considering revising the interim measures. This item will remain open until these discrepancies are resolved.

3. <u>(Open) Enforcement Item 50-528/90-25-01: "Inoperable Emergency Lighting"</u>

In response to concerns regarding the application of quality assurance criteria to various aspects of the fire protection system, the licensee submitted a Justification for Continued Operation by letter dated July 20, 1990. In addition, the licensee responded to the Emergency Lighting Notice of Violation by letter dated November 15, 1990. These two documents contained several commitments for licensee action.

The licensee has identified 254 action items and entered all of these various commitments into the Commitment Action Tracking System. The tracking system tracks item status, responsibility, source, due date, and completion date. The licensee appears to be making acceptable progress in resolving these items. Only about four of the licensee's internal commitments were overdue; the licensee was aware of these and dealing with those items.

The licensee is tracking emergency lighting failures quarterly by means of a Component Failure Data Trending Report. The report is provided to the System Engineering Manager. Failures can be accessed in real time by System Engineers using networked computer terminals accessing the maintenance data base. The licensee plans to have a terminal in all System Engineer work spaces by about mid-year.

Emergency Lighting Unit No. 3EQDNF02 failed the 8 hour test in January, 1991, and has not been retested satisfactorily since. This unit is one of two redundant units for the Unit 3 control room. The inspector discussed the circumstances at length with licensee representatives and ascertained the following:

a. A nonconformance report was written to document the situation and provide a vehicle for resolution and corrective action.

b. A problem resolution sheet was written to initiate the necessary reviews to determine reportability. The licensee did not consider the situation reportable because the failed unit is backed-up by a redundant unit.

c. Licensee engineering evaluation was that the unit batteries need replacement. Because the licensee does not have sufficient spares on hand, new batteries were placed on order.

d. The licensee has readjusted the low voltage cut out on the two control room battery banks in each unit to

properly compensate for cable voltage drops. The inspector reviewed these calculations and found them acceptable.

The inspector considers that the licensee is dealing with the above failure in an acceptable manner.

The inspector discussed the licensee's actions to deal with emergency lighting failures. The licensee has taken action to see that future emergency lighting failures are documented using the nonconformance reporting system to assure that problems are dealt with in a timely manner with the benefit of engineering and management involvement.

The inspector discussed the EER backlog with licensee representatives and found that the EER backlog had only been reduced by about 10% and the average EER age was excessive. The licensee acknowledged the problem and was evaluating actions to effect better control of the EER backlog and age.

This item remains open pending further review of the overall issue by the inspector.

B. Unit 3

1. (Closed) Enforcement Item (530/90-20-01): "Atmospheric Dump Valve (ADV) Nitrogen Accumulator Found Isolated" - Unit 3 (92702)

This item involved an improper valve lineup performed by Unit 3 operators which isolated the ADV accumulator when the isolation valve should have been locked open in accordance with procedure 40AC-0ZZ06, "Locked Valve and Breaker Control." The operators involved were counselled, all operators were briefed on the importance of attention to detail, an investigation was conducted utilizing the Human Performance Evaluation System (HPES) program, and each shift received training on independent verification. The inspector reviewed the corrective action, had no further questions, and concluded that these actions appear appropriate to address this event. This item is closed.

C. Units 1, 2, and 3

1. (Open) 10 CFR Part 21 Report (89-18-P): "ABB Power Distribution, Inc. Current Transformer (CT) Encapsulate Material" - Units 1, 2, & 3 (92701)

This item involved a softening of the epoxy-anhydride encapsulate material in CTs due to high humidity conditions. The licensee has evaluated this in EER 89-XE-28 which refers to EER 89-NG-10. The inspector reviewed these two EERs and noted that the disposition does not clearly identify the licensee's action on this issue. This item will remain open pending additional information from the licensee.

2. <u>(Closed) 10 CFR Part 21 Report (89-24-P): "BW/IP International, Inc. High Pressure Swing Check Valve Failure" - Units 1, 2, & 3 (92701)</u>

This item involved the failure of a check valve at Comanche Peak Steam Electric Station. The licensee has evaluated the concern, determined that 69 affected valves exist in each unit, and concluded that only six valves per unit would be a safety concern if they failed to block flow and potentially cause an interfacing system loss of coolant accident (ISLOCA).

The first refueling outage after receipt of the associated Information Notice (90-03) occurred in Unit 2 and coincidentally included scheduled inspections of 17 affected valves under the ongoing Check Valve Preventive Maintenance Program. None of these valves had any defect indications. Additional affected valves will be inspected in future outages in accordance with the ongoing program.

