U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No: 50-397/92-09

Docket No: 50-397

License No: NPF-21

Licensee: Washington Public Power Supply System
P. O. Box 968
Richland, WA 99352

Facility Name: Washington Nuclear Project No. 2 (WNP-2)

Inspection at: WNP-2 site near Richland, Washington

Inspection Conducted: March 9 - April 19, 1992

Inspectors: R. C. Sorensen, Senior Resident Inspector

D. L. Proulx, Resident Inspector

Approved by: P. H. Johnson, Chief — 5/14/92 Date Signed
Reactor Projects Section 1

Summary:

Inspection on March 9 - April 19, 1992 (50-397/92-09)

Areas Inspected: Routine inspection by the resident inspectors of control room operations, operational safety verification, engineered safety features, surveillance program, maintenance program, licensee event reports, special inspection topics, and procedural adherence. During this inspection, Inspection Procedures 61726, 62703, 71707, 71710, 90712, 92700, 92701, 92702 and 93702 were used.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Significant Safety Matters: None.

Summary of Violations and Deviations: Three violations and one deviation were identified. The violations involved (1) a high-high radiation area not posted with a flashing light as a warning device, (2) failure to

follow maintenance procedures for makeup of a seismic restraint in the standby liquid control (SLC) system, and (3) not providing timely corrective action to ensure that SLC pump lubricating oil level was maintained above the low level mark. The deviation concerned the licensee's not establishing correct setpoints to maintain the temperature of the SLC sodium pentaborate storage tank within the range committed in the FSAR.

Open Items Summary:

Twelve LERs were closed; five new items (including the deviation and three violations summarized above) were opened.

DETAILS

1. Persons Contacted

L. Oxsen, Deputy Managing Director
V. Parrish, Assistant Managing Director for Operations
*J. Baker, Plant Manager
L. Harrold, Assistant Plant Manager
*G. Sorensen, Regulatory Programs Manager
*J. Wyrick, Outage Manager
*D. Pisarcik, Health Physics and Chemistry Manager
S. McKay, Operations Manager
*D. Feldman, Assistant Maintenance Manager
*A. Hosler, Licensing Manager
*P. McBurney, Acting Quality Assurance Manager
*J. Peters, Administrative Manager
W. Shaeffer, Assistant Operations Manager
*R. Webring, Plant Technical Manager
*D. Walker, Industrial Safety and Fire Protection Manager
*M. Reis, Compliance Supervisor
*S. Stave, Acting Planning and Scheduling Manager

The inspectors also interviewed various control room operators, shift supervisors and shift managers, and maintenance, engineering, quality assurance, and management personnel.

*Attended the Exit Meeting on April 22, 1992.

2. Plant Status

At the beginning of the inspection period, the plant was in cold shutdown due to design modifications being made to the containment atmospheric control (CAC) system. After completion of the modifications and the required testing, the plant was restarted on March 18th. The reactor achieved 100% power on March 21 and remained at full power until April 17, when the reactor was shut down for the R7 refueling outage. The shutdown appeared well coordinated and was accomplished without incident. The plant was in cold shutdown at the end of the inspection period.

3. Injury of an Electrician Due to an Electrical Fault (93702)

On the morning of March 8, 1992, an electrician was injured due to a fault in a disconnect cubicle in which he was working. The cubicle was located in motor control center (MCC) MC-6A and was providing power to turbine building fan TEA-FN-1D, a 480 VAC non-safety related load. The electrician was conducting inspection and cleaning of the disconnect cubicle per PPM 10.25.12, "Inspection of AC Motors, Controllers, and Generators." Apparently, a common paintbrush was being used to clean the cubicle, as one was found at the scene in a severely charred condition. This type of activity is conducted routinely at WNP-2 with MCCs still energized, as was the case in this event.

