U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-528/88-02, 50-529/88-02 and 50-530/88-02.

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

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

Licensee: Arizona Nuclear Power Project
P. O. Box 52034
Phoenix, AZ. 85072-2034

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

Inspection Conducted: January 17 through March 5, 1988.

Inspectors:	[signature] for T. Polich, Senior Resident Inspector	4-1-88 Date Signed
	[signature] for J. Ball, Resident Inspector	4-1-88 Date Signed
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	James F. Melfi J. Melfi, Reactor Inspector	4/1/88 Date Signed
Approved By:	[signature] for S. Richards, Chief, Engineering Section	4-1-88 Date Signed

Summary:

Inspection on January 17 through March 5, 1988 (Report Numbers 50-528/88-02, 50-529/88-02 and 50-530/88-02).

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors and one region based inspector. Areas inspected included: previously identified items; review of plant activities, plant tours; housekeeping; engineered safety feature system walkdowns; surveillance testing; plant maintenance; inoperable control element assembly; inoperable high pressure safety injection pumps during mode 4; essential cooling pump room alarms; control room annunciators; operational errors; fuel receipt and storage; preparation for refueling; review of licensee programs for followup of NRC information notices and bulletins; NRC compliance bulletin number 87-02, fastener testing to determine conformance with applicable material specifications; followup of licensee event reports; and review of periodic and special reports.

During this inspection the following Inspection Procedures were covered: 25026, 25573, 30703, 36301-1, 37700-1, 37700-2, 42700, 60501, 60705, 61715, 61726, 62700-1, 62703, 71707, 71707-1, 71709, 71710, 71711, 71881, 72583, 72700, 72701, 90712, 92703 and 93702.

Results: Of the 15 areas inspected, several apparent violations were identified.

DETAILS

1. Persons Contacted:

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

Arizona Nuclear Power Project (ANPP)

*J. Allen, Plant Manager, Unit 1
L. Brown, Manager, Radiation Protection and Chemistry
F. Buckingham, Operations Manager, Unit 2
R. Butler, Director, Standards and Technical Support
B. Cederquist, Manager, Chemical Services
W. Fernow, Manager, Training
R. Gouge, Operations Manager, Unit 3
*J. Haynes, Vice President, Nuclear Production
*W. Ide, Plant Manager, Unit 2
*J. Kirby, Director, Site Services
R. Papworth, Director, Quality Assurance
*T. Schriver, Manager, Compliance
G. Sowers, Manager, Engineering Evaluations
E. Van Brunt, Jr., Executive Vice President
R. Younger, Operations Manager, Unit 1
O. Zeringue, Plant Manager, Unit 3

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

*Attended the Exit Meeting on March 10, 1988.

2. Previously Identified Items - Units 2 and 3.

a. (Closed) Followup Item (529/87-08-01): "Shutdown From Outside The Control Room" - Unit 2.

A shutdown from outside the control room was performed in accordance with procedure 73PA-2SF02, "Shutdown Outside Control Room (20% Power)" on February 20. The test was witnessed by the inspectors. No problems were observed and this item is closed.

b. (Open) IE Bulletin 85-03, (530/IB-85-03): "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings".

This bulletin was inspected previously in inspection report 50-530/87-25. The remaining concerns for closure of this bulletin were:

1) NRC staff acceptance of the design basis for the system and settings.

2) Resolution of certain concerns with work orders reviewed during the inspection.
3) Review of procedure 73PR-9ZZ04.

For the first item, the licensee has submitted the bulletin response for the systems in a letter dated June 30, 1986. The NRC sent requests for additional information (RAIs) to the licensee in letters dated September 17, 1986 and June 30, 1987. The licensee responded in letters dated October 27, 1986 and August 3, 1987. The licensee has submitted the final report on the bulletin program in a letter (Van Brunt to NRC) dated January 15, 1988. The design basis for the switch settings and the responses to the RAIs has not been evaluated by the NRC staff at the present time. This sub-item remains open.

The concerns of the inspector with respect to the work orders were resolved in discussions with the licensee. This sub-item is closed.

