

U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-528/92-10, 50-529/92-10, and 50-530/92-10

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

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

Inspection Conducted: March 1 through April 11, 1992

Approved By

Howard J. Wong  
H. Wong, Chief  
Reactor Projects Section 2

5/14/92  
Date Signed

Inspectors

D. Coe,	Senior Resident Inspector
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Inspection Summary:

Inspection on March 1 through April 11, 1992 (Report Numbers 50-528/92-10, 50-529/92-10, and 50-530/92-10)

Areas Inspected: Routine, onsite, regular and backshift inspection by the four resident inspectors, and three Region V inspectors. Areas inspected included:

- . review of plant activities - Units 1, 2, and 3
- . engineered safety feature system walkdowns - Units 2 and 3
- . surveillance testing - Units 2 and 3
- . plant maintenance - Units 1, 2, and 3
- . occupational exposure during outages - Unit 1
- . reactor trip and feedwater system water hammer event - Unit 2
- . simulator observation - Unit 3
- . restoration of time delay in core protection calculators (CPC) for reactor power cutback (RPCB) - Units 1, 2, and 3
- . licensed operator respirator qualifications lapse - Units 1, 2, and 3
- . followup on previously identified items - Units 1, 2, and 3
- . review of licensee event reports (LER) - Units 1, 2, and 3.



During this inspection the following Inspection Procedures were utilized: 30702, 40500, 41500, 60710, 61726, 62703, 71707, 62703, 83729, 92700, 92701, 92702, and 93702.

Results: Of the 11 areas inspected, one violation in Unit 1 was identified regarding radiation area posting (Paragraph 6.c).

General Conclusions and Specific Findings:

Significant Safety Matters: None

Violations: One cited violation - Unit 1

Deviations: None

Open Items: One new followup item was opened, four followup items were closed, and one followup item was left open.

Strengths Noted: A strength was noted on the licensee's development of a new technique for evaluating submersion skin doses due to Xenon-133. This technique appears to have several advantages over conventional methods.

Weaknesses Noted: A weakness was noted in the licensee's resolution of problems identified with a startup transformer disconnect. The failure to resolve the problem resulted in a reactor trip of Unit 2 (Paragraph 7.b).

## 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
*H. Bieling,	Manager, Emergency Planning
*T. Bradish,	Manager, Compliance
*J. Baxter,	Engineer, Compliance
*L. Clyde,	Manager, Operations Unit 3
E. Dotson,	Director, Engineering
*D. Elkinton,	Senior Quality Audits and Monitoring Specialist
*C. Emmett,	Senior Information Coordinator, Management Services
*R. Flood,	Plant Manager, Unit 2
*R. Fullmer,	Manager, Quality Audits and Monitoring
*D. Gouge,	General Manager, Operations Support
S. Guthrie,	Site Director, Quality Assurance (QA)
*W. Ide,	Plant Manager, Unit 1
*D. Johnson,	Supervisor, Compliance
J. Levine,	Vice President, Nuclear Power Production
*D. Mauldin,	Director, Site Maintenance & Modifications
*G. Overbeck,	Site Director, Technical Support (STS)
T. Shriver,	Assistant Plant Manager, Unit 2
R. Stevens,	Director, Nuclear Licensing & Compliance
*V. Vitale,	Supervisor, Security Operations

#### Site Representatives

*J. Draper,	Site Representative, Southern California Edison
*S. Gross,	Manager, El Paso Electric (EPE)
*R. Henry,	Site Representative, Salt River Project

\* Denotes personnel in attendance at the Exit meeting held with the NRC resident inspectors on April 15, 1992.

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

### 2. Review of Plant Activities - Units 1, 2, and 3 (40500, 71707, and 93702)

#### a. Unit 1

Unit 1 remained defueled during this inspection period.

#### b. Unit 2

The unit operated at 100 percent power until March 23, 1992, when a partial loss of power caused a reactor trip and feedwater hammer event as discussed in Paragraph 7. The unit started up on March 27, 1992, and returned to 100 percent power on March 29, 1992. On April

3, 1992, the "C" condensate pump tripped as discussed in paragraph 5, necessitating a power reduction to 93 percent power. The unit returned to 100 percent power that same day where it remained through the end of the inspection period.

c. Unit 3

Unit 3 operated at essentially 100 percent throughout this inspection period. A loss of the Core Operating Limit Supervisory System (COLSS) on March 17, 1992, forced a brief downpower to 99.7 percent.

On March 31, 1992, the "C" reactor trip breaker failed to trip open during the performance of surveillance procedure 36ST-9SB04. A special inspection occurred to review the specific details of this and other reactor trip breaker problems which have occurred at Palo Verde recently. These will be reported in Inspection Report 50-530/92-15.

d. Plant Tour

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

- o Auxiliary Building
- o Control Complex Building
- o Diesel Generator Building
- o Fuel Building
- o Main Steam Support Structure
- o Radwaste Building
- o Technical Support Center
- o Turbine Building
- o 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.

During a review of logs, the inspector noted that Unit 2 operators exited the technical specification action statement for a main steam trap isolation valve, which is a containment isolation valve, when the isolation valve was tagged shut. This position was taken since the valve was secured in the position to perform its safety function. Previously, the inspector had noted that Unit 3 operators did not exit the action statement under the same conditions. In both cases the valve had been inoperable due to problems with the operating solenoid. The inspector discussed this difference in actions with the licensee. The licensee acknowledged the inconsistency and is reviewing the issue to determine the appropriate



actions. The inspector reviewed the applicable Technical Specifications and Procedure 420P-2SG01, "Main Steam," and determined that the actions required when a steam trap is isolated (e.g., manually blow down the steam traps) are required by the procedure and are independent of the technical specification. The Technical Specification action statement requires only that the valve be shut in its safety position, if it is inoperable, and can remain so indefinitely. However, the surveillance requirements state that main steam trap isolation valves are considered operable when secured in their shut position. The inspector concluded that the administrative inconsistency did not result in any apparent safety significant consequences and that both units had complied with the TS requirements.