Electricians conducting the cleaning and inspection are expected to open a specific disconnect in the cubicle to deenergize all of the circuitry powered from the disconnect. This action was completed for this cubicle prior to the event. However, three conductors enter the cubicle at the top and end in junctions just above the disconnect. These conductors and junctions were still energized with the disconnect open. Apparently, the electrician involved reached the paintbrush into that area and caused a phase-to-phase short circuit between two of the energized phases. Although current did not pass through his body, the resulting fireball caused severe burns to his face, right hand and shoulder, and back. The burns to his back were apparently the result of the fireball reflecting from the corrugated metal sheeting behind him. The plant emergency team responded promptly and the electrician was transported to the local hospital. He was later transmitted to a burn unit in Seattle.

The disconnect cubicle suffered major damage. Some surrounding cubicles in MC-6A also suffered damage. The licensee formed a special committee by procedure, headed by a member of corporate management, to investigate the event.

The inspector reviewed PPM 10.25.12 and inspected the damaged buswork a few hours after the incident. The inspector noted that PPM 10.25.12, as written, intended for the cleaning of such electrical switchgear to be accomplished by vacuuming. There was no provision for use of a paintbrush.

The inspector discussed the incident with the plant manager and the electrical maintenance supervisor. This event was another instance of electrical safety problems that have occurred at WNP-2 over the last several years. This issue was also discussed with licensee management during the management meeting held on March 27, 1992 (see Meeting Report No. 92-11).

The buswork was subsequently repaired. The inspector will continue to follow the licensee's corrective actions regarding this event.

In that the work performed was not associated with safety related equipment, no violations of NRC requirements were identified.

4. Operational Safety Verification (71707)

a. Plant Tours

The following plant areas were toured by the inspectors during the course of the inspection:

- Reactor Building
- Control Room
- Diesel Generator Building
- Radwaste Building
- Service Water Buildings
- Technical Support Center
- Turbine Generator Building
- Yard Area and Perimeter

b. The following items 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. The attentiveness of the operators was observed in the execution of their duties and the control room was observed to be free of distractions such as non-work related radios and reading materials.

(4) Equipment Lineups. 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. This verification included routine control board indication reviews and conduct of partial system lineups. Technical Specification limiting conditions for operation were verified by direct observation.

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

(6) General Plant Equipment Conditions. Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that would prevent the system from fulfilling its functional requirements. Annunciators were observed to ascertain their status and operability.

(7) Fire Protection. Fire fighting equipment and controls were observed for conformance with administrative procedures.

(8) Plant Chemistry. Chemical analyses and trend results were reviewed for conformance with Technical Specifications and administrative control procedures.

(9) Radiation Protection Controls. The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors also observed compliance with Radiation Work Permits, proper wearing of protective equipment and personnel monitoring devices, and personnel frisking practices. Radiation monitoring equipment was frequently monitored to verify operability and adherence to calibration frequency.

On March 18, 1992, during a tour of the reactor building, the inspector noted an area that was roped off and posted as a high-high radiation area that did not have an operational flashing light at the area boundary as required by the Technical Specifications. There were no provisions for locking or guarding the area or providing other compensatory actions. The inspectors informed the health physics (HP) technician and inquired whether the area had been downgraded from a "High-High Radiation Area" (greater than or equal to 1000 mrem/hr) to a "High Radiation Area" (greater than 100 mrem/hr but less than 1000 mrem/hr). The licensee performed surveys and verified a dose rate of approximately 2000 mrem/hr.

The licensee stated that they have had chronic problems with the reliability of this design of flashing light. Subsequently, the licensee installed two flashing lights at the high-high radiation area boundary to meet the requirements of the Technical Specifications. Other corrective actions the licensee was considering included drilling holes in the lights for improved heat dissipation and the purchase of more reliably designed lights. In addition, a PER was written to document the problems with controlling high-high radiation areas, and to discuss possible solutions to the problems (e.g., shielding, flushing to remove the source).

Because the high-high radiation area did not have an operational flashing light to warn personnel as required by the Technical Specifications, nor were any compensatory actions taken, this condition appeared to violate section 6.12.2 of the TS (Violation 397/92-09-01).

(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.

In general, plant housekeeping appeared to meet licensee requirements. However, after the plant was placed in Mode 2 (startup) on March 18, the inspector toured the reactor building and noted several instances of unsecured handcarts and tool boxes left astray, ladders leaning against safety related equipment, and chainfalls left unattended. Furthermore, the inspector noted that the shield blocks that constitute the floor boundary between the 471' level and 441' level above the residual heat removal (RHR) pump rooms were not in place. These conditions appeared to be a result of the licensee's modifications of the CAC drain lines, but had not been restored prior to plant restart.