The licensee is currently performing a fracture mechanics study which preliminarily suggests that a critical flaw size would have to be greater than 0.25 inches for all valves. The licensee is also performing a Probabilistic Risk Analysis (PRA) to quantify the contribution of these check valve failures to the probability of an ISLOCA. Qualitative analysis suggests that if the Commanche Peak and Palo Verde data is combined, the resulting contribution to ISLOCA appears to be acceptably low.

The licensee expects to finish the fracture mechanics and PRA study during the second quarter of 1991. The inspector concluded that these activities appear appropriate to address this issue. This item is closed.

3. <u>(Closed) 10 CFR Part 21 Report (89-25-P): "Deficiency With Limitorque SMB-000 and SMB-00 Motor Operator Torque Switches" - Units 1, 2, & 3 (92701)</u>

This item involved a deficiency with cam-type torque switches in that fiber spacers permit loosening of stationary contact screws. One consequence of this type of failure is the potential for affecting the torque which will break the torque switch current and stop the operator from delivering torque to the valve. The licensee issued EER 89-XE-059 on November 27, 1989. The EER is still open and the system engineer expects to close it during the next month. The system engineer noted that PCN 3

to procedure 32MT-9ZZ48, "Maintenance of Limitorque Motor Operators," issued on January 3, 1991, requires workers to inspect for fiber spacers and write a work request to replace any torque switch found with fiber spacers. The inspector considers the actions taken to have been slow, but technically adequate for this issue. This item is closed.

4. (Closed) 10 CFR Part 21 Report (89-28-P): "Cooper-Bessemer Emergency Diesel Generator (EDG) Crankcase Explosion" - Units 1, 2, & 3 (92701)

This item involved two crankcase explosions of diesel generators at the Susquehanna Steam Electric Station. Cooper-Bessemer has concluded that both of these explosions were due to casting defects which they consider to be "extremely rare." They therefore conclude "that there is no generic impact as a result of the reported incident" and that licensees with similar diesels need take no further action. The licensee has reviewed this event and had discussions with the Cooper-Bessemer owner's group and with Cooper-Bessemer. As a result, the licensee has initiated several actions which will limit the impact of what is believed to be contributing factors to this event. These actions include submitting a Technical Specification change request to move the 110% load test to the end of the 24 hour Surveillance Test run so the heavy load test can occur when the engine is fully warmed up. Additionally, the licensee has modified their monthly surveillance test procedures to run the diesels for four hours when practical rather than just one hour. In addition, Cooper-Bessemer has generated service bulletins which recommend loading and unloading profiles which the licensee is evaluating for inclusion in diesel testing and operating procedures. According to the system engineer, a final root cause of failure has not been fully agreed on by Cooper-Bessemer and the owner's group. The licensee is following testing and other actions being taken by Susquehanna and Cooper-Bessemer and has stated that as further lessons are learned from these events, they will receive service bulletins, owner's group comments, and if warranted, amended or additional 10 CFR Part 21 reports. The inspector concluded that the licensee appears to be taking appropriate action. This item is closed.

5. (Closed) 10 CFR Part 21 Report (89-31-P) and LER (528/89-18-L0/L1): "Henry Pratt Company Valve Failures" - Units 1, 2, & 3 (92701)

This item involved the intergranular cracking and failure of spiral pins used to attach the disk of butterfly valves to the stem. This issue was addressed in Inspection Report 528/529/530/89-49, paragraph 12. The inspector reviewed supplement 1 to the initial 10 CFR Part 21 Report and had no further questions. This item is closed.

3. Review of Plant Activities (71707 and 93702)

A. Unit 1

Unit 1 entered this reporting period operating at 100 percent power. On January 12, 1991, the unit was downpowered and the reactor manually tripped to commence a scheduled 39 day surveillance test outage. Major outage activities included performance of 18 month surveillance tests (Integrated Safeguards surveillance, Emergency Diesel Generator inspection, snubber inspections, Emergency Safeguards Features Battery surveillance and others), ASME Section XI pump and valve inspections, rewiring and testing of many motor operated valve operators, circuit breaker testing, implementation of some site modifications, and performance of many corrective maintenance work items. The outage was completed three days ahead of schedule, with Mode 4 and Mode 3 entered on February 13, 1991, Mode 2 and Mode 1 on February 16, and synchronization to the grid on February 16. Power ascension was in progress at the end of the reporting period.

B. Unit 2

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

C. Unit 3

Unit 3 operated at essentially 100 percent power throughout this 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
- 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. <u>Monitoring Instrumentation</u> - Process instruments were observed for correlation between channels and for conformance with Technical Specifications requirements.

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

4. <u>Equipment Lineups</u> - 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. <u>Equipment Tagging</u> - 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. <u>General Plant Equipment Conditions</u> - 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. <u>Fire Protection</u> - Fire fighting equipment and controls were observed for conformance with Technical Specifications and administrative procedures.