- (2) Monitoring Instrumentation - Process instruments were observed for correlation between channels and for conformance with Technical Specification requirements.
- (3) Shift Staffing - Control room and shift staffing were observed for conformance with 10 CFR Part 50.54.(k), Technical Specifications, and administrative procedures.
- (4) Equipment Lineups - Various valves and electrical breakers were verified to be in the position or condition required by technical specifications and administrative procedures for the applicable plant mode.
- (5) Equipment Tagging - Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment was in the condition specified.
- (6) General Plant Equipment Conditions - Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that could prevent the systems from fulfilling their functional requirements.
- (7) Fire Protection - Fire fighting equipment and controls were observed for conformance with technical specifications and administrative procedures.
- (8) Plant Chemistry - Chemical analysis results were reviewed for conformance with technical specifications and administrative control procedures.
- (9) Security - Activities observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures included vehicle and personnel access, and protected and vital area integrity.





- (10) Plant Housekeeping - Plant conditions and material/equipment storage were observed to determine the general state of cleanliness and housekeeping.
- (11) Radiation Protection Controls - Areas observed included control point operation, records of licensee's surveys within the radiological controlled areas, posting of radiation and high radiation areas, compliance with radiation exposure permits, personnel monitoring devices being properly worn, and personnel frisking practices.
- (12) Shift Turnover - Shift turnovers and special evolution briefings were observed for effectiveness and thoroughness.

e. Offsite Safety Review Committee (OSRC) Meeting

The inspector attended part of the scheduled all day meeting of the OSRC on April 1, 1992. The meeting addressed plant status, recent plant events, plans to expand OSRC staffing to a membership with significant radiological protection experience, recent Quality Assurance, Independent Safety Engineering Group, and Licensing activities, the new emergency operating procedures, and other current issues. The three external members, J. G. Keppler, J. D. Shiffer and Dr. Levy were present and contributed significantly to the discussions.

No violations of NRC requirements or deviations were identified.

3. Engineered Safety Feature (ESF) System Walkdowns - Units 2 and 3 (71710)

An engineered safety feature system was walked down by the inspector to confirm that the system was aligned in accordance with plant procedures.

Unit 2

o Auxiliary Feedwater

The Unit 2 Trains "A", "B", and "N" Auxiliary Feedwater (AFW) systems were walked down by the inspector to confirm that the system was aligned in accordance with plant procedures. No system alignment discrepancies or significant hardware problems were observed.

The inspector reviewed the licensee's method of meeting the Surveillance Test (ST) requirement of Technical Specifications 4.7.1.2, which states in part:

Each auxiliary feedwater pump shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by:

- 2. Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

The inspector noted that the licensee's procedures for meeting this requirement differed significantly from procedures written to meet similar TS requirements for emergency core cooling and other systems. The following procedures were reviewed:

- 40ST-9AF05, "Auxiliary Feedwater Monthly Alignment"
- 4XST-XAF01, "Auxiliary Feedwater Pump AFN-P01 Operability Test"
- 4XST-XAF02, "Auxiliary Feedwater Pump AFA-P01 Operability Test"
- 4XST-XAF03, "Auxiliary Feedwater Pump AFB-P01 Operability Test"
- 4XST-XSI07, "High Pressure Safety Injection System Alignment Verification"
- 4XST-XSI13, "Low Pressure Safety Injection System Alignment Verification"
- 4XST-XCH03, "Boron Injection Flowpaths--Operating"

The inspector noted that the AFW procedures did not require periodic position verifications of power-operated valves in the applicable flow paths, whereas procedures for the other applicable systems did require such verifications. In response to the inspector's questions, the licensee stated that the onsite Quality Assurance (QA) group had already identified this matter, and that Condition Report/Disposition Request (CRDR) 92-0191 had been written on March 27, 1992, to resolve the issue.

On April 13, 1992, the inspector reviewed the status of CRDR 92-0191, and noted that both plant management and the licensee's compliance group had concluded that the power-operated AFW valves in question were not required to be included as part of a documented 31-day surveillance requirement. As a basis for this conclusion, the evaluation response stated that the TS requirement was unclear in defining the "correct" position of the valves, since they were required to be closed during normal operation, and required to automatically open upon receipt of an actuation signal. These valves have valve position indicated in the control room, although valve position is not routinely documented.

At the close of the inspection period, QA had not reached a conclusion on the CRDR disposition. The inspector noted from discussions with NRR staff that NRC positions in past similar circumstances have required normally shut automatic valves to be included in this surveillance requirement. At the exit interview, the inspector stated that this item would be an open item pending the licensee's final resolution (50-529/92-10-01).

The inspector noted, in addition, the following discrepancies in Procedure 4XST-XAF02, dated January 22, 1992:

- a. Under "Objectives," the procedure states that this procedure ensures that each valve is in its correct position, and mentions TS 4.7.1.2.a.2 (quoted above). The verification valve lineup, however, is no longer included as part of the procedure.
- b. Under "Prerequisites," the procedure states:



Section 8.4, Monthly Valve Alignment Verification, shall be performed in Mode 3 during plant Startup, and during normal operation on a monthly basis.

However, the procedure has no Section 8.4, and the monthly valve alignment verification has been removed.

The licensee responded by noting that a Instruction Change Request had been initiated on March 17, 1992, to correct these discrepancies. The inspector concluded that although the licensee self-identified these discrepancies, the previous change to this procedure appeared to lack a thorough review.

### Unit 3

#### o Boration Flowpaths

No violations of NRC requirements or deviations were identified.

#### 4. Surveillance Testing - Units 2 and 3 (61726)

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.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

### Unit 2

<u>Procedure</u>	<u>Description</u>
36ST-9SB02,	"PPS Bistable Trip Functional Test"
74ST-9SI01,	"Safety Injection Tank Boron"
42ST-2ZZ23,	"CEA Position Data Log"

### Unit 3

<u>Procedure</u>	<u>Description</u>
77ST-3SB07,	"CPC 'A' Functional Test"
72ST-9RX02,	"Moderator Temperature Coefficient at Power"

No violations of NRC requirements or deviations were identified.



5. Plant Maintenance - Units 1, 2, and 3 (60710 and 62703)

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 department 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.