For the third item, procedure 73PR-9ZZ04, Rev. 0, "Valve Motor Operator Monitoring and Test Program" was reviewed. This procedure controls how the motor operators are maintained for the valves addressed in the bulletin. This procedure also ensures that the switch settings will not change without engineering evaluation. This procedure also includes a methodology for setting the switches on the motor operators. No problems were identified with the procedure. This sub-item is closed.

This bulletin remains open pending evaluation of the design basis for the valve switch settings.

3. <u>Review of Plant Activities.</u>

a. <u>Unit 1</u>

Unit 1 was in a refueling outage the entire inspection period. The reactor was brought critical at 9:26 PM, on March 5, 1988, to begin low power physics testing.

The outage recovery was delayed due to an inoperable control element assembly (see section 7.) and problems with Post Accident Sampling System operability.

b. <u>Unit 2</u>

Unit 2 operated essentially at 100% power during the inspection period until February 20, when the plant was shutdown to start it's first refueling outage. The outage is expected to last approximately 85 days. Major outage activities include the replacement of reactor coolant pump shafts and journal bearings, steam generator eddy current testing, integrated leak rate testing of the containment, and the installation of numerous plant modifications.

c. Unit 3

Unit 3 operated essentially at full power throughout the inspection period.

d. Plant Tours

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

- o Auxiliary Building
- o Containment Building
- o Control Complex Building
- o Diesel Generator Building
- 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 Specification and administrative control procedure requirements.

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

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

4. Equipment Lineups Valve and electrical breakers were verified to be in the position or condition required by Technical Specifications and Administrative procedures for the applicable plant mode. This verification included routine control board indication reviews and conduct of partial system lineups.

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

6. General Plant Equipment Conditions Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that would prevent the system 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. Housekeeping in the radiologically controlled area was evaluated with respect to controlling the spread of surface and airborne contamination.

    A tour of the Unit 2 fuel building prior to the receipt of new fuel was conducted by the inspector. The housekeeping condition of the working area associated with the receipt of new fuel was considered inconsistent with that operation. The observation was reported to the plant manager who informed the inspector that he had made a similar observation and had directed a cleanup effort. The inspector noted a much improved cleanliness condition prior to the receipt of the first new fuel bundle.

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

No violations of NRC requirements or deviations were identified.

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

Selected engineered safety feature systems (and systems important to safety) were walked down by the inspector to confirm that the systems were aligned in accordance with plant procedures. During the walkdown of the systems, items such as hangers, supports, electrical cabinets, and cables were inspected to determine that they were operable, and in a condition to perform their required functions.

Unit 1

Accessible portions of the following systems were walked down on the indicated date.

System	Date
Containment Spray System, Trains "A" and "B"	January 20 and March 1
Emergency Diesel Generator, Trains "A" and "B"	January 21 and March 2
Auxiliary Feedwater System, Trains "A" and "B"	January 21 and March 2
Boration Flow Paths	January 26

Unit 2

Accessible portions of the following systems were walked down on the indicated dates.

System	Date
Emergency Diesel Generator, Train "B"	January 21
Essential Cooling Water System, Train "A"	January 27
Auxiliary Feedwater System, Trains "A" and "B"	February 04
Fire Pump Walkdown	February 10
Shutdown Cooling, Train "B"	March 1
Emergency Boration	March 1

Unit 3

Accessible portions of the following systems were walked down on the indicated dates.

System	Date
Emergency Diesel Generator, Trains "A" and "B"	January 24
High and Low Pressure Safety Injection Systems, Trains "A" and "B"	February 24

No violations of NRC requirements or deviations were identified.

5. Surveillance Testing - Units 1, 2 and 3.

a. 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. Portions of the following surveillances were observed by the inspector on the dates shown:

Unit 1

Procedure	Description	Dates Performed
73ST-9CL04	Containment Air Lock Overall Leak Test.	January 20
72PA-9RX02	ExCore Linear Subchannel Gain Adjustment.	January 20
72ST-1RX09	Shutdown Margin	January 26
36ST-9SE04	ExCore Startup Channel Functional Test.	February 4
36ST-9SB04	RPS/ESFAS Logic Functional Test.	February 24
36ST-9HP03	Containment H2 Monitoring System Calibration.	March 2
73ST-9RX01	Rod Drop Time Testing.	March 2
36ST-9SB02	PPS Bistable Trip Units Functional Test.	March 3