The inspector apprised the Assistant Plant Manager of these observations. Subsequent licensee investigation revealed that the Shift Manager on the graveyard shift on March 18 had been aware that the shield blocks were not in place and had

contacted a compliance engineer to determine whether plant startup could commence with the shield blocks removed from both RHR pump rooms. The Shift Manager reportedly was told, after research was conducted by the shift technical adviser (STA), that the FSAR did not address the shield blocks, and plant startup was subsequently commenced.

The shield blocks (described above, that were not in place on March 18) serve as a flooding and fire protection boundary between the A and B trains of the RHR system. This was determined later that day. The licensee evaluated this degraded plant configuration and determined this condition to be a reportable event pursuant to 10 CFR 50.72 and 10 CFR 50.73 due to the potential for common mode failure of two trains of RHR. This issue will be reviewed further during inspector followup on the licensee event report.

(11) Security. The inspectors periodically observed security practices to ascertain that the licensee's implementation of the security plan was in accordance with site procedures, that the search equipment at the access control points was operational, that the vital area portals were kept locked and alarmed, and that personnel allowed access to the protected area were badged and monitored and the monitoring equipment was functional.

c. Engineered Safety Feature Walkdown

Selected engineered safety features (and systems important to safety) were walked down by the inspectors to confirm that the systems were aligned in accordance with plant procedures. During the walkdown of the systems, items such as hangers, supports, electrical power supplies, cabinets, and cables were inspected to determine that they were operable and in a condition to perform their required functions. Proper lubrication and cooling of major components were also observed for adequacy. The inspectors also verified that certain system valves were in the required position by both local and remote position indication as applicable.

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

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3.	April 6
Hydrogen Recombiners (CAC)	April 7
Low Pressure Core Spray (LPCS)	March 16
High Pressure Core Spray (HPCS)	March 16
Reactor Core Isolation Cooling (RCIC)	April 14

Residual Heat Removal (RHR), Trains "A" and "B"	March 16
Scram Discharge Volume System	April 6
Standby Gas Treatment System	April 8
Standby Liquid Control (SLC) System	March 17-20
Standby Service Water System	April 8
125V DC Electrical Distribution, Divisions 1 and 2	April 13
250V DC Electrical Distribution	April 13

One violation was identified, as discussed in Section b(9) above.

5. Surveillance Testing (61726)

a. Surveillance tests required to be performed by the Technical Specifications (TS) were reviewed on a sampling basis to verify that: (1) a technically adequate procedure existed for performance of the surveillance tests; (2) the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and (3) test results satisfied acceptance criteria or were properly dispositioned.

b. Portions of the following surveillance tests were observed by the inspectors on the dates shown:

Procedure	Description	Dates Performed
7.4.6.6.1.5	18 Month CAC Operability Check	March 11
7.4.4.3.2.3.6	HPCS-RCS Interface Valve Leakage Check	April 16
7.4.8.3.2	AC/DC Breaker Alignment Checks	April 17

In addition, the inspector reviewed several other completed surveillance procedures as discussed in paragraph 7 of this inspection report.

No violations or deviations were identified.

6. Plant Maintenance (62703)

During the inspection period, the inspector observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements and with administrative and maintenance procedures, required QA/QC involvement,

proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspector verified that reportability for these activities was correct.

The inspector witnessed portions of the following maintenance activities:

Description	Dates Performed
AR-6513, Inspect/Repair FP-P-2A	April 13
PPM 10.27.45, Calibrate SLC-TIC-2	April 14
AR-2880, Replace Viton Seals for WMA-EHO-TCV/12A	April 17

No violations or deviations were identified.