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

Unit 1

- o Refuel Machine Motor Repair
- o CEDM No. 86 Motor Replacement
- o Fuel Reconstitution

Unit 2

- o SI-244 Packing Adjustment

On April 3, 1992, during the performance of a nonsafety-related preventive maintenance (PM) calibration task, the Instrument and Controls (I&C) technician lifted a lead on the "C" condensate pump mini-flow recirculation flow transmitter which tripped the pump. The sudden reduction in condensate flow lowered feedwater suction pressure to the point where operators had to rapidly reduce power to 93 percent to prevent an automatic trip of a main feedwater pump. The inspector noted that the work order was written assuming the plant would be in Mode 5 or 6, the work order contained a statement that the instrument loop had a control function to trip the condensate on low flow, the work was approved for work on March 28, 1992 when the unit was in Mode 2, and the work was performed on April 3, 1992, when the unit was in Mode 1 at 100 percent power. The licensee responded to the event by initiating Condition Report/Disposition Request (CRDR) 2-2-0132 to address personnel performance and programmatic issues. The inspector concluded that appropriate precautions were not taken to prevent a plant transient when this Mode 5/6 work order was used during Mode 1 conditions, and encouraged the licensee to evaluate this event broadly enough to prevent recurrence. The licensee agreed with the inspector's comments and stated that the CRDR will address the programmatic issues.

Unit 3

- o Troubleshoot "A" and "C" Reactor Trip Switchgear Breakers



### Circuit Breaker Overhaul

The inspector reviewed a licensee procedure for overhauling General Electric medium voltage circuit breakers, procedure 32MT-9ZZ38, Revision 1, dated October 5, 1991, "Overhaul of AM-4.16-250-9H G. E. Magne-Blast Circuit Breakers." These breakers supply power to Class 1E loads. The inspector also reviewed the lesson plan for overhauling this type of circuit breaker. The training was contained in Lesson NEC28-02-XC-001-000, dated July 7, 1991, "Magne-Blast Circuit Breaker Overhaul."

The inspector found the lesson plan contained detailed criteria for overhaul of this specific type of circuit breaker. The inspector found that the overhaul procedure contained specific details on circuit breaker overhaul along with appropriate acceptance criteria. The procedure contained a number of technician verification signatures but did not contain any quality control witness points. Quality control was included through this procedure, however, by requiring a post maintenance test using Procedure 32MT-9ZZ34. Procedure 32MT-9ZZ34, Revision 3, dated October 5, 1991, "Maintenance of Medium Voltage Circuit Breakers AM-4.16-250-9H," which contained 21 quality control witness points. These quality control witness points were for critical circuit breaker characteristics.

The inspector reviewed the licensee's quality monitoring reports and found that quality assurance personnel had witnessed a number of General Electric Magne-Blast circuit breaker overhauls in 1991. These quality reports indicated that the procedures could be accomplished as written.

The inspector concluded that the level of detail contained in the Magne-Blast training lesson plan and overhaul procedures was adequate. The inspector concluded that the extent of quality oversight was adequate.

No violations of NRC requirements or deviations were identified.

### 6. Occupational Exposure During Outages - Unit 1 (83729)

The inspector examined this program area by review of Unit 1 radiation and contamination surveys, observation of work in progress, and discussions with cognizant personnel. In addition, the inspector conducted dose rate surveys in all three units using Geiger-Mueller tube survey instrument NRC Xetex 305B No. 8170, due for calibration April 17, 1992. Observations were made in the areas of control of radiological work, skin dose assessment, posting, and labeling.

#### a. Control of Radiological Work

During tours of Containment, the Auxiliary Building, the Fuel Handling Building, and the Radwaste Building, the inspector found that Radiation Protection Technicians (RPTs), in general, were aggressive in controlling exposure and ensuring worker adherence to sound radiological work practices. Contractor RPTs were appropriately prompt in referring questions to licensee RPTs and





supervisors. Workers questioned were well-briefed on expected radiological conditions and RP procedural hold points.

In addition, the inspector noted that personnel dosimetry devices and protective clothing, in general, were properly worn by workers. Monitoring instrumentation was in current calibration and periodically source checked. Workers were prompt and consistent in use of portal monitors, frisking equipment, and radiation monitoring instruments.

b. Skin Dose Assessment

The licensee had developed a new technique for evaluating submersion skin doses due to Xenon-133 (Xe-133). Conventional methods of assigning these doses rely on Marinelli gas sampling and calculational techniques, and demand generous conservatism due to inherent sampling errors, imprecise recording of worker stay times, and the difficulty of accurately measuring the low energy beta spectrum. The licensee's new technique was based on the observed correlation between the retention of Xe-133 in the body of the exposed individual and the calculated skin dose due to submersion in the gas cloud. Xe-133 retention was measured using conventional Whole Body Counting (WBC) techniques.

Since WBCs had been routinely conducted after containment entries into noble gas environments, the licensee had been able to compile a significant amount of data to statistically substantiate the observed correlations. In addition, the licensee had been thoroughly evaluating the technical validity of the new method, including consideration of Xe-133 intake paths (inhalation versus skin absorption), retention and removal mechanisms, and the effective Xe-133 half-life in the body with variable individual biological parameters (such as body fat content or breathing rate).

The inspector noted that the new technique, if properly developed and validated, might prove to have several advantages over conventional methods, including reduction of sampling and stay-time calculational errors. In addition, the new technique exhibited a relatively low limit of detection (0.1 millirad skin dose correlated to about 10 nanocuries of Xe-133). The inspector concluded that the licensee's efforts toward achieving technical excellence in this area were commendable.

c. Posting

On March 16, 1992, the inspector toured the Unit 1 radwaste storage yard. When entering the yard from the Auxiliary Building stairway door, the inspector noticed that the area was posted only as a "Radioactive Material Storage Area" (RMSA). The inspector performed dose-rate surveys in the area, and noted radiation levels of 20-30 millirem/hour.

10 CFR 20.202 defines a "radiation area" as any area accessible to personnel in which a major portion of the body could receive, in any one hour, a dose in excess of 5 millirem. 10 CFR 20.203 requires such an area to be conspicuously posted as a "Radiation Area."

The inspector noticed that additional radiological boundaries had been established on either side of the refueling water tank. When exiting and re-entering the area via these boundaries, the inspector noted that these entrances were posted both as an RMSA and as a "Radiation Area." The inspector then reconfirmed the posting at the yard entrance from the Auxiliary Building, and noted specifically that no "Radiation Area" posting was present at that entrance point.