   The inspector asked a stationary fire watch in the Unit 1 ESF Switchgear Room about the assigned duties. The fire watch did not know of the requirement to telephone the control room to advise them to secure ventilation as specified in the Compensatory Measures section of the Fire System Impairment Log Sheet for this fire watch. The impaired fire protection equipment were dampers which may not fully close against the possible differential pressures in the ventilation duct. The inspector was told that the fire watch had never read this section of the Fire System Impairment Log. The inspector identified that there was not consistent guidance on the appropriate steps in dealing with an actual fire between the fire watch procedures and training, and the fire department personnel.

   The inspector later questioned a roving fire watch in the Unit 1 "A" Train Auxiliary Feed Pump Room about the assigned duties. While documents existed which showed appropriate fire watches were conducted, the fire watch had problems identifying the impairments which were to be compensated and when the impairments were identified from a computer printout, the fire watch did not know the locations of the impairments. The inspector further identified that the two impairments which were identified by the fire watch to be checked were for Unit 1, and not Unit 3 in which the fire watch was located. It was later

identified by the licensee that Unit 3 fire watches had the wrong printouts. It appeared to the inspector that the computer printouts were not essential to conduct the fire watches.

The inspector concluded that the fire watches lacked complete understanding of their responsibilities, and in the case of the stationary fire watch, had inadequate direction regarding these responsibilities. The licensee agreed with these observations and committed to revising the fire watch program to provide unambiguous directions to the fire watches. The licensee also plans to review the use of computer printouts of fire protection equipment impairments. The licensee committed to either stop providing these lists to the fire watches and justify this position, or provide the fire watches enough training to use these lists.

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.

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

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

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

Unit 1

- "A" Emergency Diesel Generator
- Boration Flowpaths

Unit 3

- Auxiliary Feedwater "A" and "B"

No violations of NRC requirements or deviations were identified.

5. Surveillance Observations - 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
° 73ST-1DG01	Class 1E Diesel Generator and Integrated Safeguards Surveillance Test Train "A" (Loss of Power Test)
° 73ST-1CL01	Local Leak Rate Testing
° 36ST-9SB09	Plant Protection System Resistance Temperature Detector Time Response Test (T112HA)

Unit 3

° 36ST-3SE06	Log Power Functional Test
° 36ST-3SB19	CPC Input Loop Calibration for Channel "D"

No violations of NRC requirements or deviations were identified.

6. Plant Maintenance Observations- 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

- Calibration of new positioner on ADV 1SGB-HV-178
- Troubleshooting the "A" EDG normal shutdown sequence failure
- Open and inspect SGN-V109 3-inch check valve

Unit 2

Description

- H2 tank filling

Unit 3

Description

- QSPDS Broken Wire Repair
- QDN-F02 8-hour burn test

7. Reactor Coolant System (RCS) Cooldown Rate Limit Exceeded - Unit 1 (92700 and 93702)

At about 12:15 PM (MST) on February 10, 1991, while the Unit was in Mode 5 and RCS temperature was approximately 190 degrees F, operator actions to eliminate a slight heatup resulted in inadvertently exceeding the RCS cooldown rate Technical Specification (TS) limits. Shortly before the heatup was noted, operators had throttled the Shutdown Cooling (SDC) heat exchanger (HX) flow control valve, 1SIA-HV-657, in the closed direction, and thought that this was the cause of the observed heatup. However, operators had also secured the Wet Layup Cleanup (WLCU) system for the Number 2 Steam Generator (SG2) at about the same time.

Control of SDC flow through the HX was complicated because valve 1SIA-HV-657 apparently stuck in its position, which was estimated to be about 10 percent open. This condition has occurred previously and was attributed to the valve operator being undersized for the high differential pressure across this valve when the valve is nearly closed. Procedure 41OP-1SI01, "Shutdown Cooling Initiation," Step 4.3.6, provides instructions to regain control of 1SIA-HV-657. The procedure directs the operator to reduce the differential pressure by throttling the Low Pressure Safety Injection (LPSI) Header A to Reactor Coolant Loop 1A and 1B valves, 1SIA-UV-635 and 1SIA-UV-645, while opening 1SIA-HV-306, the LPSI-SDC HX "A" Bypass valve, to maintain the required SDC flow rate. The operators attempted this, but apparently did not reduce the differential pressure enough to free 1SIA-HV-657, which they attempted to periodically jog in the open direction. Operators used the control board Valve Position Indication (VPI), in conjunction with the SDC flow indication and the SDC injection temperature indication (TE-351Y), to confirm that the valve was not moving. However, the

VPI indicated that 1SIA-HV-657 was about 60 percent open, and the valve position was not observed locally. The VPI was later determined not to be functioning properly.