7. Walkdown of Standby Liquid Control (SLC) System (71710)

The inspector performed a detailed walkdown of the SLC system to ascertain that the system was lined up properly, material deficiencies were being identified and promptly corrected, and that surveillance and test procedures and results conformed to the Final Safety Analysis Report (FSAR) and the Technical Specifications (TS). The inspector researched various reference materials such as vendor manuals and isometric drawings. Although the system appeared to meet NRC requirements for operability, the inspector noted the following deficiencies:

a. The inspector reviewed PPM 7.4.1.5.3, "SLC Pumps Operability Test," on March 18, 1992 to determine if the procedure met the requirements of the TS and if the pumps met the procedural requirements for operability. Attachment 9.5 of PPM 7.4.5.1.3 prescribed that the static level for the SLC pump motor lubricating oil remain at 3-3/4 to 4 inches above the centerline of the sightglass nipple. The inspector observed that the oil level for SLC-P-1B was at 3-1/2 inches. This was below the minimum level as prescribed by this PPM. The inspector informed the Shift Manager, who declared SLC-P-1B inoperable, as required by PPM 7.4.5.1.3. Maintenance personnel immediately added oil to the pump's motor to return the oil to the proper level, and the pump was declared operable. The licensee contacted the vendor to ensure that the level in the pump would not have caused damage. The vendor recommended that the licensee maintain the lubricating oil level from 3-3/4 to 4 inches. However, the vendor stated that the SLC pumps could be run without damage if the static oil level was as low as 3 inches above the reference point. The licensee subsequently modified PPM 7.4.1.5.3 to allow for a static oil level of 3-1/4 to 4 inches.

The inspector also observed that both SLC pumps appeared to be leaking lubricating oil from their motors, as standing oil was evident around the pumps and motors. This condition had existed for months. Deficiency tags (dated April 10, 1991) that had previously identified this condition were affixed to each of these pumps. However, corrective action had not been initiated as of March 18,

1992 to prevent the static oil level from falling below the band prescribed in PPM 7.4.5.1.3, possibly impacting operability as then defined in PPM 7.4.5.1.3. This lack of corrective action is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. (Violation 397/92-09-02)

b. The inspector conducted walkdowns of the SLC seismic supports in accordance with the applicable design drawings. In addition, the inspector used a copy of PPM 10.2.29, "Installation, Modification, and Inspection of Pipe Supports," as guidance. No instances were identified in which deficient supports rendered either train of SLC inoperable. However, the U-bolt for support 4453-13 was loose, the nuts were loose, and a gap of approximately 1/2" existed between the U-bolt and the associated SLC piping in the vertical plane. PPM 10.2.29 requires that U-bolts have a maximum gap of 5/32 of an inch in the vertical plane for the applicable orientation. The inspector expressed concern about this condition because the support was on the common reactor vessel injection line that serves both trains of SLC. The licensee was notified and a PER was written for evaluation and correction of this condition.

The licensee's engineering staff determined that both trains of SLC were operable despite this degraded condition because, fortunately, the restraint was designed to prevent movement in the horizontal plane. It was apparent that restraint 4453-13 was loosened during performance of PPM 10.10.2, "Standby Liquid Control Squib Valves Test and Replacement." This procedure accomplished batch testing and replacement of charges for the SLC squib valves, as required by TS. The procedure directed unbolting of certain U-bolts to remove the squib valve. Step B.7 of PPM 10.10.2 states: "Loosen the hanger U-bolts on both cross-ties and vertical run enough to spread the valve flanges." After replacement of the squib valves, and following system restoration, PPM 10.10.2, step B.32 states "Retighten the hanger U-bolts." It appears that this step was not completed on May 23, 1991, when PPM 10.10.2 was last performed. Further, PPM 10.10.2 did not incorporate the guidance from PPM 10.2.29 for strict configuration of the U-bolts to ensure seismic integrity. Upon notification, the licensee configured support 4453-13 per PPM 10.2.29. Hanger 4453-13 not being configured per 10.2.29, nor being restored properly per PPM 10.10.2, appears to violate TS 6.8.1 in that the licensee did not follow approved safety-related maintenance procedures (Violation 397/92-09-03).