Unit 2

Procedure	Description	Dates Performed
42ST-2AF02	Auxiliary Feedwater Pump Operability Test.	January 20
36ST-9SB41	Plant Protection System Transmitter Time Response Test.	January 20
36ST-2SE02	Excore Safety Linear Channel Quarterly Calibration.	January 27

73ST-9CL03	Containment Airlock Seal Leak Test.	February 03
73ST-9ZZ18	Main Steam PSV Set Pressure Verification.	February 12

Unit 3

Procedure	Description	Dates Performed
32ST-9ZZ03	4160 Bus Undervoltage Protective Relays	February 2
36ST-9SB02	PPS Bistable Trip Units Functional Test	February 11

No violations of NRC requirements or deviations were identified.

6. Plant Maintenance - Units 1, 2 and 3.

a. During the inspection period, the inspector observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required QA/QC 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. The inspector witnessed portions of the following maintenance activities:

Unit 1

Description	Dates Performed
o Control Element Drive Motor 56 Seal Weld Preparations.	February 6
o Control Element Extension Shaft Decoupling.	February 6

Unit 2

Description	Dates Performed
o Reassembly of Auxiliary (N) Feedwater Pump Motor Outboard Bearing.	February 10
o Disassembly of Main Steam Isolation and Main Feedwater Valve Hydraulic Controls.	February 23
o "A" Emergency Diesel Reassembly.	March 1

- o Inspection and Reassembly of MSIV/FW IV, 4-way Control Valves. — March 2

No violations of NRC requirements or deviations were identified.

7. <u>Inoperable Control Element Assembly - Unit 1</u>

On January 22, 1988, with Unit 1 in Mode 3 performing Control Element Assembly (CEA) Drop-Time Testing, CEA 56 did not drop as required when power was removed from the control element drive motor. After exercising the CEA up and down, it was fully inserted into the core. All other CEAs were tested satisfactorily.

On January 23, testing resumed on CEA 56 and it was determined that the CEA could be withdrawn but not reliably inserted. Further testing was delayed until entering Mode 5. When testing resumed in Mode 5, the CEA was moved out 10 inches but could not be inserted. The CEA was then moved to 30 inches withdrawn and still could not be inserted.

After further evaluation, the Control Element Drive Mechanism (CEDM) was removed and boroscope examinations were conducted of the accessible portions of CEA 56 and the Upper Guide Structure (UGS). Additional efforts to free the CEA were unsuccessful and the vessel head, the upper guide structure and CEAs were removed from the vessel.

Upon removal of the CEAs, a ball bearing was found at the bottom of the guide tube in CEA 56. A video inspection of the CEA fingers revealed marks on the finger and guide post above the guide post in which the ball bearing was found.

The licensee believed the source of the ball bearing to be from a multi-stud tensioner (MST) caster, as stated in the licensee's letter to Region V, "Justification for Continued Operation - Inability of CEA 56 to Drop", dated February 25, 1988. This event was discussed at length during an ANPP/NRC Management Meeting held on February 29, 1988. As documented in meeting report 50-529/88-11, at the time of the meeting, the licensee had not identified any specific failures of MST casters, which could have led to the introduction of the ball bearing into the UGS. The licensee was requested to review the MST caster maintenance history for records of past failures. Subsequent interviews with maintenance personnel revealed that a caster had failed during replacement, spilling numerous ball bearings in containment, prior to establishing cleanliness Zone 3 areas and prior to lifting the reactor vessel head for refueling. This further investigation was documented in the licensee's letter to Region V, "Request for Additional Information-Justification for Continued Operation", dated March 2, 1988.

Region V and NRR reviewed the above licensee letters and found no objection to continued operation of Palo Verde Unit 1. However, the lack of a thorough initial investigation into the source of the ball bearing and poor conduct of foreign material exclusion practices are viewed as deficiencies.

No violations of NRC requirements or deviations were identified.