Operators then attempted other methods of reducing differential pressure, not described in the procedure. First, they fully opened 1SIA-UV-635 and 1SIA-UV-645, then opened 1SIA-HV-306 to obtain about 5,000 gpm, which is the procedural upper flow limit for the LPSI pump. The control valve still would not open following this action. The operators then returned the flow rate to the normal band (4,000 - 4,500 gpm) by jogging closed 1SIA-HV-306.

Finally, after some discussion among the operators, they decided to close 1SIA-HV-686, the "A" SDC HX outlet valve, which is upstream of 1SIA-HV-657. About one minute after 1SIA-HV-686 began to close the operator regained control of 1SIA-HV-657, based on the VPI indicating the valve moved from 60 percent to 75 percent open. A minute later, with 1SIA-HV-686 still indicating partially open, the operator repositioned its handswitch momentarily to "OPEN," resulting in the valve fully opening. The operators simultaneously jogged 1SIA-HV-306 closed to maintain the total flow rate in the normal band, and since 1SIA-HV-657 was now open much further than before, the flow rate through the SDC HX was much greater.

While 1SIA-HV-686 was still mostly closed, the water in the SDC HX was significantly cooled. When the flow path through the SDC HX was re-established at the higher flow rate, the cooled water passed rapidly through the SDC loop and into the RCS, resulting in a large temperature decrease over a short period of time. The SDC loop injection temperature is sensed by temperature element TE-351Y, which is the instrument procedures indicate is to be used for compliance with procedural and regulatory requirements. TE-351Y showed a temperature decrease from about 193 degrees F to 100 degrees F in about 2.4 minutes, or at a rate of about 2325 degrees F/hr. Bulk RCS temperature also dropped, with Loop 1B cold leg temperature going from 190 degrees F to 150 degrees F in 6.0 minutes. Pressurizer level decreased from 67 percent to 60 percent in 12 minutes, indicating a bulk RCS cooldown rate of 155 degrees F/hr. RCS bulk temperature stabilized at approximately 150 degrees F in about 20-25 minutes.

The TS cooldown rate limits are specified in Technical Specifications 3.4.8.1 is 100 degrees F/hr when temperature is above 148 degrees F, 20 degrees F/hr down to 115 degrees F, and 10 degrees/hr down to 94 degrees F. Operators were uncertain if the TS cooldown rate limits had been exceeded, and raised the question to the System Engineer, who determined that they had been exceeded. When this was determined, on February 11, 1991, the TS Action Statement was entered and the required engineering analysis of the effects of the cooldown were commenced. The inspector reviewed this evaluation, which was documented in Engineering Evaluation Request (EER) 91-RC-17. The EER concluded that there was no impact on the RCS components from a structural fatigue analysis standpoint or from a gross deformation analysis standpoint, there was no impact on the

SDC HX from a structural fatigue analysis standpoint, and that there was no impact on the reactor vessel belt line region from a crack propagation/brittle fracture standpoint. The EER further concludes that the transient was bounded by the existing analysis of the design.

The inspector noted that the Control Room Log contained no entries regarding this event or actions taken during the event. Additionally, the Unit Log for February 10, 1991, included only a statement that a Problem Resolution Sheet (PRS) was initiated because of problems controlling RCS temperature.

The inspector also noted that a Night Order was issued on February 10, 1991, to clarify management expectations for actions to be taken when 1SIA-HV-657 sticks. These expectations are consistent with existing procedures, but provide further clarification of how much valve motion may be necessary to reduce the differential pressure. Additionally, the Night Order states that an Auxiliary Operator should be available in the Auxiliary Building to respond to the situation, but was not definitive as to the response required. The Night Order also states that the standby train of SDC should be placed in service when RCS temperature rises to 190 degrees F while difficulties in controlling temperature are being experienced.

The inspector noted that the standby train of SDC could have been placed in service within about five minutes, and that the heatup rate (about 7 degrees F per hour) would not have resulted in exceeding any administrative temperature limits for over two hours. The Shift Supervisor had instructed the operators to place the "B" SDC train in service if temperature exceeded 200 degrees F.

The inspector was also informed that 1SIA-HV-686 had been momentarily shut on February 9, 1991, in a previous successful attempt to regain control of 1SIA-HV-687. In that instance a significant transient did not result. However, operators did not initiate action to address procedural deficiencies even though actions beyond the scope of existing procedures were apparently required.

Incident Investigation Report (IIR) 3-1-91-022 was initiated to evaluate the events associated with this transient, including procedural adequacy, equipment performance and personnel performance. This item will remain open pending the inspector's review of the IIR (Followup Item 50-528/91-01-01).