The inspector also noted that the detailed drawings for seismic supports 4452-12 and 4452-71A described the wrong type of support. The applicable isometric drawings and Burns and Roe calculation 8.14.156 require each of these supports to be spring can type supports, and spring can type supports were actually installed. However, the detail drawings for supports 4452-12 and 4452-71A were drawn as a U-bolt support and a box type support, respectively. Licensee representatives stated that many such detailed drawings were not fully updated by Burns and Roe during the late stages of design and construction. They stated that the Supply System would

continue to update these detailed drawing deficiencies as they are identified.

c. FSAR Section 9.3.5.2 describes the design features of the SLC sodium pentaborate storage tank, and measures taken to ensure the sodium pentaborate remains in solution. This section states, in part: "The saturation temperature of the solution is 67 degrees at the maximum concentration of 15% ... an automatic electrical resistance heater system provides heat to maintain the solution at 80 to 90 degrees to prevent precipitation during storage." On April 13, 1992, the inspector noted that the adjustable set points on controller SLC-TIC-2, which regulates SLC tank temperature by energizing and de-energizing the resistance heaters stated above, were set at 77 and 92 degrees. The licensee conducted an operational recalibration of SLC-TIC-2 and confirmed that SLC tank temperature was indeed being controlled between 77 and 92 degrees. Although there was no evidence that precipitation of the boron solution had occurred, or that the SLC system was inoperable, the inspector noted that the setpoint at which the heaters would energize was set in the nonconservative direction (less than the value committed to in the FSAR), thus decreasing the operating margin from precipitation of the solution. This condition appears to be a deviation from the SLC tank temperatures committed to in the FSAR (Deviation 397/92-09-04).

The licensee restored the setpoints of SLC-TIC-2 to those committed to in the FSAR by the end of the inspection period.

d. PPM 7.4.1.5.3 implements the requirements of ASME Section XI for inservice testing of the SLC pumps, as required by TS 4.0.5. This procedure directs the user to determine the flow rate of the SLC pumps by pumping demineralized water into the SLC test tank and calculating the flow rate by measuring the change in tank level over a certain time period. The inspector questioned the accuracy of this test because the change in test tank level was measured by a commercially purchased measuring tape that was loosely secured to the bottom of the tank's sightglass by masking tape, and was not affixed at all at the top of the sightglass. The measuring tape also appeared to be at a slight angle with respect to the sight glass. This method of measurement did not appear to meet the intent of ASME Section XI paragraphs 4100-4160 which describes precise instrumentation that meets calibration and accuracy standards, and should be permanently mounted, where applicable.

The inspector noted that when PPM 7.4.1.5.3 was performed on January 26, 1992 the calculated flow rate for SLC-P-1A was 41.8 gpm, just above the TS minimum of 41.2 gpm. Since the test tank holds 4.91 gallons per inch, a measurement error of only 1/4 of an inch (for 2 minutes of running time) could render the results of that test unsatisfactory. The licensee stated that the level measurement appeared to be accurate within this amount of tolerance despite the questionable measurement practices, and the test had been performed satisfactorily. However the licensee stated that a design change was being considered to permanently mount a gauge on the SLC test tank sightglass for level measurement during surveillances.

e. PPM 7.4.1.5, "Standby Liquid Control Injection Functional Test," requires the SLC system to be initiated from the control room, and to inject demineralized water into the reactor vessel. It also directs the user to perform PPM 10.10.2 and attach the completed copy of PPM 10.10.2 for records retention. Step 36 of PPM 7.4.1.5 implements TS 4.1.5.d.1, which requires that after the squib valve is fired it shall be replaced with a new charge from the same batch as the one fired, or from another batch in which a charge has been successfully fired. PPM 10.10.2 step 8.c requires the user to attach a copy of the manufacturer's certified test-firing data sheet, or a copy of the maintenance work request (MWR) that performed the batch test to the completed copy of PPM 10.10.2. The completed copy of 10.10.2 dated May 23, 1991 did not contain this documentation and the inspector was unable to ascertain whether this TS requirement was met.