The inspector informed Unit 1 RP representatives that the area was not properly posted as a "Radiation Area." An RPT was immediately sent to correct the posting, and to verify all other postings in the area.

The licensee's corrective actions to this finding included the following:

- (1) Walkdowns were performed in all three units to verify that similar required postings were present.
- (2) The Unit 1 RP manager (RPM) attempted to determine the cause of the missing posting. Investigation revealed that a survey of the area had been conducted earlier in the day, and that the RPT had specifically verified all postings. The RPT stated that a "Radiation Area" posting had been present at the yard entrance from the Auxiliary Building at the time of the survey. The licensee was unable to determine a reason for the missing posting.
- (3) The licensee reemphasized to all technicians involved the importance of verifying that postings were commensurate with survey results and NRC requirements.

In addition, the Unit 1 RPM discussed with the inspector extensive measures taken in mid-February to preclude improperly posted or non-posted radiological areas. The inspector performed extensive surveys of similar areas in all three units. No additional examples of improper posting were noted.

The inspector concluded that the failure noted above constituted a violation of 10 CFR 20.203 (50-528/92-10-02). Based on the licensee's prompt and extensive corrective action, no response to this violation will be required.

d. Labeling

During tours of the Unit 2 radwaste storage yard, the inspector noticed that culverts placed around low activity resin liners were



inconsistently labeled. Most culverts were labeled with on-contact and 18-inch radiation level measurements relating to both the culvert and the liner. The label on Culvert 13, however, only had information related to the liner; as a result, no label information was provided regarding actual dose rates to an individual standing in the vicinity of the culvert. The culvert was in a properly posted radiation area.

In addition, the inspector measured on-contact and 18-inch dose rates significantly different from the label information on two 55-gallon drums of radioactive sludge and wet boron waste stored in a high radiation area. As one example, one of the drums was labeled as having radiation levels of 138 millirem/hour on contact and 29 millirem/hour at 18 inches; the inspector's survey showed actual levels to be approximately 600 millirem/hour on contact and 140 millirem at 18 inches.

The inspector brought these deficiencies to the attention of the licensee. The licensee promptly resurveyed the items. Licensee survey readings were commensurate with those measured by the inspector. Culvert 13 was relabeled with dose information pertaining to both the liner and the culvert. The 55-gallon drums were relabeled to provide accurate dose information. The licensee stated that drum contents appeared to have settled following recent relocation of the drums. The inspector concluded that, with the exceptions noted, observed aspects of the licensee's RP program appeared adequate in controlling occupational exposure during outages. The licensee's aggressive efforts to develop a new technique for evaluation of skin dose due to Xe-133 was considered a program strength. One violation of NRC requirements was identified.

7. Reactor Trip and Feedwater System Water Hammer Event - Unit 2 (93702)

On March 23, 1992, at 9:53 a.m., the Unit 2 reactor tripped from 100 percent power due to a loss of power to a 13.8kv non-class bus supplying power to two out of four reactor coolant pumps. In addition, the Unit 2 "A" Train class 1E bus deenergized and the "A" Emergency Diesel Generator (EDG) started and energized the bus. The resultant momentary power loss to the Steam Bypass Control System (SBCS) prevented automatic SBCS valves from opening, and thus lifted several steam generator main steam safety valves (MSSVs). Operators utilized manually controlled atmospheric dump valves (ADVs) to lower main steam pressure and control decay heat removal. During and after the trip, portions of the main feed system experienced significant water hammer causing damage to six pipe supports or snubbers of the main feed pump suction piping. Immediately prior to the trip, operators had transferred 13.8kv non-class bus NAN-S01 from its normal auxiliary transformer supply to the alternate startup transformer supply. In this configuration fast-transfer capability was not available. Several seconds after the successful transfer, the startup transformer (NAN-X01) breakers opened thereby deenergizing bus NAN-S01 and causing the reactor trip. In addition, this startup transformer was also supplying normal power to one of the Unit 3 class 1E busses, which

caused the Unit 3 "B" EDG to start and energize the bus. The licensee determined that both EDGs started as designed. The inspectors' review of this event focused on the water hammer and startup transformer disconnect switch operation as described below:

a. Feedwater and Condensate System Water Hammer

As a result of the partial loss of non-class IE power (NAN S01), discussed above, main feedwater (FW) pump "B" and condensate pumps "A" and "B" tripped. FW pump "A" and condensate pump "C" remained running. The operators experienced difficulties maintaining Steam Generator (SG) 2 level, ultimately closing both the downcomer and economizer valves, feeding the steam generators with AFW pump "B" and manually tripping FW pump "A." System design provided for a mini flow bypass for the condensate pumps, to allow the pump to continue to operate with the discharge isolated. However, erratic operation of the flow control valve in the mini-flow bypass line resulted in erratic flow through the line and subsequent tripping of condensate pump "C" on low flow. Subsequent investigation by the licensee determined that the erratic flow control valve operation was caused by an incorrect high gain setting in the valve's controller.

Due to the loss of power, three second-stage reheat steam supply valves remained open, allowing hot condensate to collect in the heater drain tank. Heater drain tank pump "A" remained running and recirculated heater drain tank water, through a bypass line, back to the heater drain tank. However, when level increased in the heater drain tank, the normal level control valve opened, approximately 33 minutes after condensate pump "C" tripped, and heater drain tank hot water was pumped by the heater drain pump to the depressurized FW pump "A" suction and condensate pump "C" discharge piping resulting in water hammers. The licensee, with assistance from a consultant, subsequently evaluated these conditions and preliminarily determined that the water hammer resulted from heater drain pump injection of saturated high temperature water, with steam voids present in the water, into cooler feedwater piping, and pressure waves or pulses resulted from the collapsing and reformation of the voids as it propagated through the piping. The water hammer caused suction flow oscillations and vibration alarms on the tripped main feedwater pumps. Approximately ten minutes after the heater drain tank level control valve opened, operators secured the heater drain pump. Approximately ten minutes after the heater drain pump was secured the water hammers also stopped, as evidenced by the stopping of main FW pump vibration alarms.