8. <u>Apparent Reactor Coolant System (RCS) Stratification in Loop 1 Hot Leg - Unit 1 (71707 and 92700)</u>

As a result of an NRC identified inconsistency between RCS Loop 1 Hot Leg Temperature (THOT) indications, the licensee has determined that stratification is apparently occurring in that hot leg.

On February 17, 1991, with the reactor at approximately 80 percent power, the NRC inspector observed that the Core Protection

Calculator (CPC) Channel "A" RCS THOT indication (T112HA) was reading about 5 degrees F lower than any of the other CPC channels. The sensor, a Resistance Temperature Detector (RTD), had been replaced during the Unit 1 Surveillance Testing outage just completed because a similar discrepancy had been identified by Systems Engineering as a result of trending. The inspector asked if the temperature difference was within acceptable limits. The Reactor Engineer (RE) determined that it was not acceptable, based on Engineering Evaluation Request (EER) 91-RX-006, which had been completed on February 13, 1991, to determine the amount by which a CPC RTD must deviate from the other RTDs to be declared inoperable. Consequently, CPC "A" was declared inoperable.

The licensee has determined that the RTD recently removed from the T112HA instrument loop was not out of calibration, based on both elements of the dual-element RTD reading within 0.2 degrees F. This provides additional evidence that the actual temperature is not the same at the different RTD locations. The four RTDs used as Loop 1 hotleg temperature inputs to the four CPC channels are located in the same planar cross-section, but are 90 degrees apart from each other.

The licensee has added a 5 percent penalty to the CPC Addressable Constant Control Element Assembly Calculator (CEAC) Penalty Factor multiplier, PFMLT to provide margin for the dropped 12-finger CEA event in some conditions. This change was conservative in that a 5 percent margin already was implemented. However, this temperature deviation could consume all that margin and allows for no other uncertainties.

While the licensee and vendor have determined that temperature stratification is apparently occurring in the Loop 1 hot leg, further analysis is ongoing. The inspector forwarded the results of this analysis, documented in Material Nonconformance Report 91-SB-1001, to NRR for technical review (Followup Item 50-528/91-01-02).

No violations of NRC requirements or deviations were identified.

9. Incorrect Lube Oil Added to Auxiliary Feedwater Pump and Boric Acid Makeup Pump - Unit 2 (71707)

During a routine control room observation the inspector noted that Problem Resolution Sheets 1812 and 1811 had been initiated to report the results of routine lube oil samples from the "B" train motor driven AFW pump and the "A" Boric Acid Makeup Pump. These results indicated that the incorrect oil had been added to these pump bearings. In the case of the AFW pump, the sample had been taken on 12/24/90 and the last documented oil change was 6/27/90. Engineering Evaluation Request 91-AF-02 documented an evaluation which concluded that the oil found in the AFW pump did not affect the operability or qualification of the pump. It also noted that a similar incident had been identified for a Safety Injection Pump, previously evaluated by MNCR 90-SI-021. Furthermore, the inspector

noted that NRC Inspection Report 528/90-23 paragraph 6 documented a case of incorrect lube oil added to a charging pump. Because of the apparently continuing problem with oil additions, the licensee initiated Incident Investigation Report 3-2-91-003 to assess the overall program for control of oils and lubricants. The inspector considers this action warranted and will review the IIR when complete (Followup Item 529/91-01-01).

No violations of NRC requirements or deviations were identified.

10. <u>Emergency Diesel Generator Air Start System Leakage - Unit 3 (61726 and 62703)</u>

The inspector performed walkthrough inspections of Unit 1 and Unit 3 Emergency Diesel Generator (EDG) buildings and the site maintenance shop. The repaired Unit 1 EDG inner cooler was observed in the maintenance shop awaiting reassembly and testing. The inspector noted that a significant amount of coating (appeared to be belzona) had been recently applied over portions of the inner cooler flanges and excess coating appeared to have been applied over portions of the inner cooler tube openings. The system engineer observed the condition concurrently and requested maintenance shop personnel to remove the excess material.

While no surveillance testing was observed in progress, the inspector reviewed records for the most recent testing of Unit 3 EDG air start receiver relief valves PSV-5, 6, 7 and 8 and inlet check valves V-066, -067, -068 and -069. Review of the applicable test records and procedures indicated that the testing had been satisfactorily accomplished.