8. Inoperable High Pressure Safety Injection Pumps During Mode 4 - Unit 1

On February 29, 1988, Unit 1 entered Mode 4 from Mode 5. An hour and twenty minutes after the mode transition, with the reactor coolant system temperature at approximately 280 degrees F, the Shift Supervisor noticed that both High Pressure Safety Injection (HPSI) pumps were inoperable due to their control power fuses being removed. Technical Specification 3.5.3 requires one HPSI pump to be operable in Mode 4. The mode transition was made following operating procedure 41OP-1ZZ01, "Cold Shutdown to Hot Standby Mode 5 to Mode 3," which required completion of the Mode 4 checklist per operating procedure 41OP-1ZZ11, "Mode Change Checklists".

Operating Procedure 41OP-1ZZ10, "Hot Standby to Cold Shutdown Mode 3 to Mode 5," requires both HPSI pump breakers to be placed in an inoperable status upon entering Mode 5. This is usually accomplished by removing the control power fuses. When the HPSI pumps are required to be operated in Mode 5, the fuses are replaced for the duration of the pump operation and removed when the pump is secured. Although HPSI pump operation is logged in the control room log, no entries are made as to the condition of the control power fuses. Thus after performing the HPSI surveillance tests 41ST-1SI07 and 41ST-1SI10, as required by the mode change checklist, the fuses were removed per normal practice without a procedure or documented configuration change.

When the mode transition was made, none of the control operators observed the various control board indications that control power was not available to either HPSI pump. The inspector was told that board walkdowns prior to mode changes are typically not performed if the mode change occurs on the same shift.

Further investigation into this problem revealed that on September 3, 1987, the procedure deficiency of not restoring the fuses required to be removed by 41OP-1ZZ10, was identified by a Shift Supervisor as a potential problem with 41OP-1ZZ01. The potential problem was documented using a procedure feedback form. This procedure feedback form was one of over 700 feedback forms which remained open as of March 2, 1988. The licensee had recently recognized the need to prioritize the feedback forms, but this practice was not in place on September 3. The inspector will further review the significance of the backlog of these forms during a future inspection.

Although the relative safety significance of this event was not great, the inspector observed that several opportunities existed for action to be taken to preclude the violation. Therefore, although the error was identified by the licensee, the inspector concluded that a citation for an apparent violation for entering and operating in Mode 4 without an operable HPSI pump is warranted (528/88-02-01).

9. Essential Cooling Pump Room Alarms - Unit 2.

During tours of the Unit 2 auxiliary building, the inspector often noted alarms sounding in the essential cooling pump rooms. The alarms sound when the following conditions exist with the radiation detectors that detect primary coolant leakage into the essential cooling water system, when the shutdown cooling system is in operation:

- o low sample flow
- o high sample activity
- o equipment failure

The alarm apparently is so common, due to the system normally being secured, that personnel have been observed entering into the room while the alarm was sounding, without knowledge of the cause for the alarm.

The inspector informed the licensee that the persistent alarm was creating a negative mind set with individuals who might ignore other alarms. Based on discussions with the licensee, the inspector was informed that an evaluation would be made to determine if the system could be modified so that the alarm would sound only when meaningful followup action was required, so that entrance into the room while the alarm sounded would be limited to legitimate investigations. No alarm condition should exist during plant operation, since the shutdown cooling system is shutdown. This item will be followed by the inspector (529/88-02-02).

No violations of NRC requirements or deviations were identified.

10. Control Room Annunciator Response - Unit 2

During an extended observation of Unit 2 Control Room activities, it was observed that operators were not expeditiously clearing the flashing lights from cleared alarm conditions on the annunciator panel, apparently because they knew that a number of "Bogus" annunciators would just alarm again within a short time. Further, when the inspector questioned an operator regarding whether a frequently clearing and recurring annunciator condition had been identified for correction in the maintenance request system, the operator expressed assurance that this was the case because the condition had been occurring for a long period of time. The discrepancy had actually not been entered into the maintenance request system for correction; this was subsequently accomplished.

The inspectors concluded that the operators have developed a degree of apathy toward the annunciators and annunciated conditions. The NRC recognizes that the licensee has initiated a program to eliminate "Bogus" annunciators. However, in the interim, it appears that the operators do not clearly understand what is expected by

ANPP management with regard to responding to annunciators. This concern was discussed with senior ANPP management.