Control Room (CR) operators noted that the condenser hotwell level was high out of the indicating range. Therefore, approximately twenty minutes after main FW pump vibration

alarms (water hammer indication) had stopped, CR operators decided to establish long path recirculation for feedwater system cooldown in accordance with Procedure 420P-2ZZ14, Revision 4, "Feed and Condensate System," and started the "B" condensate pump. The normal condensate system flow path through the demineralizers was isolated during the loss of power and subsequent recovery of power. An alternate flow path was provided via a bypass line around the demineralizers through bypass valve CD-195. The operators observed that the CD-195 valve position indication in the control room showed that CD-195 was open. However, the indication was in error because the position indicator was broken, and CD-195 was actually in the shut position.

Continuing with the attempt to establish long path recirculation, an auxiliary operator proceeded with opening the next to the last isolation valves before the condenser, SG 124 (Train A) and SG 125 (Train B). The procedure step for opening the last valve prior to the condenser, VA-31, followed the step to open SG-124 and SG-125 but was not required to be a sequenced step. When the operator opened SG 124, he reported local water hammer effects on the feedwater piping. Discussions with licensee personnel indicated that valve VA-31 may have been opened prior to opening SG-124 resulting in water hammer due to piping downstream of SG-124/125 being under condenser vacuum and dragging hot water into the line. Operators stopped valve line-ups until the piping stabilized and then continued. However, when feedwater cooldown did not appear to start, control room operators determined that CD-195 was actually still shut. A new valve lineup was re-performed to again establish long path recirculation. When the condensate pump discharge bypass valve was opened, a water hammer was again experienced in the condensate and feedwater piping caused by the refilling of the condensate and feedwater piping that had voids formed by prior valve manipulations.

The inspectors discussed with the licensee the post-trip sequence of events involving the use of Procedure 420P-2ZZ14, "Feedwater and Condensate," for establishing long-path secondary recirculation. The following items were noted:

- (1) Section 6 of the procedure is used to start a condensate pump. Section 7 is used to place the system in long-path recirculation from start-up conditions. Section 21 also places the system in long-path recirculation; however, Section 21 implements a recent plant modification specifically designed to prevent water hammer when initiating long-path recirculation with elevated feedwater temperatures.

As a pre-requisite to performing Section 21, a condensate pump must be running. Since no condensate pumps were





running when initially attempting to establish long-path recirculation, the operators first performed Section 6 of the procedure to start a condensate pump. Procedural statements at the end of Section 6 led the operators directly into Section 7. As a result, initial attempts to place the system in long-path recirculation were conducted using an inappropriate procedure (Section 7), employing a lesser level of operator controls to prevent system water hammer. As stated above, these efforts were complicated by the failure of the indication for CD-195.

- (2) In later attempts to reconstruct the sequence of events, the licensee was unable to locate the copy of 420P-2ZZ14 used to establish long-path recirculation. The inspectors noted that such procedures are normally retained, and are crucially helpful in understanding the control of operations exercised during plant events.

In response to the inspectors' observations, the licensee stated that applicable portions of 420P-2ZZ14 would be revised to ensure proper use of the system when establishing long-path recirculation.

The licensee performed walkdowns of the condensate and feedwater piping for the purpose of visually identifying any structural abnormalities that could have been caused by the waterhammer. Pump flanges were observed to be intact with no bolt elongation and no leaking. Included in the walkdown were 24 pipe supports (13 snubbers, 6 spring supports, and 5 rigid supports). Significant damage of four Pacific Scientific (PSA) "1/2" snubbers was observed. PSA 1/2 snubbers have a nominal capacity of 650 pounds. The four damaged snubbers were:

- North-South snubber at data point 16 (in proximity to FW Pump A suction nozzle)
- North-South snubber at data point 40 (located in long East-West pipe run upstream of FW Pump A suction nozzle)
- North-South snubber at data point 72 (similar to snubber at data point 40, but on long East-West pipe run upstream of FW Pump B suction nozzle)
- Axial North-South snubber at data point 67 (upstream of data point 72 about 15'6" West and 20'6" South of data point 72)

Based on the location of the pipe support damage and review of piping stress analyses, the licensee identified 16 areas to be susceptible to significantly increased stress as a result of the waterhammer. The 16 areas were subdivided into high and medium stress areas. All 16 areas were visually inspected.



Initially, the eight high stress areas were also inspected by magnetic particle testing. As a result of the magnetic particle test inspections, the licensee identified two welds per Train (four welds total) on branch connections to the suction piping for the FW pumps and one weld at a Train "A" suction piping elbow, which had rejectable linear indications. The licensee expanded the scope of the magnetic particle testing to include four of the medium stress areas. The licensee did not observe any defects in the medium stress areas.

All linear indications were ground until the defects were removed (verified by magnetic particle testing) and weld repaired, if required. A sample of one of the more significant linear indications was cut with the adjacent weld and base material, and was sent to a laboratory for sectioning and examination. The examination determined that the linear indication resulted from an incomplete weld. The repair of the other linear indications resulted in grind outs of approximately 9/32" depth. The pipe nominal wall thickness in these locations was 3/4". Subsequent licensee evaluation of the linear indications concluded that the indications were pre-existing defects and did not appear to have resulted from the water hammer.

The licensee replaced one of the four failed snubbers. The licensee performed piping analyses that demonstrated piping stresses, and support and nozzle loads to be within allowables without the other three failed snubbers; so the licensee removed the remaining three failed snubbers without replacing them.

Based on their preliminary evaluations, the licensee concluded that plant startup could proceed independent of ongoing studies by the licensee's engineering staff and outside consultants. However, the licensee implemented the following precautions as supplementary requirements for restart:

- The nine snubbers which showed no visual damage would be marked for position prior to startup and checked during heatup to verify thermal displacement (i.e., that the snubbers could still perform their functions to allow system thermal growth).
- Local vibration monitoring of FW pumps would be performed during startup.
- The system would be visually inspected as part of the walkdown to be performed during startup (visual inspections would include checking for flange and check valve leakage).

The licensee, and its consultant, were continuing with their evaluation of the water hammers experienced to further understand its mechanism, impact, and to determine if additional measures would be required to preclude similar occurrences. Correction of hardware deficiencies (condensate pump bypass valve erratic operation, broken position indicator for CD-195, etc.) were performed.