During the inspection of the Unit 3 EDG building, the inspector noted an oily substance leaking from both of the EDG "A" air start receiver manway cover gaskets and, to a lesser extent, from both of the EDG "B" air start receiver manway cover gaskets. The inspector noted that work request tags (WR 396845 and WR 396847) on the EDG "A" air receivers had identified "oil bubbling from access covers." The air pressure of all in service receivers (one was being taken out of service for compressor maintenance) were being maintained by their corresponding compressors at 240 to 250 psig. The inspector discussed the noted condition with the system engineers, the Unit 3 operations supervisor, compliance and QA. The inspector inquired about the ability of the EDG air start system in Unit 3 to perform its design functions specified in UFSAR Section 9.5.6. Specifically, the inspector attempted to determine if a technical evaluation had been performed for the noted condition taking into consideration the following:

a) The air receivers were being maintained at their required pressure by a non-safety-related, non-seismic, non-class 1E powered compressor. The ability of the leaking air cylinders to maintain sufficient pressure to accomplish all its design functions without the assistance of the compressors was unknown. The amount of allowable leakage and the magnitude of

the identified leakage necessary to be able to make this determination, were unknown.

b) Evaluations were not performed to determine the substance leaking from the air cylinder manway cover gaskets, the source of the substance, and the possible deleterious effects of the substance on any part of the air start system such that it would preclude it from performing its function.

The PVNGS Updated FSAR, Section 9.5.6.1, Design Bases, states in part that "the DGSS [diesel generator start system] shall provide a stored compressed air supply sufficient for accomplishing diesel generator cranking cycle 5 times without starting the diesel generator air compressors," and "the DGSS shall remain functional during and after an SSE."

The inspector discussed the above noted observations and was informed of the following by the system engineers, the operations supervisor, QA, and compliance:

A. WRs 396845 and 396847 were written in May 1990 and were cancelled by work planning in October 1990 because inspection and cleaning of air receiver internals were scheduled for January 14, 1991 and February 17, 1991 by W.O.s 458522 and 458523. The W.O.s were subsequently rescheduled for performance in February 1991.

Since WRs 396845 and 396847 had been cancelled, the record for those work requests were no longer available and the only records available relating to the work request was the SIMS computer annotation that it had been cancelled and included in W.O.s 45822 and 45823 and the WR tags that had been inadvertently left hanging on the two EDG "A" air receiver manway cover gaskets.

B. The air receivers are not periodically tested and the leak rate from the manway cover gaskets had not been determined for the conditions identified by WRs 396845 and 396847. The existing leak rate, at the time of the NRC inspection, was unknown.

C. The system engineers and the operations supervisor considered the leaking air receivers to be operable. They were unable to state what the manway cover gaskets leak rates were nor how much leakage was acceptable for the receivers to be still capable of performing its design functions. The engineers and supervisors claimed that the leakage was acceptable as long as the low receiver air pressure alarm in the control room had not activated.

D. There was no indication that any monitoring of the leakage was being performed to assure that the leaking manway cover gasket was not deteriorating and the leakage had not increased since the condition was identified eight months earlier. The inspector recognized that control room operators would become aware of low pressure in the receivers when the low pressure alarm was annunciated. However, the inspector also recognized that as long as the compressors were available and the leak rate did not exceed the capacity of the compressors, the alarm would not activate and a deteriorating condition would not be evident.

E. The system engineers felt that the leaking substance was oil, was coming from the compressors, and did not feel that the oil had any deleterious effects on any part of the air start system.

F. No MNCRs regarding the condition were issued. The QC manager indicated that the condition appeared to be normal wear and tear and as such did not require an MNCR, as allowed by the MNCR procedure.

10 CFR Part 50, Appendix B, Criterion XVI, requires that measures be established to assure that conditions adverse to quality such as deficiencies and malfunctions be promptly identified and corrected. The noted air receiver manway cover gaskets leakage were not corrected for approximately eight months, the amount of leakage for the receivers to still be capable of performing its specified functions had not been determined, and the actual leak rate of the manway cover gaskets had not been determined. This appears to be a violation of 10 CFR Part 50, Appendix B, Criterion XVI. (Enforcement Item 50-530/90-01-02).

11. <u>Violation of Surveillance Requirement To Perform Emergency Diesel Generator (EDG) Inspections During Plant Shutdown - Unit 3 (62703)</u>

During this inspection period the inspector noted that recent Unit 3 EDG inspections recommended by the manufacturer were performed to meet Technical Specification Surveillance Requirement (SR) 4.8.1.1.2.d.1, but were not performed during unit shutdown conditions as required by the SR. This is an apparent violation of the SR (Enforcement Item 530/91-01-01).

The licensee performed some inspections with the unit operating because the required 18-month surveillance intervals would have expired prior to the next refueling outage in March 1991. In addition, with the manufacturer's concurrence, the licensee waived several of the required mechanical inspections until the refueling outage, as justified in Engineering Evaluation Request 90-DG-07. The SR allows the EDG manufacturer to specify the required inspections.