In addition, ASME Section XI, paragraph IWV-3160, "Explosively Actuated Valve Tests," states, in part, "if a charge fails to fire, all charges from the same batch number shall be removed, destroyed, and replaced with charges from a fresh batch from which a sample charge shall have been tested satisfactorily." PPM 10.10.2 provides no procedural direction for the user to meet this ASME requirement, and the inspector was unable to determine whether previous unsatisfactory test firings (if any) were dispositioned properly. Since the inspector was unable to obtain test firing documentation by the end of the inspection, the issues discussed in this paragraph will be reviewed during a future inspection (Followup Item 397/92-09-05).

f. Several instances existed in which boric acid crystals appeared to be building up on SLC system components due to leaks in the system. The following components were identified with this condition:

- The suction flanges to both SLC pumps.
- Valves SLC-V-1A, SLC-V-1B, SLC-V-2A, SLC-V-2B, SLC-V-31, and SLC-V-18.

The licensee issued deficiency tags for each of these apparent leaks and will assess appropriate corrective action in the future.

Two violations and one deviation were identified.

8. <u>Qualified Life Expired for RHR Pumps "A" and "B" Motor Thrust Bearings (92701)</u>

On April 1, a problem evaluation request (PER) identified a potential problem involving the qualified life of the RHR "A" and "B" pump motor thrust bearings. General Electric (GE) had originally qualified these bearings for one year of <u>continuous</u> operation. This includes a design requirement of six months of post-LOCA operation. Early in plant construction, the licensee had assumed that each pump would be operated about three weeks per year for shutdown cooling. This would mean that the bearings would be qualified for about 8.6 years of plant operation, and a preventive maintenance task was developed to replace the bearings.

However, actual running time on these pumps for shutdown cooling has been much more than initially predicted, reducing the qualified life to about four years. Therefore, because of invalid assumptions made by the licensee during plant construction, the qualified life for the bearings has expired.

The licensee prepared a Basis for Continued Operation (BCO) to justify their view of the acceptability of this situation. The qualification methodology originally used by GE was based on a statistical design life called L-10. L-10 is the lifetime that 90% of a large population of identical bearings would be expected to achieve. L-10 methodology was established by the Antifriction Bearing Manufacturer's Association. Apparently, L-10 can be influenced by such factors as bearing lubrication. The licensee pointed out in their BCO that the lubricating oil for the pump motor bearings is changed every 2.5 years and is inspected monthly. The BCO provided justification for establishing an alternate type of qualification methodology based on performance monitoring. As stated in the BCO, this methodology is based on IEEE 323, which endorses periodic inservice surveillance methods such as vibration monitoring for determining qualified life of the bearings. The licensee noted in the BCO that vibration monitoring data had displayed no adverse trends since 1985. Bearing temperatures over a representative three year period also had also remained relatively constant.

The inspector noted that the qualification methodology used must be able to predict, in advance, when bearing replacement would be necessary, given that the bearings must survive six months of post-LOCA operation. The inspector questioned whether performance monitoring could accomplish this. The inspector also noted that:

- The bearing oil is not changed as often as GE recommends in the vendor manual; i.e., one or twice per year unless severe conditions warrant more frequent change.

- The monthly inspection of the lube oil merely consists of checking for high oil level, and if detected, checking for the existence of water. This inspection is not a quantitative measurement and barely qualifies as a qualitative measurement.

- RHR pumps "A" and "B" are run frequently, at times daily, for periods of several hours for the purpose of suppression pool cooling. These additional hours of running time evidently were not considered in the BCO.

GE was later able to show that <u>two</u> years of continuous operation were acceptable. The licensee subsequently undertook an effort to account for all of the hours that the pumps had operated for suppression pool cooling, in addition to shutdown cooling. This turned out to be an exhaustive search due to the lack of precise data. This search concluded that the "A" pump was within the acceptable two year criterion, but the "B" pump had accumulated more operating time, such that it was impacting the six month margin for post-LOCA operation. (The "B" RHR pump will be relied upon heavily during refueling outage R-7 when the core is off-loaded into the spent fuel pool). It appeared, however, that there would

be sufficient margin for operation of the "B" pump during the outage, based on statistical qualification methodology, given that the pump will not be needed for post-LOCA considerations during that time. The licensee indicated that they would confirm the validity and credibility of their position concerning qualification by performance monitoring to resolve this issue before plant restart, and did not rule out replacing the pump motor bearings.