No violations of NRC requirements or deviations were identified.

11. Operational Errors - Unit 2

a. Inadvertent Safety Injection Actuation Signal (SIAS) and Containment Isolation Actuation Signal (CIAS)

On February 21, 1988, following the shutdown of Unit 2, an inadvertent SIAS and CIAS were received during the cooldown of the reactor. The reactor was in Mode 5 at the time of the actuations, reactor coolant temperature was less than 200 degrees F and pressurizer pressure was being lowered. A review of the event disclosed that Step 4.3.114.2 of procedure 420P-2ZZ10, Revision 2, "Hot Standby to Cold Shutdown Mode 3 to Mode 5", which instructs the control room operator to bypass the pressurizer low pressure trips on all four Plant Protective System (PPS) channels when RCS temperature has decreased below 200 degrees F, was signed off when in fact only the "C" channel had been bypassed. While the pressurizer pressure was being lowered, the SIAS and CIAS were received when pressurizer pressure was at 127 psia. At the time of the event, the high pressure safety injection pumps (HPSI) had been de-energized in accordance with procedures and both trains of low pressure safety injection pumps (LPSI) were already operating in the shutdown cooling mode. The actuations did start the containment spray pumps (injection does not occur unless a containment high pressure is received), and approximately 10% of the safety injection tanks injected into the reactor coolant system.

All systems functioned as required with the exception of one of the high pressure safety injection valves, which only partially opened before its fuse blew. This matter is under investigation by the licensee.

Step 4.3.114.3 of procedure 420P-2ZZ10 states, "Jumpers Maybe Installed in PPS per 36MT-9SB04, ESF Jumper Installation and Removal, to Prevent Inadvertent ESFAS actuations". This step was not implemented, however it had been signed off to indicate an awareness that the option was available.

This condition went unnoticed by all control room personnel during shift turnover. Subsequently the safety injection pre-trip annunciator was received and acknowledged without followup, five minutes prior to the safety injection actuation. Administrative procedure 40AC-9ZZ02, "Conduct of operations" directs the control room to communicate plant status during shift turnovers and respond to abnormal indications until corrected or verified to be false. As noted in sections 9 and 10 of this report, poor response to annunciators was noted prior to this event.

The failure to bypass the pressurizer low pressure trips is considered an apparent violation of operating procedure 42OP-2ZZ10 (529/88-02-03).

b. Inoperability of One of the Auxiliary Feedwater Pumps

On February 21, 1988, following the Unit 2 shutdown, an attempt was made to use auxiliary feedwater pump AFN-P01. The control room operators noted that no flow was being delivered to the steam generators. Two other auxiliary feedwater (AFW) pumps were available, one of which was then placed in service.

An investigation into the problem revealed that the discharge valve of auxiliary feedwater pump AFN-P01 was closed. A review of the matter disclosed that the valve had probably been closed since February 10, 1988, when the pump was intended to be returned to an operable status following repair. The repair involved the replacement of the outboard motor bearing, which had failed following a routine preventive maintenance (PM) replacement of the bearing lubricating oil. During the test run following oil replacement, the operating performance of the bearing was suspect and the pump was shutdown. An inspection of the bearing revealed it had failed. Oil samples were taken and submitted to the laboratory for analysis as part of the licensee's evaluation into the cause of the failure. To date the results have not returned. The inspector will follow this matter as part of the routine inspection program.

Restoration step 8.1.13 of surveillance procedure 42ST-2AF01, Revision 1, instructs that discharge valve No. AF-V013 be opened and locked. It had been signed off as completed. The valve change record which documents the change/restoration of valves revealed a sign-off that the valve had been opened on February 10, 1988. In addition, a second sign-off signifying that an independent check of the valve position had been made on the same date, was also documented.

Operation of Unit 2 in Modes 1, 2, and 3, with less than the three independent AFW pumps required by technical specification 3.7.1.2, is an apparent violation (529/88-02-04).