The SR specifies to perform the manufacturer's recommended inspections "at least once per 18 months during shutdown." The licensee meets this requirement by implementing two Surveillance Test (ST) procedures, 31ST-9DG01 (for the mechanical inspections) and 32ST-9PE01 (for the electrical generator inspections). In addition, the manufacturer's recommended 18-month instrumentation calibrations and air filter replacements are performed by preventive

maintenance tasks.

The inspector also noted that among the manufacturer's recommended "annual" inspections is a task to perform diesel generator instrument calibrations. These calibrations are covered by the licensee's PM program. However, the PM program specified a refueling outage frequency for these calibrations. This is inconsistent with the manufacturer's recommended "annual" inspection interval (allowed by the manufacturer to be 12 to 18 months), especially when prolonged outages extend the operating cycle. The licensee should determine the required frequency for the instrument calibrations and appropriately reflect the frequency in the scheduling system.

The licensee acknowledged the inspector's findings at the exit meeting and stated that they had determined that performance of EDG inspections for SR 4.8.1.1.2.d.1 with the unit operating at power was a reportable event per 10 CFR 50.73. In addition, the licensee committed to the following:

1) A review of this and other Technical Specifications surveillance requirements which require specified plant conditions to ensure they are being properly scheduled and performed in accordance with these requirements.

2) A review of the scheduling of EDG instrumentation calibration PM tasks to ensure manufacturer's recommended intervals are met.

3) A review of all PM tasks being used to meet surveillance requirements to ensure that the required tests and verifications are scheduled and performed within specified surveillance intervals.

The licensee stated that their review would be documented in Incident Investigation Report 3-1-91-017A.

One violation of NRC requirements was identified.

12. <u>Use of an Engineering Evaluation (EER) Request Not Formally Approved - Unit 3 (71707)</u>

On January 8, 1991, Unit 3 operations staff removed Spray Pond (SP) Train "B" from service to restore a temporary modification such that normal power cables for the spray and bypass valves could be re-terminated. Because the Essential Chillers (EC) use the SP system as a heat sink, operators also entered the Action Statement for EC train "B" inoperable (Technical Specifications 3.7.6). The Action Statement requires, in part, that within 1 hour normal HVAC is verified to provide space cooling to train "B" ESF rooms served by EC. Earlier the operators had questioned the ability of HVAC to provide acceptable cooling since the normal (nonessential) chilled water loop in the associated Air Handling Unit (AHU) had recently frozen and broken, and was then isolated. Operations, including an Operations Supervisor, were aware that an Engineering Evaluation Request (EER) was being written to determine whether the broken cooling coils would impact the ability to meet Technical Specifications requirements. Based on a verbal discussion with the final engineering reviewer/approver, and prior to his final review and signature, operations proceeded to remove the SP and EC trains from service to complete the maintenance. Subsequently, the EER was approved as written and specified certain temperature limits, outside of which would be required routine temperature monitoring of affected ESF equipment rooms.

The inspector questioned the decision making process which used an EER which had not been formally approved for the following reasons.

1) The maintenance was planned, but was discretionary. There was no apparent or compelling reason why the train outage could not wait for the final EER disposition.

2) Engineering was aware that the unapproved EER was being used for the operations decision. Although the inspector did not identify any weakness in the final disposition, in general such practice may result in pressure to complete the document as written, without further critical review.

3) The inspector noted that in NRC Inspection Report 529/90-46 paragraph 10 a review was made of an incorrect Night Order issued on the basis of a draft MNCR. The MNCR was later changed but the Night Order was not, causing initial confusion on the part of operations staff responsible for ensuring the provisions of the MNCR were met.

The inspector noted that management decision making based on incomplete or unapproved engineering documents is uncommon at PVNGS, but that it has caused confusion in the past and potentially could cause more serious problems. The specific case referred to here appears not to have created any problem, but if the practice becomes more prevalent it may lead to less than careful, thorough, and formal engineering inputs to the decision making process.

Licensee management acknowledged these comments and stated that their intent was to include all appropriate supporting group inputs to the management decision making process, and that such inputs be formal and complete when appropriate.

No violations of NRC requirements or deviations were identified.