The inspector's review of licensee actions concluded that no safety-related portions of the SG or associated auxiliary feedwater piping had been affected by the water hammer, and that the licensee's actions to understand the event and its impact appeared thorough. The inspector's review of the licensee's modification of the long path recirculation procedure noted that there was still potential for entering the wrong section under hot, non-trip conditions with no condensate flow. The licensee stated that this weakness would be corrected and the inspector had no further questions.

b. Previously Identified Problems with Operation of Startup Disconnect on Transformer NAN-X01.

The inspector's noted that while hanging a clearance on February 4, 1992, problems had been noticed with opening the 13.8 KV NAN-X01 Z-winding disconnect, and a work request had been generated.

The inspectors reviewed the work request and clearance, and discussed disconnect operations with the auxiliary operator (AO) who had initiated the work request. The AO stated that, while operating the manual crank to open the disconnect, he had noticed a loud clanking noise. At the completion of crank travel, the disconnects had not reached their fully vertical (open) position. Since this represented an abnormal condition, the AO had initiated Work Request (WR) No. 815137 for electrical maintenance to troubleshoot the disconnect abnormality. The AO stated that an electrical foreman had come out to the switchyard, observed the disconnect problem, and concluded that the abnormality would not cause a problem while the disconnect was in its clearance position.

The inspectors discussed the subsequent closing of the disconnect with the AO who had performed the clearance restoration later on February 4, 1992. The AO stated that the disconnect had also operated abnormally on closing, as follows: while manually cranking in the shut direction, the disconnect had first moved in the open direction, past the vertical position, and then reversed direction toward the horizontal (shut) position. The AO stated that he noted this disconnect performance to be abnormal, but did not generate a work request, as he was aware that a work request had already been

generated earlier in the day to troubleshoot disconnect operation.

The AO stated that when the crank would turn no further, he had visually sighted the disconnect and all phases appeared to be making normal contact. The inspectors noted that the disconnect closure point is approximately 25 feet in the air and at a difficult angle for viewing from the ground. In response to the inspectors' question, the AO stated that no electrical maintenance personnel had been present to observe the disconnect closure. At the time of the reactor trip, no further action had been taken on the disconnect WR.

The inspectors noted that more thorough troubleshooting of disconnect operations might have detected the abnormal closure contact and prevented the condition which resulted in a reactor trip. In addition, the inspectors concluded that the lack of priority given the WR and the acceptance by operations of abnormal disconnect closure indications appears to represent a lack of sensitivity toward the reliability of offsite power sources. Although these power sources are not safety-related, they are intended to be reliable per General Design Criterion 17. The licensee acknowledged these observations and stated that disconnect operation procedures and operations training improvements would be included in the corrective actions.

In this event, three failures of nonsafety-related equipment were evident. The offsite electrical distribution and balance-of-plant equipment failures (startup transformer disconnect, condensate mini-flow control valve, and demineralizer bypass valve position indication) caused a reactor trip or subsequently contributed to significant water hammers in the feedwater and condensate systems. It appears that additional licensee management attention may be necessary to improve equipment performance in these areas to minimize plant challenges in the future.

No violations of NRC requirements or deviations were identified.

8. Simulator Observation - Unit 3 (41500)

The inspector observed one evaluated simulator session with Unit 3 operators. The evaluators included one unit representative, the Training Coordinator, who holds a Senior Reactor Operating license. There was no management presence during this session. The scenario was a large loss of coolant event with a loss of offsite power using the new, not yet implemented emergency operating procedures. The inspector noted generally appropriate use of the emergency operating procedures. Alarm response procedures were not always used by operators without prompting by the Shift Supervisor. Communications were not always formal and repeat backs were not always given, nor demanded. Command and control was positive. The evaluation discussions were candid and generally thorough. The inspector concluded that the evaluators properly

identified the inspector's observations and appropriately communicated the deficiencies to the evaluated crew.

The inspector noted one item that was not addressed by the crew nor the evaluators. Operators left keys in key lock switches, contrary to the 40AC-90P02, "Conduct of Shift Operations," procedure. The inspector concluded that this represents inattention to detail on the part of both the operators and the evaluators.

The inspector noted that this scenario began with the Shift Technical Advisor (STA) in the simulator control room. The inspector further noted that some simulator sessions begin with the STA out of the control room for up to ten minutes after the scenario begins. The inspector encouraged the licensee to continue the practice of delaying the STA's participation in simulator scenarios to accurately simulate the real situation.

No violations of NRC requirements or deviations were identified.

9. Restoration of Time Delay in Core Protection Calculators (CPC) for Reactor Power Cutback (RPCB) - Units 1, 2, and 3 (92700)

Based on the review of the Unit 3 reactor trip on November 14, 1991, discussed in Inspection Report 528/91-41, Paragraph 11, the licensee determined that the Control Element Assembly Calculator (CEAC) could perceive an RPCB due to a Control Element Assembly (CEA) group 4 subgroup slip, if the slip duration is less than 0.5 seconds. This results in the initiation of a designed delay in the CPC calculation which prevents a CPC-generated reactor trip for a short time (16 seconds in Units 1 and 3, and 20 seconds in Unit 2, since the delay is fuel cycle dependent). This delay is designed only to prevent an unnecessary CPC trip during a normal RPCB event and is not appropriate during slips of group 4 subgroups. As an interim resolution to this problem, the associated CPC and CEAC addressable constants were set to zero to nullify this delay. As a result of the interim resolution (setting the timer addressable constants to 0.0), the CPC and CEAC systems will cause a reactor trip in the event of a RPCB or group 4 subgroup slip.

The licensee performed a review of the reactor protection system and associated safety analysis and concluded that restoration of the time delay was appropriate for RPCBs caused by the loss of a Main Feedwater Pump (MFP), under certain conditions (RPCB system was in "manual select" Mode with sub-groups 4, 5, and 22 selected). The licensee stated that the analysis shows that all combinations of subgroup slips of valid RPCB groups (regulating groups 4 and 5, consist in subgroups 4, 5, and 20) of duration less than 0.5 seconds are less severe than the worst 4-fingered CEA drop already covered by the safety analyses. Based on this result, the licensee determined that sufficient margin is currently in the Core Operating Limits Supervisory System (COLSS) to offset the local power distortions caused by slips of these CEA subgroups such that immediate CPC action is not required. Following a January 31, 1991, conference call between the licensee and NRC (Region V and NRR) discussing the



licensee's evaluation, the time delay was restored for this condition. The licensee is continuing its evaluation of the RPCB for loss of load events prior to restoration of the time delay for that condition.