The inspector considered the safety significance of the event. Throughout the event the two safety related AFW pumps were available. Each of the pumps are 100% capacity pumps. Additionally, although Technical Specification 3.7.1.2 requires all three AFW pumps to be operable, pump AFN-P01 has no automatic start capability. The inspector concluded that the event had resulted in a reduction of redundancy of the AFW system, however the direct safety significance of this event alone was not high in that two 100% capacity safety-related pumps remained available.

Further investigation by the inspector of valve AF-V013 showed that the stem position rod extended beyond the valve body

approximately 8" when the valve is in the closed position. This is inconsistent with a stem position rod extension of approximately 7" for the Units 1 and 3 valves in the open position. The licensee suspects that the position rod may have misled the operators. The licensee is considering modifying the position rod at Unit 2.

12. Fuel Receipt and Storage - Unit 2

The inspector witnessed several unloadings, inspections, and storage of new fuel bundles. Unit 2 is scheduled to load 108 new fuel bundles during its first refueling outage. The inspector observed that container unloadings, fuel inspections and fuel movements were conducted in accordance with approved procedures. Radiation controls were being implemented and records of fuel inspections, fuel movements and material control, revealed no anomalies.

No violations of NRC requirements or deviations were identified.

13. Preparation For Refueling - Unit 2

The first refueling outage at Unit 2 commenced on February 20, 1988. The inspector verified that procedures covering critical operations such as fuel receipt, inspection and storage; fuel loading, fuel transfer and core verification; vessel head and internals removal; fuel pool level monitoring; shutdown margin determination; and decay heat removal, were available for implementation.

In addition, a refueling outage handbook highlighting administrative controls, outage schedules and staffing resources was issued in support of the outage.

No violations of NRC requirements or deviations were identified.

14. Review of Licensee Programs for Followup of NRC Information Notices and Bulletins.

The inspector held discussions with licensee personnel and reviewed program procedures governing the followup and tracking of NRC Information Notices and Bulletins. The inspector reviewed program status lists for NRC Information Notices and Bulletins issued during the past two years. Nine Information Notice closeout packages were also reviewed. The inspector found the licensee's tracking systems to provide adequate controls to ensure the review of Information Notices and Bulletins for applicability to the plant, the distribution of both Notices and Bulletins to the appropriate personnel at the corporate and site levels, and the resolution of action items resulting from these reviews. Of the nine closeout packages reviewed, it was found that in all cases the actions taken by the licensee were appropriate. The inspector did express a concern that the licensee had begun to accumulate a sizeable backlog of information notices which had not yet completed the licensee's review cycle. In a number of cases, a response from the licensee's engineering organization back to the licensee's licensing group took between six to nine months from the time the Information Notice was issued. The inspector informed the licensee that efforts would be made to improve the timeliness of the engineering evaluations in this area. The licensee's efforts will be followed by the inspector as a part of the routine inspection program.

No violations of NRC requirements or deviations were identified.

15. NRC Bulletin No. 87-02 "Fastener Testing to Determine Conformance with Applicable Material Specifications".

On November 6, 1987, the NRC issued NRC Bulletin 87-02, "Fastener Testing to Determine Conformance with Applicable Material Specifications." The Bulletin requested that licensees 1) review their receipt inspection requirements and internal controls for fasteners and 2) independently determine through testing, whether fasteners (studs, bolts, cap screws and nuts) in stores at their facilities meet required mechanical and chemical specification requirements.

Specifically, the Bulletin requested that licensees select a sample of 10 safety related fasteners (studs, bolts, or cap screws) and 10 non-safety related fasteners, including in the sample typical nuts to be used with each fastener, for testing. The testing requirements for the fasteners and nuts were specified in the Bulletin. Prior to this inspection period, the licensee had completed its sample selection and had shipped the fasteners and nuts to a contractor to be tested. The inspector participated in the sample selection during the prior inspection period. The licensee's test instructions were also previously reviewed.

During this inspection period, the licensee submitted the results of their testing program as well as their analysis of current receipt inspection requirements and internal controls for fasteners. A review of the testing results submitted by the licensee found that all items selected met both mechanical and chemical specification requirements, with the exception of one A-307, Grade B, #25 Bolt, which was found to have a slightly higher average hardness. This minor deviation was not considered to be safety significant.