13. <u>Potential for Small Break LOCA Due to Tube Rupture in the Reactor Coolant Pump Seal Cooler - Units 1, 2, and 3 (93702, 45000)</u>

During review of NRC Information Notice No. 89-54 "Potential Overpressurization of the Component Cooling Water System," APS identified a scenario in which a break in the reactor coolant pump High Pressure Seal Coolers (HPSC) could potentially result in a Reactor Coolant System (RCS) leak being released outside of the containment building. The scenario involves a leak from the reactor coolant pump HPSC into the lower pressure Nuclear Cooling water (NC) system. The resulting leak could potentially overpressurize the NC system. If this were to occur, and the NC containment isolation valves were unable to shut against the pressure or flow, and the operators were unable to identify the leaking seal cooler and isolate the leak with the seal cooler isolation valves, it could result in reactor coolant being discharged from the NC surge tank relief valve on the auxiliary building roof. APS performed an analysis of this scenario and determined that continued operation is justified. This justification was documented in a JCO sent to the NRC on January 18, 1991 (letter 161-03709-WFC/JST).

This JCO is being reviewed by the NRC (Followup Item 528/91-01-03).

No violations of NRC requirements or deviations were identified.

14. <u>Probablistic Risk Assessment - Units 1, 2, and 3 (71707)</u>

Pursuant to the requirements of NRC Generic Letter 88-20 to perform an Individual Plant Examination of the relative risks of plant transients and equipment malfunctions to the overall probabilistic risk of core damage, the licensee determined, preliminarily, that event sequences leading to a loss of the "A" 125 vdc Class 1E bus contributed over 80 percent of the total core damage frequency (CDF). The APS engineering group responsible for this probabilistic risk analysis (PRA) presented their preliminary results to licensee management in May 1990. Management was informed that conceptual engineering work was underway to determine the best design changes to mitigate the severity of these sequences. Although the preliminary overall CDF was only 0.001 per reactor year (one core damage event expected within 1000 years of operation), elimination of this event sequence was expected to reduce the CDF by nearly a factor of 10. However, in November 1990, the licensee Plant Modifications Committee (PMC) reviewed the Plant Change Requests which resulted from the conceptual engineering work and, although they were approved for detailed engineering design work in 1991, they were given a low priority. However, in February 1991 following a presentation of this event sequence to plant operations staff, the priority was increased and engineering design work commenced immediately.

The inspector noted the reason for the large contribution to the CDF was primarily that loss of this DC bus caused closure of main steam and feedwater isolation valves and initial loss of control power for

two out of three auxiliary feedwater pumps. This leaves the only remotely controlled source of feedwater to be the "B" auxiliary feedwater pump, since all normal feed sources are isolated by the closure of the Feedwater isolation valves. While the probability of the "B" auxiliary feedwater pump being out of service is small, this potential could result in a total loss of all feedwater and is consequently a high CDF risk due to the sensitivity of the PVNGS design to total loss of feedwater with no primary power operated relief valves.

While the licensee proceeds with engineering design work on plant changes to mitigate this event sequence, the licensee has stated that current Emergency Operating Procedures will provide sufficient guidance for operators to take manual control of the failed motor driven auxiliary feedwater pump and the failed closed valves in its flowpath. The inspector noted that general guidance exists in the Functional Recovery Procedures for the condition of loss of all feedwater and consists primarily of instructions to gain manual control of available pumps and flowpaths. The abnormal operating procedure for loss of DC bus "A" assumes the "B" auxiliary feedwater pump remains available and therefore gives no guidance for manual restoration of unavailable auxiliary feedwater. The licensee is evaluating further procedural and maintenance policy changes as compensatory measures until design changes are final. It is expected that these changes would reduce the risk of AFW unavailability should this event occur, as well as provide operators with better guidance recovering from the worst case scenario (i.e. loss of DC bus with loss of all feedwater).

No violations of NRC requirments or deviations were identified.

15. Plant Review Board Activities

During the inspection, the inspector questioned an observation that the Plant Review Board (PRB) had not reviewed a revised administrative procedure. Discussions with the licensee identified that the Technical Specifications for each unit had been amended such that PRB review of administrative procedures and changes was no longer required.

In addition, the inspector reviewed the procedure in question (01PR-DAP01; Administrative Controls Program). The inspector questioned the intent of a step regarding the issuance of letters, memoranda, and orders to provide management guidance on a temporary basis. The intent was discussed with licensee personnel. The inspector found that while the wording of step 3.7.6 was consistent with ANSI N18.7 (1976), the wording was not clear with regard to the limitations of use. The licensee agreed to evaluate the wording and revise, as necessary.

No violations of NRC requirements or deviations were identified.

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

The following LER was reviewed by the Resident Inspectors.

Unit 1

528/89-18-L0/L1 (Closed): "Henry Pratt Company Valve Failures" - Units 1, 2, and 3

This event is described and reviewed in paragraph 2.C.5 of this inspection report. Based on this review, this LER is closed.

17. Exit Meeting

The inspectors met with licensee management representatives periodically during the inspection and held an exit meeting on February 21, 1991. The licensee did not identify as proprietary any materials provided to or reviewed by the inspectors during the inspection.