The inspector reviewed the licensee's analysis (Number SA-ALL-NCR-92-003-00). The analysis assumed that the RPCB system is disabled when one out of the two cutback banks is selected, thus ensuring a reactor trip and eliminating the scenario experienced in Unit 3, where one group drops as designed by the RPCB, and an un-selected RPCB subgroup then slips. The analysis also assumes that two consecutive slips of 25 inches each occur, which is based on the time required for a 150-inch drop. This is conservative because full velocity would not be actually achieved during the first 0.5 seconds of motion. The analysis considered various combinations of 4-fingered CEA subgroup and partial-subgroup drops for various initial conditions. The licensee determined that the distortion factor created by these drops was worse at 65 percent power (the minimum power for which RPCB is enabled) than at 102 percent power.

Consideration was given to the impact of COLSS and/or CEACs being in or out of service. Subgroup deviations less than 9.9 inches, which do not result in penalty factors being applied to the CPC calculations, were also addressed. The peak distortion factor calculated was 1.11. The Required Over Power Margin (ROPM) to be reserved by COLSS to protect against 4-finger rod drops is 115.2 percent (in Unit 3), which bounds the worst case double slip of any 4-finger subgroup combination, for which the ROPM is only 112.3 percent.

The inspector queried the licensee regarding how the ROPM is accounted for when COLSS is out of service, as this was not explicitly discussed in the analysis. The licensee response was that the ROPM is accounted for in the Technical Specification Limiting Conditions for Operation (LCO) related to COLSS being out of service, and that sufficient margin exists in this LCO.

The inspector concluded that the licensee's analysis was thorough and appeared to justify the reinstatement of the time delay for the conditions discussed above. The licensee reaffirmed its commitment to discuss with the NRC its evaluation for the loss of load RPCB event prior to restoration of the time delay for that condition.

No violations of NRC requirements or deviations were identified.

10. Licensed Operator Respirator Qualifications Lapse - Units 1, 2, and 3 (92700)

On March 6, 1992, the licensee determined that the respirator qualifications of approximately twelve of its licensed operators had lapsed since March 1, 1992, due to an administrative error. The lapses involved both training not being current and respirator physicals not being current, although not all individuals involved lacked both. The licensee confirmed that physicals required for maintaining operating licenses were not affected. Additionally, the licensee determined that



individuals who had been assigned as Fire Team Advisor during this time had been respirator-qualified. Control room staffing was also reviewed, by the licensee, and it was confirmed that the minimum shift complement on each shift during that period was satisfied with respirator-qualified personnel. The licensee initiated a Condition Report/Disposition Request (CRDR) to document its evaluation and its corrective actions.

The inspector concluded that the licensee's response was thorough and adequate.

No violations of NRC requirements or deviations were identified.

11. Followup on Previously Identified Items - Units 1, 2, and 3 (92702 and 92702)

a. Unit 1

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

This item involved the installation of pneumatic jumpers, which shut the fuel building supply dampers long enough for the exhaust fan to damage the fuel building roll-up door, thereby rendering the fuel building essential ventilation system inoperable. The licensee addressed Nuclear Engineering recommendations from Engineering Evaluation Request (EER) 90-AF-009 by supplementing the EER with Instruction Change Requests 24726 and 24725. The change requests incorporated additional lessons learned from this event. The EER further recommended a Plant Change Request (PCR) to install an interlock between the isolation dampers and the normal ventilation fans. The licensee later determined that this PCR was not cost effective and that the procedure changes being made were adequate to address the concerns. The inspector concurred with this determination and concluded that the procedure changes and the other corrective actions appeared appropriate to prevent recurrence. This item is closed.

(2) (Closed) Violation (528/90-20-02): "Post-Accident Sampling System (PASS) Over-Pressurization" - Unit 1 (92702)

This item involved the over-pressurization of the PASS system due to miscommunication leading to a valve misalignment. All the immediate corrective actions were complete. This item remained open pending an evaluation of all non-operations personnel who operated plant equipment. The licensee conducted evaluations and has implemented additional administrative controls to ensure that non-operations personnel who operate plant equipment adequately communicate with operators. The inspector identified additional groups who operate plant equipment beyond the licensee's evaluations and the



administrative controls for these groups have been evaluated to be appropriate. This item is closed.

b. Unit 2

(Open) Unresolved Item (529/91-35-04): "Scaffolding Deficiencies" - Unit 2 (92701)

This item involved scaffolding which did not meet the clearance requirements of the licensee's scaffolding program, and clearance was not addressed in the Engineering Evaluation Request (EER 91-ZJ-024) for that scaffold. The inspector noted two potential weaknesses. First, the scaffold program permitted scaffold which did not conform to the licensee's scaffold specification, 13-CN-380, to be erected prior to the completion of an EER documenting the evaluation. There was no maximum time period specified for the scaffold to exit without an evaluation. The second potential weakness was that the calculations did not consider the mass of material that could be placed on the scaffold. The licensee initiated Condition Report/Disposition Request (CRDR) 2-1-0131 to address these issues. The CRDR is now closed.

The first weakness is being addressed by Instruction Change Request (ICR) 23764 which will revise procedure 30DP-9WP11, "Scaffolding Instructions," to require a completed engineering evaluation prior to the erection of scaffolding which does not meet the criteria of scaffold specification 13-CN-380. This revision to 30DP-9WP11 is expected to be issued on or prior to May 1, 1992. The inspector noted that the licensee revised scaffolding specification 13-CN-380 to permit engineering judgment evaluations of scaffolding which do not meet the criteria of the specification without documentation other than an engineer's signature on the scaffold tag. CRDR 2-1-0131 identified the need for additional training of Civil Engineers who evaluate scaffolding. Since revision 2 to specification 13-CN-380 was issued on October 12, 1991, the licensee has been permitting engineering judgement evaluations of scaffolding which do not meet the criteria of the specification. The inspector questioned whether it was appropriate for engineers to perform engineering judgement evaluations without documentation when a training deficiency had been identified in this area. The licensee responded by limiting engineering judgement scaffold evaluations to only those engineers who, in the opinion of the Component and Specialty Engineering Supervisor, Civil, had adequate familiarity with specification 13-CN-380 and the calculation upon which it is based, 13-CC-ZZ-308.