The inspector reviewed the licensee's program and procedures for receipt inspection and internal control of fasteners and compared it to the licensee's descriptions, as provided in the bulletin response. The inspector confirmed that the licensee's program and procedures do indeed require inspections on a sample basis, by quality control personnel during receipt inspection, of fastener characteristics such as head markings, size, number of threads per inch, plating, head type, Rockwell hardness, packaging and applicable documentation, i.e. certified material test reports or certificates of conformance. The inspector also reviewed procedures for control within the warehouse and issuance to the field. The inspector found that documentation for all safety related fastener, was required to be re-verified prior to issuance of any fastener to the field.

Based on the licensee's response to the Bulletin and the inspectors review, this item is considered closed.

No violations of NRC requirements or deviations were identified.

16. Followup Licensee Event Report (LER) - Units 1, 2 and 3.

The following LER was reviewed by the inspector. Based on the information provided in the report, it was concluded that reporting requirements had been met, root causes had been identified, and corrective actions were appropriate. The below listed LER is considered closed.

Unit 1

LER NUMBER	DESCRIPTION
87-15	Surveillance Interval Exceeded for Three Containment Isolation Valves Due to Personnel Error.

This LER relates to the failure to perform surveillance testing of three containment isolation valves in accordance with Technical Specification 4.0.5, which requires testing in accordance with Section XI of the ASME Boiler and Pressure Vessel Code. The three valves met the required acceptance criteria; however, the stroke times measured had increased by more than 50% from the previous tests. The valves are required to be tested once per 3 months; however, when stroke times increase by 50% or more relative to the previous test, ASME Section XI requires testing frequency to be adjusted to a monthly interval. The testing schedule was not modified to meet the monthly surveillance interval for the three valves. The root cause for the event was evaluated by the licensee as having been due to cognitive personnel error by the test engineer responsible for tracking the completed test. The licensee concluded that the engineer should have been able to compare the valve stroke time results within sufficient time to modify the test schedule as necessary. The administrative controls in this area were evaluated by the licensee as providing sufficient guidance in this area.

During this inspection, the inspector reviewed the administrative controls related to the scheduling and testing of valves in accordance with ASME Section XI. Two administrative control procedures, in particular were reviewed, 73AC-0ZZ30, "In-service Testing of Safety Related Pumps and Valves", and 73AC-9ZZ04, "Surveillance Testing". The inspector observed that a potential did exist in some cases for a less than timely technical review of some valve performance tests to occur due to the use of test procedures which test a multiple number of valves and which allow for partial performance of the procedure to occur over an extended period of time, with the final technical review not being completed until the procedure is completed. Although no specific regulatory requirements exist with regard to the timeliness of test results review for Section XI valve testing, the inspector discussed his observations with the cognizant engineering supervisor responsible for the review and scheduling of Section XI testing, noting that there did appear to be the potential for the technical review of valve test results not to occur within sufficient time to modify the test schedule when so dictated by a change in valve stroke time. The engineering supervisor acknowledged the inspector's concerns, informing the inspector that changes to the organization of the valve test procedures were underway which would, among other things, reduce the number of valves tested within a single procedure. The licensee stated that these changes, along with current test tracking by the Surveillance Program Control Group, should result in improvements in the timeliness of the completion and review of Section XI valve testing. The inspector will continue to monitor the licensee's efforts in this area as a part of the routine inspection program. This LER is closed.

No violations of NRC requirements or deviations were identified.

17. <u>Review of Periodic and Special Reports - Units 1, 2 and 3.</u>

Periodic and special reports submitted by the licensee pursuant to Technical Specifications 6.9.1 and 6.9.2 were reviewed by the inspector.

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

<u>Unit 1</u>

o Monthly Operating Report for January, 1988.

<u>Unit 2</u>

o Monthly Operating Report for January, 1988.

<u>Unit 3</u>

o Monthly Operating Report for January, 1988.

No violations of NRC requirements or deviations were identified.

18. <u>Exit Meeting</u>

The inspector met with licensee management representatives periodically during the inspection and held an exit interview on March 10, 1988. During the exit meeting, the inspector discussed recent operating experiences involving personnel error, emphasizing the need for greater attention to detail and management oversight.