No violations or deviations were identified.

9. Licensee Event Report (LER) Followup (90712, 92700)

The following LERs associated with operating events were reviewed by the inspectors. 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 LERs are considered closed.

LER NUMBER	DESCRIPTION
91-29-01	Inadequate Primary Containment Hydrogen Recombiners Recycle Flow Control
92-02	Main Steam Leakage Control (MSLC) System Inoperable Due to Inadequate Testing and Calculations
92-05	Inadequately Sized Thermal Overloads for Class 1E Motors
92-06	Reactor Building to Suppression Chamber Vacuum Breaker Setpoints Incorrectly Set
92-07	Primary Containment Hydrogen Recombiners Inoperable Due to Flooding/Drainage Problems
92-08	SGT (Standby Gas Treatment) System Fan Flow Limiter Setpoint Error
92-09	CIA (Containment Instrument Air) Pressure Switch Setting Changes Required Due to Revised Setpoint Calculation
92-10	SGT System Differential Pressure Controller Setpoint Error
92-11	Tech Spec Violation Caused by Improper Isolation of Control Rod Drive 42-59

In addition, the following LERs were reviewed by the inspector and corrective actions were verified:

(Closed) 91-04 - Inadequate Fire Protection (Thermolag) of Division II Safe Shutdown Cables Due to Inadequate Installation and Inspection

As a result of a scheduled annual inspection, the licensee discovered deficiencies in the application and installation of Thermolag in two different areas associated with Division II electrical distribution. As corrective action, personnel involved in the inspection of Thermolagged components were instructed in the importance of checking all cable tray surfaces for deficiencies. Further, the thermolag deficiencies were repaired. The inspector verified that the above corrective actions had taken place by reviewing applicable documentation.

(Closed) 91-08 - Entry Into Refueling Mode with Reactor Coolant Temperature Greater Than 140 Degrees (Inadequate Plant Procedures)

Reactor vessel head detensioning had been allowed to commence and continued to proceed for approximately nine hours with reactor coolant temperature greater than 140 degrees. This was a violation of Technical Specifications. As corrective action, the licensee revised three different procedures to remind operators and maintenance crews of this requirement. The procedures revised are as follows:

- PPM 10.3.5, Reactor Vessel Head Removal and Replacement
- PPM 7.4.4.6.1.1D, RPV Head Tensioning/Detensioning Temperature Surveillance
- PPM 7.0.2, Shift and Daily Instrument Checks (Mode 5)

The inspector reviewed the above procedures to verify that the revisions had actually been accomplished.

(Closed) 91-16 - ESF Actuation (Containment Instrument Air) Caused By a Blown Rupture Disk

An ESF actuation occurred in the containment instrument air (CIA) system when a rupture disk on the normal nitrogen supply tank failed, causing a pressure decrease in the system. The actuation consisted of an automatic isolation of the safety related portions of the system, which placed them on backup nitrogen bottles. The root cause analysis determined the cause to be fatigue fracture of the metal rupture disc. Supply tank pressure did not get high enough to cause rupture disc actuation. Relief valves in the system would have actuated at a lower pressure and were later confirmed by testing to have a proper setpoint. However, the root cause analysis also determined that the wrong rupture discs have been traditionally used on the nitrogen supply tank. The rupture discs used have a pressure rating of about 310 psig. The correct ones have a pressure rating of about 368 psig. The inspector noted that these rupture discs have failed 14 times at WNP-2 since plant startup, with similar ESF actuations resulting. The licensee initiated a Plant

Modification Record (PMR) to replace the rupture discs with the correct ones. The inspector found the licensee's actions, and proposed actions, to be appropriate.

No violations or deviations were identified.

10. Exit Meeting

The inspectors met with licensee management representatives periodically during the report period to discuss inspection status, and an exit meeting was conducted with the indicated personnel (refer to paragraph 1) on April 22, 1992. The scope of the inspection and the inspectors' findings, as noted in this report, were discussed with and acknowledged by the licensee representatives.

The licensee did not identify as proprietary any of the information reviewed by or discussed with the inspectors during the inspection.