The inspector noted that revision 2 to specification 13-CN-380 allows scaffold tie back (securing to) to any cable tray hanger provided that the unistrut is P1001 and meets other geometric requirements, while revision 1 to the specification permitted scaffold tie back bracing to only specified hangers in the control building on the 120, 140, and 160 foot elevations only and then only

if hangar specific criteria are met. The inspector further noted that page 8 of specification 13-CN-380 contains a table which permits modified bracing in certain locations including all elevations of the auxiliary building, where similar tables in calculation 13-CC-ZZ-308 required tie-backs. The inspector questioned the difference between revisions and whether calculation 13-CC-ZZ-308 bounds the tie back criteria and use of modified braces allowed in revision 2. The licensee indicated that further evaluation would be necessary.

The second weakness was addressed by an engineering evaluation which demonstrated that mass on a scaffolding increases damping, reduces vibrations, and increases the safety margins. The inspector noted that the scaffolding specification does not permit scaffolding to be supported by structures other than the floor or deck grating without an engineering evaluation. The inspector questioned the engineering evaluation of scaffolding including the mass that could be placed on the scaffold in the static support evaluation, particularly if the scaffold rests on another piece of equipment. The licensee indicated that the expectation of the Component and Specialty Engineering Supervisor, Civil, is that the engineering evaluation of this type of scaffolding is to be documented on an EER and is expected to include an evaluation of support capability, including the mass that can be placed on the scaffold structure. The licensee further indicated that this expectation is not documented but will be incorporated into the training being developed as a result of CRDR 2-1-0131.

The inspector noted two scaffold structures which were tied to safety-related cable tray hangars contrary to the criteria in revision 1 of specification 13-CN-380 and did not appear to be bounded by calculation 13-CC-ZZ-308. One was in the Unit 1 Control Building, 100 foot elevation in the Train "A" ESF switchgear room, scaffold tag number 31023. The second scaffold was in the Unit 3 Auxiliary Building, 120 foot elevation outside the Control Element Drive Mechanism Motor Generator room, scaffold tag 27108. The inspector concluded that further evaluation is needed to ensure that these scaffolds meet seismic requirements. This item will remain open pending resolution of these various issues which require further evaluation.

c. Unit 3

(Closed) Followup Item (530/91-19-03): "Westinghouse ARD Relay Failure" - Unit 3 (92701)

This item involved the failure of Westinghouse ARD 660-UR relays in service in safety related systems. Westinghouse issued a 10 CFR Part 21 report on this failure mode. The licensee conducted an extensive evaluation of the failures, the 10 CFR Part 21 report, and site history. A comprehensive testing program was developed to inspect all affected relays in the warehouse in accordance with the



recommendations in the 10 CFR Part 21 report, and all affected relays in the unit in accordance with a test methodology developed by APS. Westinghouse reviewed and concurred with the test methodology which involved a time response test of in service relays. None of the affected relays either in the warehouse or in service failed the testing criteria. APS developed a Vendor Corrective Action Report (VCAR) to evaluate Westinghouse's corrective action, manufacturing process, and future shipments. APS has also established a testing program for dedication of future acquisitions of affected relays. The inspector concluded that the licensee's actions appear appropriate. This item is closed.

No violations of NRC requirements or deviations were identified.

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

The following LERs were reviewed by the Resident Inspectors.

a. Units 1, 2, and 3

(Closed) LER 528:529:530/91-07-10/L1: "Technical Specification Bases Not Supported By Design" - Units 1, 2, and 3

This LER documents the licensee's August 22, 1991, determination that the Technical Specification (TS) bases were incorrect regarding the capability of the normal heating, ventilation, and air conditioning (HVAC) system to meet essential HVAC cooling loads in areas served by the Essential Chilled Water System (ECWS). The TS bases states that the normal HVAC system is redundant to the essential HVAC system, and that the allowed out-of-service time for the essential HVAC system is based in part on the availability of the normal HVAC system. However, the normal HVAC system's capacity is much less than that of the essential HVAC system, and is therefore not fully redundant. The licensee determined that the normal HVAC system adequately maintains the design conditions in the affected spaces during normal operating conditions, but not during Design Basis Accident conditions. Whenever the ECWS was inoperable for greater than 72 hours in Modes 1 through 3, the appropriate Technical Specification Action Statement (TSAS) for the affected Engineered Safety Features (ESF) pumps (e.g., be in at least Hot Standby within the next 6 hours) were not met. The licensee determined that this condition had occurred in each of the three units at least once since February 1990.

The licensee's immediate corrective actions included administratively imposing a 72 hour out-of-service time limit in place of the 7 day requirement of Technical Specification Action Statement (TSAS) "a" for Limiting Condition for Operation (LCO) 3.7.6 when only one train of ECWS is operable. Subsequently, the licensee evaluated the licensing and design bases and determined that the time constraints of TSAS 3.7.6.b, which addresses only one Train of ECWS being operable, are sufficient to preclude also



entering the TSASs for the equipment affected by the other ECWS Train being inoperable. The most limiting components are the vital bus inverters and the emergency battery chargers located in the DC equipment rooms. The licensee has submitted a licensing amendment to correct the TS bases and reduce the allowed out-of-service time in TSAS 3.7.6.a from 7 days to 72 hours.

The licensee determined that the error was the result of licensee and contractor personnel who reviewed the TS and TS bases for LCO 3.7.6 not recognizing that the normal HVAC system was not fully redundant to the essential HVAC system.

The error was determined to affect the licensing bases, but not the design basis, of the ECWS, and was consequently reported under 10 CFR 50.73, but not under 10 CFR 50.72.

The inspector concluded that the licensee's evaluation and corrective actions were adequate.

13. Exit Meeting - (30702)

An exit meeting was held on April 15, 1992, with licensee management and the Resident Inspectors during which the observations and conclusions in this report were generally discussed. The licensee did not identify as proprietary any materials provided to or reviewed by the inspectors during the inspection.



